BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Cause of the February 2021 Cold Weather Event and its Impact on Investor Owned Utilities	)))	**File No. AO-2021-0264**

NOTICE REGARDING FILING OF DOCUMENTS

Issue Date: July 27, 2021

On July 26, 2021, the Southwest Power Pool (SPP) Board received the attached report reviewing the February 2021 cold weather event and SPP's response to that event. The SPP Board accepted this report and made it available to the public. The Commission is filing these documents in this case to make them available for review by interested stakeholders.

BY THE COMMISSION

Morris L Woodruff

Morris L. Woodruff
Secretary

Morris L. Woodruff, Chief Regulatory
Law Judge, by delegation of authority pursuant
to Section 386.240, RSMo 2016.

Dated at Jefferson City, Missouri,
on this 27th day of July, 2021.

SPP Southwest Power Pool

COMPREHENSIVE REVIEW STEERING COMMITTEE UPDATE

JULY 27, 2021

BOARD OF DIRECTORS

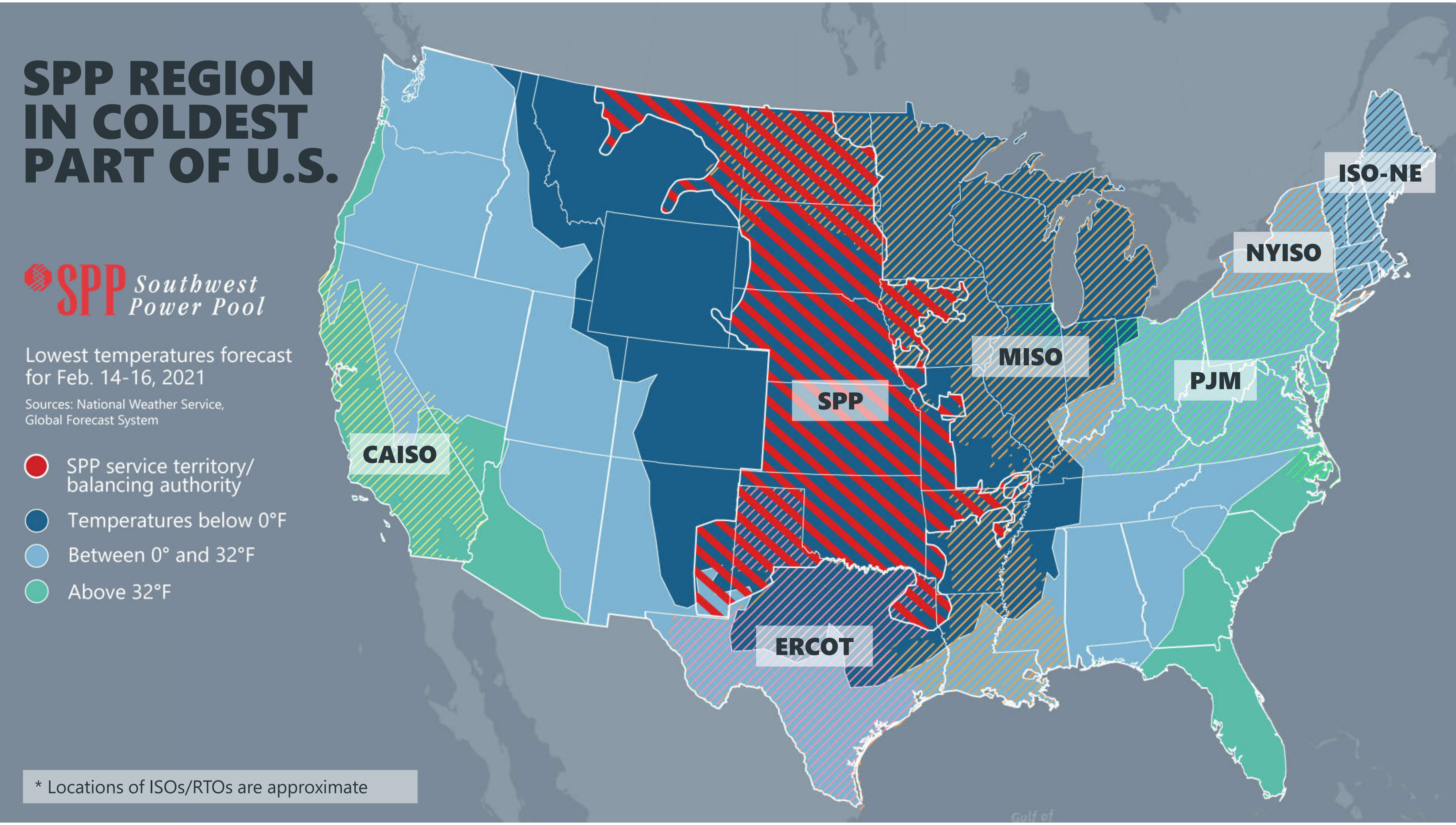
Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool southwest-power-pool SPPorg

COMPREHENSIVE REVIEW STEERING COMMITTEE & STAFF RECOMMENDS THE BOARD

1. Accept its report: "A Comprehensive Review of Southwest Power Pool's response to the February 2021 Winter Storm"
2. Direct work to begin on immediately on recommendations that address root causes (Tier 1)
3. Direct organizational prioritization of work needed to address remaining recommendations
4. Direct staff to provide quarterly updates on status of progress being made.
5. Direct staff to submit for board approval in October a project plan of activities needed to resolve the Tier 1 recommendations.
6. Direct issuance of letters to all generator operators in the SPP region requiring them to inform SPP about their plans to have and maintain fuel necessary to assure availability of all generation treated as accredited capacity for the upcoming winter season.
7. Direct staff to perform additional root cause analyses to explain the failure of natural gas fuel supply during the weather event needed to better inform SPP's three fuel assurance recommendations

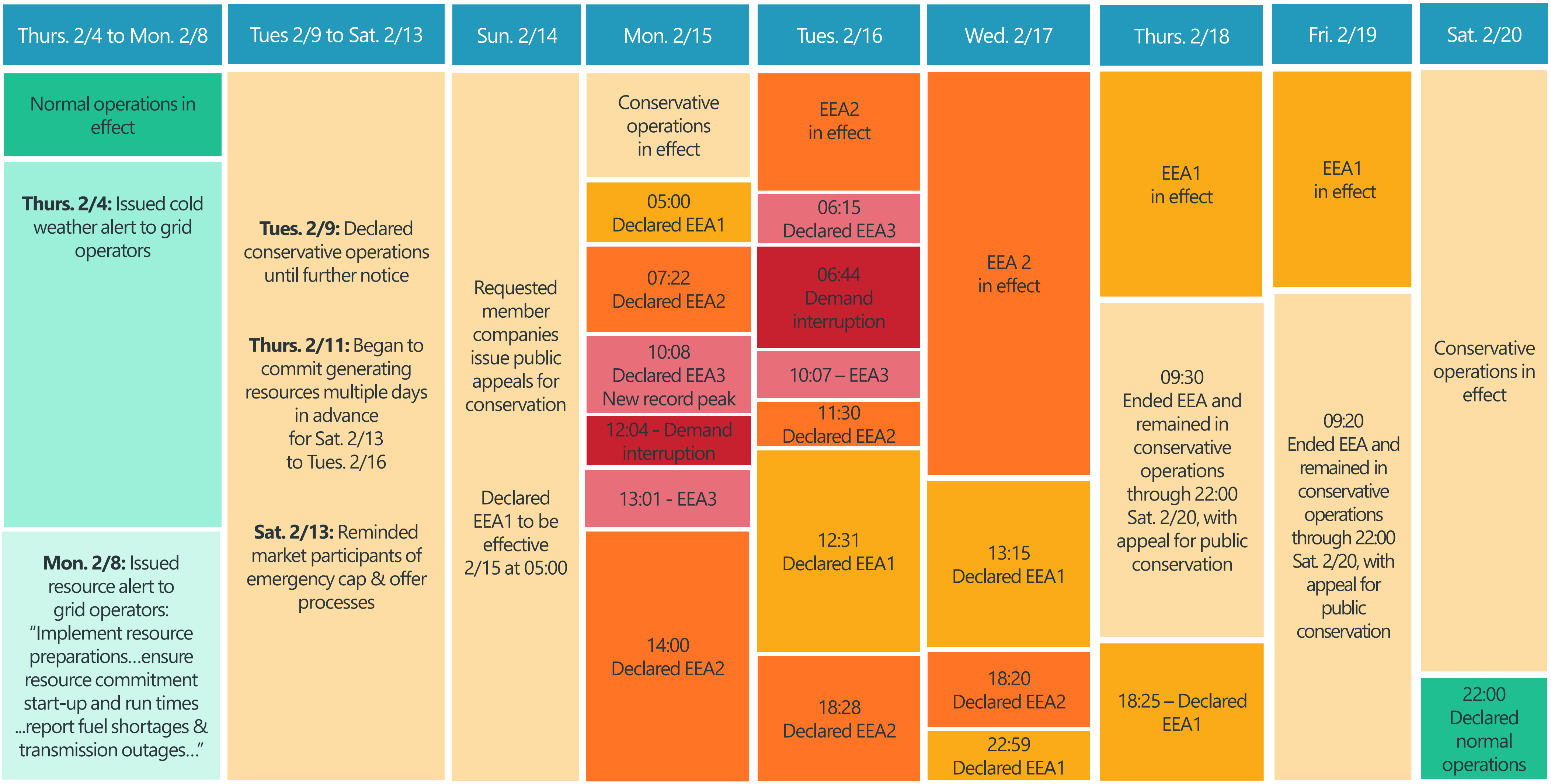
SHORT RECAP OF FEB 2021 WINTER EVENT



SPP REGION IN COLDEST PART OF U.S.
SPP Southwest Power Pool
Lowest temperatures forecast for Feb. 14-16, 2021
Sources: National Weather Service, Global Forecast System
SPP service territory/ balancing authority
Temperatures below 0°F
Between 0° and 32°F
Above 32°F
ISO-NE
NYISO
MISO
PJM
SPP
CAISO
ERCOT
* Locations of ISOs/RTOs are approximate

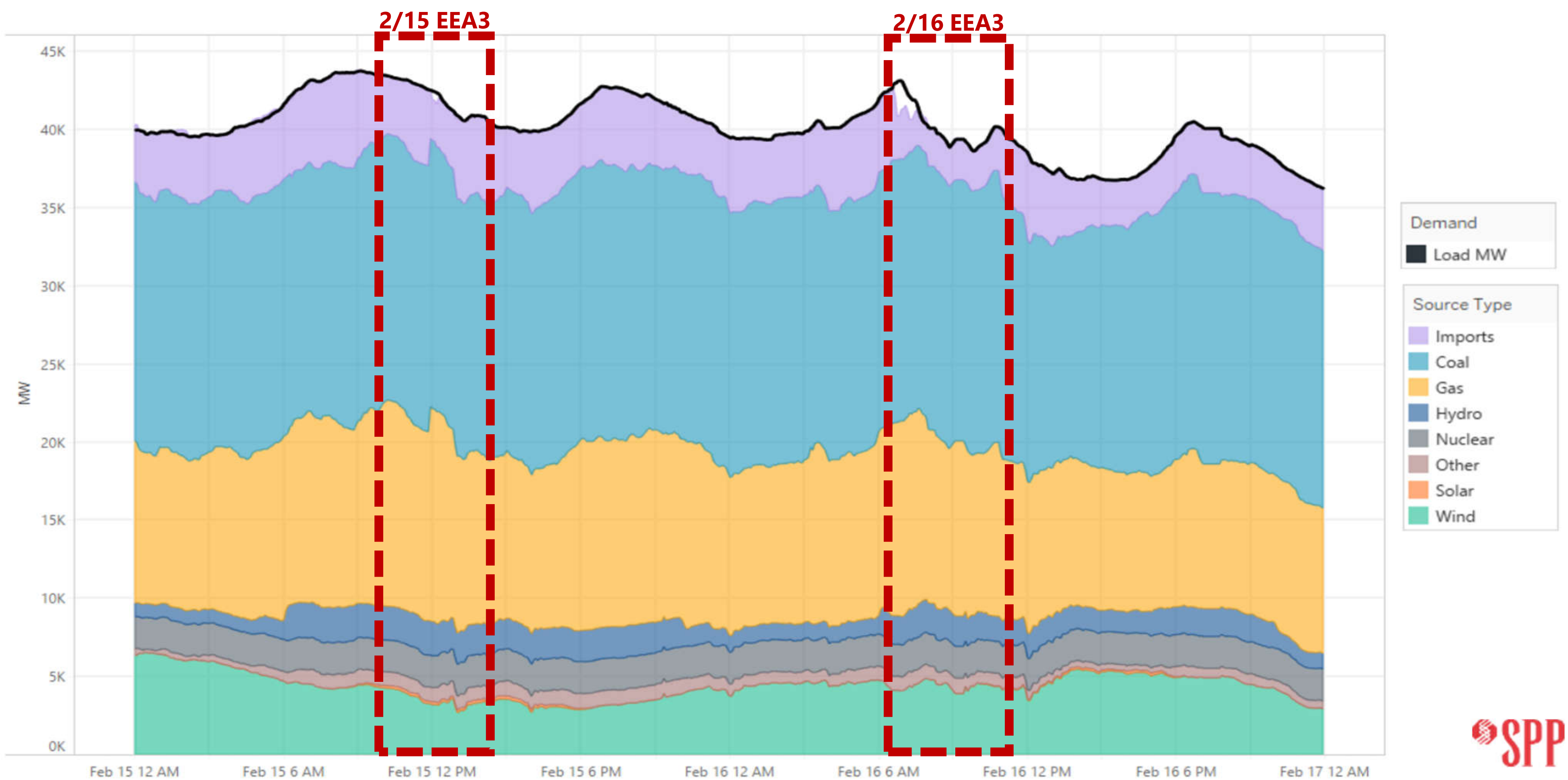
SPP BALANCING AUTHORITY OPERATIONS: FEB. 4-20, 2021

Time blocks are not to scale

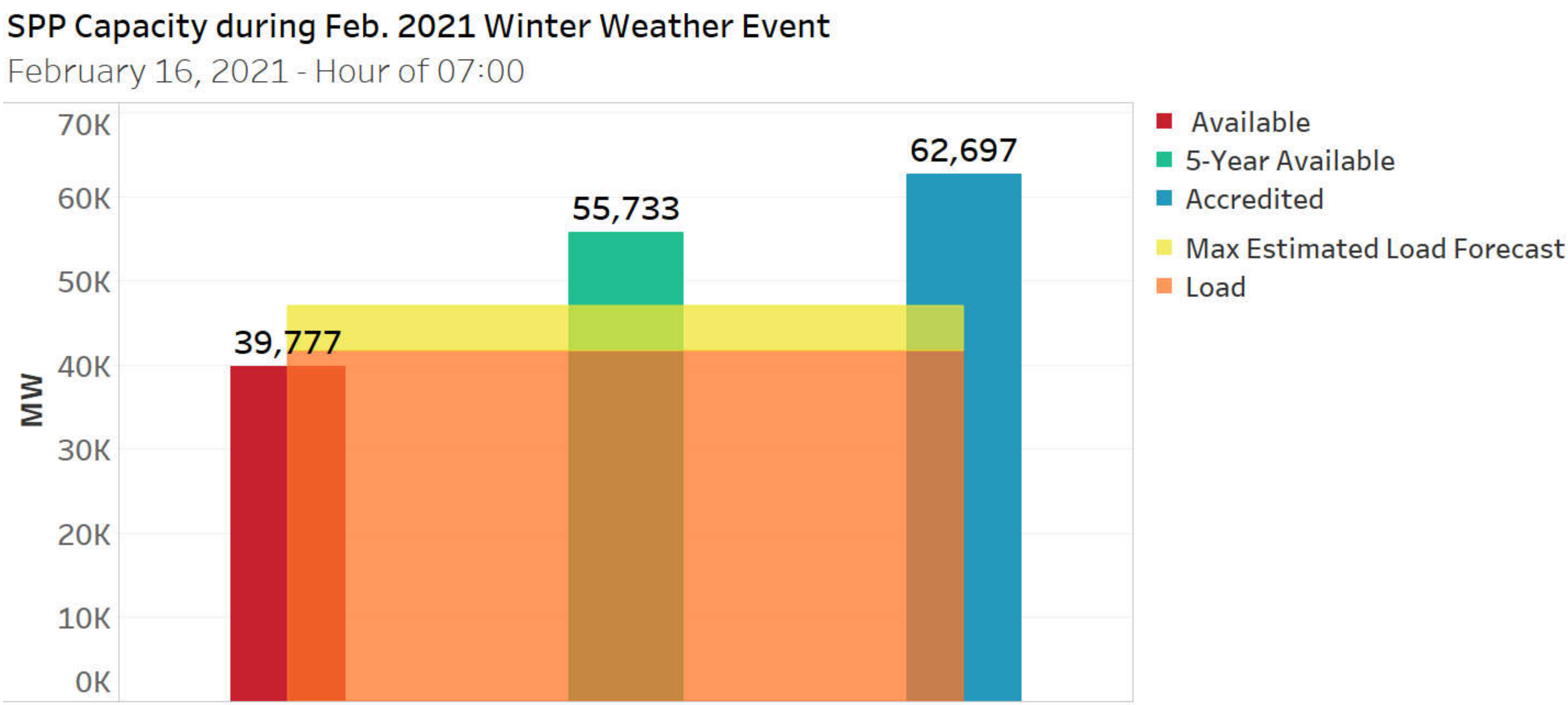


ENERGY THAT MET DEMAND IN REAL-TIME MARKET

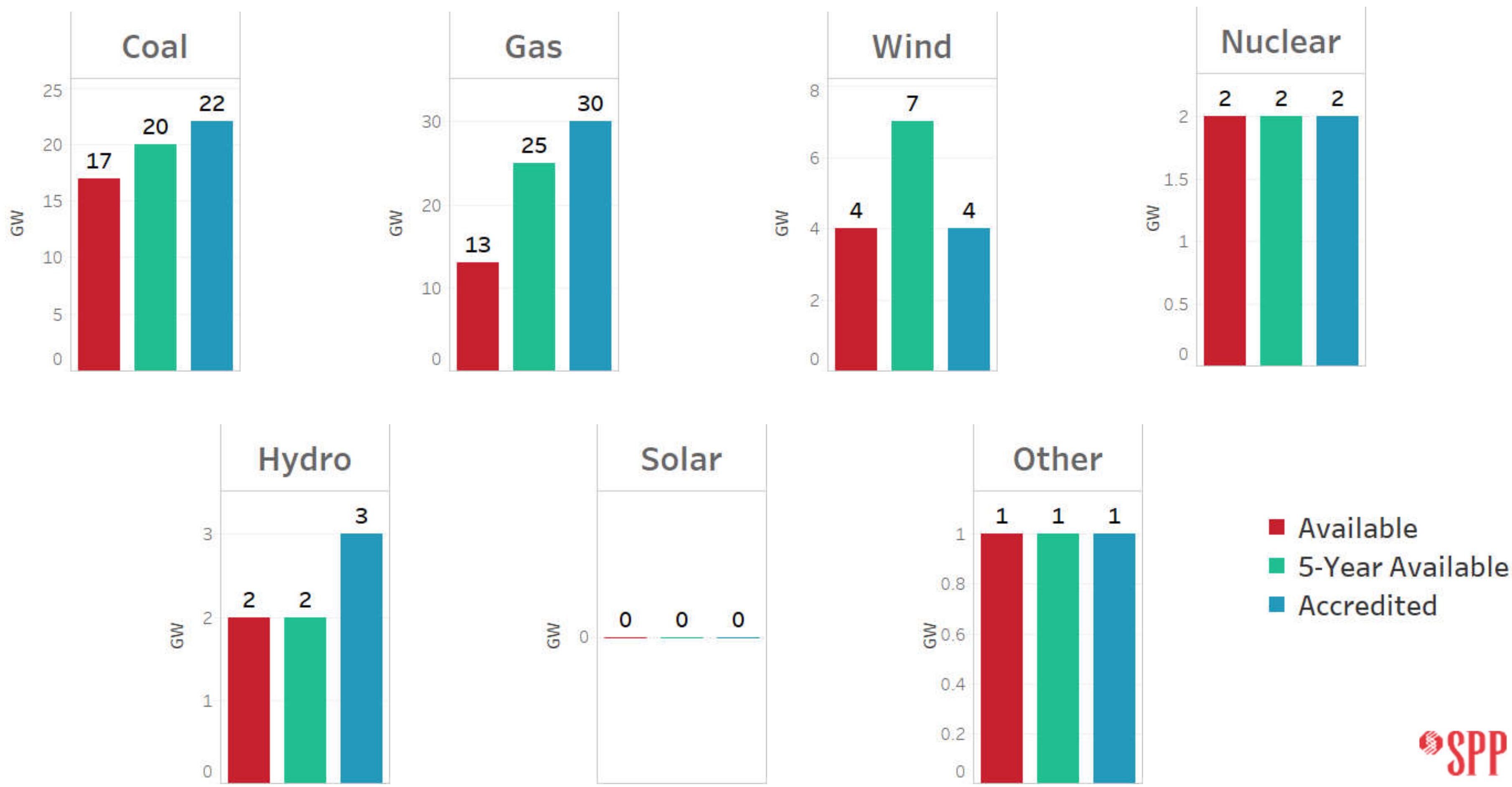
SPP relied on energy from multiple sources, including imports from neighbors



TOTAL CAPACITY BREAKDOWN VS. LOAD



FUEL TYPE CAPACITY BREAKDOWN 02/16/2021 07:00



SPP

COMPREHENSIVE REVIEW STEERING COMMITTEE

COMPREHENSIVE REVIEW STEERING COMMITTEE

Lanny Nickell, Chair
SPP Chief Operating Officer

Larry Altenbaumer
SPP Board Chair

Barbara Sugg
SPP President & CEO

Denise Buffington
Joe Lang
Operational Review Leads

Tom Dunn
Betsy Beck
Financial Review Leads

Kristie Fiegen
RSC Review Lead

Keith Collins
MMU Review Lead

Mike Ross
Communications Review Lead

STAFF & STAKEHOLDER EFFORTS MARCH-JUNE

6 Working Groups

Cost Allocation
Credit Practices
Market
Operating Reliability
Supply Adequacy
Transmission

3 Committees

Finance
Regional State
Markets and Operations

2 Advisory Groups

Seams
Reliability Compliance

Market Monitoring Unit

Ad hoc communications group

250+ stakeholder representatives participate in these groups

SPP Southwest Power Pool

KEY OBSERVATIONS

KEY OBSERVATIONS

1. UNAVAILABLE GENERATION AND FUEL

Lack of available generation was the primary cause of the event's reliability impacts. Lack of fuel was the biggest cause of generation unavailability.

2. HIGH GAS PRICES

Extremely high natural gas prices were the primary driver of record-high energy offers, exceeding SPP's market offer caps for the first time.

KEY OBSERVATIONS

3. INCREASED CREDIT EXPOSURE

Rapid spike in SPP's market prices raised concerns about market participants' liquidity & exponentially increased short-term credit exposure.

4. HELPFUL INTERCONNECTIONS

Relationships & interconnections with neighboring systems facilitated critical helpful assistance.

5. CONGESTED TRANSMISSION

Full use of generation in certain locations was limited by congestion on SPP's system.

KEY OBSERVATIONS

6. MINIMIZED RELIABILITY IMPACTS

Early preparation, timely decisions & effective communication helped minimize reliability impacts while effective execution of load-shed procedures mitigated the risk of uncontrolled blackouts.

7. CREDIBLE COMMUNICATIONS & RESPONSE

Stakeholders indicated general satisfaction with SPP's emergency communications, information sharing & credibility, while recognizing the need for improvements.

Southwest Power Pool

RECOMMENDATIONS OVERVIEW

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PRIORITIZATION LEVELS

TIER 1	Necessary and urgent to avoid severe reliability, financial, operational, compliance or reputational risks. Address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts.
TIER 2	Necessary to minimize the risk of severe reliability, financial, operational, compliance or reputational consequences associated with extreme system events. Important and expected to significantly improve SPP’s response to extreme system events in the future.
TIER 3	Improve SPP’s response, communications and public perception during extreme system events, but are not necessary or urgent.

TIER 2

RECOMMENDATION TYPES

Action: Development and/or implementation of a new process, requirement, protocol or other activity.

Policy: Development of principles to be used to guide subsequent development of requirements, protocols, and/or processes using the stakeholder process in accordance with bylaws, tariff provisions and applicable regulations.

Assessment: Performance of analysis that informs development of solutions through the stakeholder process.

SUMMARY OF RECOMMENDATIONS BY TIER

	Tier 1	Tier 2	Tier 3
Fuel Assurance (FA)	2	1	-
Resource Planning & Availability (RPA)	2	-	-
Emergency Response Process & Planning (ERP)	-	3	-
Operator Tools, Communication and Processes (OTCP)	-	1	-
Seams Agreements (SEAMS)	-	1	-
Market Design (MKT)	-	3	-
Transmission Planning (TXP)	-	1	1
Credit (CR)	-	1	2
Communications (COMM)	-	2	2
22 TOTAL	4	13	5

SUMMARY OF RECOMMENDATIONS BY CATEGORY

	Action	Policy	Assessment
Fuel Assurance (FA)	-	2	1
Resource Planning & Availability (RPA)	-	1	1
Emergency Response Process & Planning (ERP)	1	1	1
Operator Tools, Communication and Processes (OTCP)	1	-	-
Seams Agreements (SEAMS)	1	-	-
Market Design (MKT)	1	2	-
Transmission Planning (TXP)	-	2	-
Credit (CR)	1	-	2
Communications (COMM)	3	-	1
22 TOTAL	8	8	6

RECOMMENDATIONS

FUEL ASSURANCE

#	TIER	TYPE	DRIVER	RECOMMENDATION
FA 1	TIER 1			Develop policies that enhance fuel assurance to improve generation availability & reliability in SPP region
FA 2	TIER 1			Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily & affordably available during extreme events
FA 3	TIER 2			Develop policies to improve gas-electric coordination that better inform & enable improved emergency response

RESOURCE PLANNING & AVAILABILITY

#	TIER	TYPE	DRIVER	RECOMMENDATION
RPA 1	TIER 1			Perform initial & ongoing assessments of minimum reliability attributes needed from SPP's resource mix
RPA 2	TIER 1			Improve or develop policies that ensure sufficient resources will be available during normal & extreme conditions. May include: • Required performance of seasonal resource adequacy assessments • Developing accreditation criteria • Incorporating minimum reliability attribute requirements • Utilizing market-based incentives

EMERGENCY RESPONSE PROCESS & PLANNING (ERP)

#	TIER	TYPE	DRIVER	RECOMMENDATION
ERP 1	TIER 2			Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations
ERP 2	TIER 2			Implement improvements to load-shed processes to be developed by ORWG such as: • Utilize real-time load values when determining load-shed ratio shares • Train & drill on multiple overlapping load-shed instructions • Perform a detailed review of models used to determine load-shed ratio shares • Develop & document procedures & processes to address the timing and responsibility of curtailing exports before & during a load-shed event
ERP 3	TIER 2			Develop a policy to ensure TOP emergency response & load-shed plans have been reviewed, updated & tested annually to verify their effectiveness, with attention to critical infrastructure

OPERATOR TOOLS, COMMUNICATION & PROCESSES (OTCP)

#	TIER	TYPE		RECOMMENDATION
OTCP 1	TIER 2			Develop or enhance ORWG-identified tools, communications & processes to improve SPP & stakeholder response to extreme conditions, such as: • Enhance real-time cascading analysis studies and post results • Develop tool(s) to increase operator awareness of "out of merit energy" instructions • Enhance and expand the use of R-Comm • Create a reliability dashboard to improve situational awareness for operators • Utilize member-maintained distribution lists for communications • Develop a process to update operations management during extreme conditions

SEAMS AGREEMENTS

#	TIER	TYPE	DRIVER	RECOMMENDATION
SEAMS 1	**TIER 2**			Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance & fairly compensate emergency energy

MARKET DESIGN IMPROVEMENTS (MKT)

#	TIER	TYPE	DRIVERS	RECOMMENDATION
MKT 1	TIER 2			Develop & improve policies to ensure price formation & incentives reflect system conditions
MKT 2	TIER 2			Develop & implement MWG-identified market design & market-related enhancements to improve operational effectiveness & ensure governing language provides needed flexibility and clarity, such as: • Improve Dispatch Target Adjustment Process • Enhance Multiday Reliability Assessment Process
MKT 3	TIER 2			Develop policies to ensure financial outcomes during emergency conditions are commensurate with benefits provided

CREDIT & SETTLEMENTS (CR)

#	TIER	TYPE	DRIVERS	RECOMMENDATION
CR 1	TIER 2			Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in first quarter of 2022
CR 2	TIER 3			Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes.
CR 3	TIER 3			Clarify tariff language related to SPP's settlements & credit-related authorities and responsibilities

TRANSMISSION PLANNING IMPROVEMENTS (TXP)

#	TIER	TYPE	DRIVERS	RECOMMENDATION
TXP 1	TIER 2			Develop policies that facilitate transmission expansion to improve SPP's ability to more effectively utilize transmission system during severe events
TXP 2	TIER 3			Develop transmission planning policies that improve input data, assumptions or analysis techniques needed to better account for severe events

COMMUNICATIONS RECOMMENDATIONS (COMM)

#	TIER	TYPE	DRIVERS	RECOMMENDATION
COMM 1	TIER 2			Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: • Processes that ensure stakeholders have a dependable way to receive timely, accurate & relevant information regarding emergencies • Plans to drill emergency communications procedures with all relevant stakeholders • Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers & government entities and stay up-to-date
COMM 2	TIER 2			Evaluate & propose needed enhancements to communications tools & channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc.
COMM 3	TIER 3			Form a stakeholder group whose scope would include matters related to emergency communications
COMM 4	TIER 3			To increase public awareness of & satisfaction with SPP, develop materials to educate general audiences on foundational electric utility industry concepts & SPP's role in ensuring reliability

RECOMMENDATION TO BOARD

COMPREHENSIVE REVIEW STEERING COMMITTEE & STAFF RECOMMENDS THE BOARD

1. Accept its report: "A Comprehensive Review of Southwest Power Pool's response to the February 2021 Winter Storm"
2. Direct work to begin on immediately on recommendations that address root causes (Tier 1)
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7. Direct staff to perform additional root cause analyses to explain the failure of natural gas fuel supply during the weather event needed to better inform SPP's three fuel assurance recommendations

MARKET MONITORING UNIT INDEPENDENT ANALYSIS

KEITH COLLINS

EXECUTIVE DIRECTOR, MARKET MONITORING

TIER 1

CRITICAL RECOMMENDATIONS

- Ensure resource availability through more granular capacity evaluations and accounting for seasonal and forced outages
- Create meaningful incentives for availability
- Establish monthly or seasonal resource adequacy requirements
- Plan for supply-side shocks to the market driven by multiple types of events

CATEGORY: Critical

TIER 1

GAS-ELECTRIC COORDINATION

- Coordinate with regulators and natural gas industry to:
  - Appreciate operational interdependencies and address issues that could cause harm to SPP's system
  - Appreciate market dynamics and address concerns with capped electricity markets and uncapped natural gas markets
  - Develop trading approach that addresses the needs of natural gas-fired resources to be able to start up quickly and on short notice

CATEGORY: Gas-electric coordination

TIER 2 AND TIER 3 RECOMMENDATIONS

TIER 2

TIER 3

- Address concerns identified with the following topics:
  - FERC Order No. 831 processes
  - Price formation
  - Outages
  - Scheduling and dispatch
  - Behind the meter generation
  - Credit
  - Communications

CATEGORY: Other recommendations

DISCUSSION AND Q&A

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Q&A

- Will first take questions from Board of Directors and Members Committee & Regional State Committee
- Next, will take questions from other stakeholders
- Please send follow-up questions or media inquiries to communication@spp.org

Southwest Power Pool published the following report on July 26, 2021. In a special meeting of SPP's Board of Directors and Members Committee, SPP's Comprehensive Review Steering Committee and staff recommended that the board:

1. Accept its report, "A Comprehensive Review of Southwest Power Pool's response to the February 2021 Winter Storm".

2. Direct work to begin immediately on recommendations that address root causes (Tier 1).

3. Direct organizational prioritization of work needed to address remaining recommendations.

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Southwest Power Pool

A COMPREHENSIVE REVIEW OF SOUTHWEST POWER POOL'S RESPONSE TO THE FEBRUARY 2021 WINTER STORM

ANALYSIS AND RECOMMENDATIONS

By Southwest Power Pool

Published on July 19, 2021

Version 1.0

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EXECUTIVE SUMMARY

As a regional transmission organization (RTO) tasked with ensuring the reliable delivery of electricity to a 14-state region, Southwest Power Pool (SPP) experienced the most operationally challenging week in its 80-year history during Feb. 14-20, 2021. Many locations across the entire SPP service territory, from North Dakota to the Texas panhandle, experienced record-low temperatures for days on end. As consumers' use of electricity and natural gas increased in response to the cold, power producers simultaneously faced fuel-supply issues and equipment malfunctions, transmission system equipment approached unsafe operating limits, and the overall reliability of the bulk electric system was severely tested.

Despite the challenges of managing record wintertime electricity use, generation unavailability, fuel-supply issues, transmission congestion and historically high energy costs, SPP kept the lights on across its region throughout the winter storm, with two short exceptions. SPP directed its transmission operators (TOP) to curtail electricity use by temporarily interrupting their customers' electric service twice: once to lessen regional energy consumption by about 1.5% for 50 minutes Feb. 15 and again to lessen it by about 6.5% for a little more than three hours Feb. 16. Underscoring the historic significance of the February 2021 winter weather event, these marked the first times in the organization's history that SPP has called for regionwide curtailments.

In a special meeting of the SPP Board of Directors and Members Committee on March 2, 2021, the board directed a comprehensive review of SPP's and its stakeholders' response to the February storm. The review was organized to analyze operational, financial, communications and other aspects of the events of Feb. 14-20, and to identify how the organization can learn, adapt and be better prepared for future extreme threats to reliability.

Five teams were tasked with evaluating a multitude of factors related to the event, and a steering committee was formed[1]. The five teams' areas of focus, the stakeholder groups and other audiences who primarily contributed input to their reviews, and team leaders are summarized in the table below.

[1] The Comprehensive Review Steering Committee comprised each teams' leader plus board chair Larry Altenbaumer, Members Committee representatives Joe Lang (Omaha Public Power District) and Betsy Beck (Enel Green Power North America), SPP President and CEO Barbara Sugg, and SPP COO Lanny Nickell, who chaired the committee.

Table 1: Comprehensive review teams' focus areas, representation and leadership

REVIEW TEAM	FOCUS AREAS	STAKEHOLDER GROUPS REPRESENTED	TEAM LEAD
Operations	Operational reliability Balancing authority Market performance Resource adequacy Transmission planning	Markets and Operations Policy Committee, Operating Reliability Working Group, Market Working Group, Transmission Working Group, and Supply Adequacy Working Group	**Denise Buffington** MOPC chair, Evergy director of regulatory affairs **Joe Lang** Members Committee representative, Omaha Public Power District director of energy regulatory affairs
Finance	Settlement and credit issues	Finance Committee, Settlements User Forum, Credit Practices Working Group	**Tom Dunn** Finance Committee staff secretary, SPP chief financial officer **Betsy Beck** Members Committee representative, Enel Green Power North America director, organized markets
Communications	Protocols and coordination related to operational, stakeholder, governmental and public communications	Communications representatives from stakeholder organizations	**Mike Ross** SPP senior vice president of government affairs and public relations
Regional State Committee	Resource adequacy and cost allocation	Regional State Committee, Cost Allocation Working Group	**Commissioner Kristie Fiegen** Regional State Committee president, South Dakota Public Utilities commissioner
Market Monitoring Unit	Actual gas costs for settlements purposes Market behavior and rules issues How the markets worked overall	Independent review	**Keith Collins** SPP MMU executive director

This report represents the findings and recommended directional objectives generated during the comprehensive review, as consolidated, synthesized and summarized by SPP staff. A report produced by SPP's independent Market Monitoring Unit (MMU) is published separately and is available on SPP.org along with other MMU reports.

KEY OBSERVATIONS

The comprehensive review yielded seven key observations regarding the root causes of the winter storm's impact, SPP's response and its preparedness to respond to future reliability events.

1. The unavailability of generation, driven mostly by lack of fuel, was the largest contributing factor to the severity of the winter weather event's impacts[2], which was exacerbated by record wintertime energy consumption[3] and a rapid reduction of energy imports[4].

   This root cause drives the need to develop policies that improve fuel assurance and resource adequacy and highlights the need to further assess SPP's ability to reliably operate the system with more intermittent and fewer base-load resources. Better coordination and communication between the gas and electric industries could have significantly improved preparation activities.

2. Extremely high natural gas prices were the primary driver of record-high energy offers that exceeded the FERC-required offer cap of $1,000/megawatt-hour (MWh) for the first time in SPP's market history. On Feb. 15, SPP's market price reached an all-time high of $4,274.96/MWh in the day-ahead market. By comparison, the average price of energy in SPP's day-ahead market for the entire year of 2020 was $17.69/MWh. Natural gas markets are not subject to price or offer caps, while electricity markets like SPP's are.

3. The rapid spike in SPP's market prices resulted in an immediate concern about liquidity of market participants and created an exponential increase in short-term credit exposure.[5]

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[2] Up to approx. 59,000 MW of generating nameplate capacity in SPP was unavailable to meet demand during the week of the event. When generation was most needed on Feb. 16, about 30,000 MW of generating capacity was unavailable due to forced outages. The largest single cause of these forced generation outages was attributed to fuel-supply issues, causing nearly 47% of the outages and affecting over 13,000 MW of gas generation.

[3] SPP set a new winter peak load of 43,661 MW the morning of Feb. 15 and likely would have reached a wintertime peak of 47,000 MW if not for conservation and curtailments.

[4] Reductions in imports were due to transmission congestion and tightening supply conditions in neighboring areas. Between 2,000 and 2,500 MW of imports were quickly reduced on both Feb. 15 and 16, contributing to SPP's need to shed load each day.

[5] SPP sought and received a waiver from FERC extending the cure period for load serving entities to satisfy calls for financial security.

4. Relationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event, with net amounts exceeding 6,000 megawatts (MW) at times. This emphasizes the value these relationships and robust transmission interconnections provide during emergency events and the opportunity to further strengthen them.

5. The SPP transmission system was highly congested at times during the event with limitations that prevented full use of generation available in certain locations.[6] This issue exacerbated SPP's need to achieve balance between regional supply and demand through use of its load-shed procedures and raised questions about the appropriateness of regionally allocating load-shed responsibilities.

6. Early preparation, timely decisions and effective communication helped minimize the winter storm's impact on reliability. Early communication of a public appeal for conservation contributed to reduced demand Feb. 15, reducing the amount of controlled service interruptions required. Effective communication of and prompt response to load-shed instructions likewise mitigated the risk of uncontrolled blackouts.

7. SPP's stakeholders indicated general satisfaction with SPP's emergency communications, information sharing and credibility related to the winter storm response, although some areas of improvement were identified, particularly in those related to end-use customer awareness.

More on these key observations and related issues can be found in the following sections provided later in this report:

- Analysis of Operations and Market Performance
- Analysis of Finance, Settlements and Credit
- Analysis of Communications

RECOMMENDATIONS

Throughout the comprehensive review, SPP staff and stakeholders evaluated hundreds of potential process changes, system enhancements, new and amended policies, further assessments, and other potential solutions meant either to address the root causes of the February 2021 event's impact on the SPP system or to better enable SPP and its stakeholders to respond to future extreme system events. Ultimately, this report recommends 22 actions, policy changes and assessments categorized in three tiers[7] according to urgency, importance, impact

[6] SPP experienced 54 transmission constraints at the time load shedding began Feb. 16 that resulted in nearly 1,900 MW of generation being reduced to maintain reliable energy flows on those facilities.
[7] Of these 22 recommended objectives, four are tier 1, thirteen are tier 2 and five are tier 3.

and other factors. Full implementation of many of these recommendations will be subject to further approvals as prescribed by SPP bylaws.

Recommendations are categorized according to a three-tier ranking system defined as follows:

- **Tier 1:** Recommended actions, policies or assessments deemed necessary and urgent to avoid severe reliability, financial, operational, compliance or reputational risks.

  These recommendations are expected to address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts.

  Upon board approval, work associated with implementation of these recommendations shall be prioritized by the organization at the highest level and begin immediately.

- **Tier 2:** Recommended actions, policies or assessments deemed necessary to minimize the risk of severe reliability, financial, operational, compliance or reputational consequences associated with extreme system events.

  These recommendations may not address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts, but are important, are expected to significantly improve SPP's response to extreme system events in the future, and shall be treated as high-priority initiatives.

- **Tier 3:** Recommended actions, policies or assessments that would improve SPP's response, communications and public perception during extreme system events, but are not urgent.

Recommendations are also categorized into one of three possible types, defined as follows:

- **Action**: Development and/or implementation of a new process, requirement, protocol or other activity.

- **Policy**: Development of principles to be used to guide subsequent development of requirements, protocols, and/or processes using the stakeholder process in accordance with bylaws, tariff provisions and applicable regulations.

- **Assessment**: Performance of analysis that informs development of solutions through the stakeholder process.

FUEL ASSURANCE

Table 2: Summary of recommendations to the board related to fuel assurance

#	TIER	CATEGORY	RECOMMENDATION
FA 1	1	Policy	Develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region.
FA 2	1	Assessment	Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events.
FA 3	2	Policy	Develop policies to improve gas-electric coordination that better inform and enable improved emergency response.

RESOURCE PLANNING AND AVAILABILITY

Table 3: Summary of recommendations to the board related to resource planning and availability

#	TIER	CATEGORY	RECOMMENDATION
RPA 1	1	Assessment	Perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix.[8]
RPA 2	1	Policy	Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives[9] that ensure sufficient resources will be available during normal and extreme conditions.

[8] The Holistic Integrated Tariff Team's (HITT) recommendation R1 should be considered when addressing RPA 1.
[9] HITT recommendation R2 should be considered when addressing this part of RPA 2.

EMERGENCY RESPONSE PROCESSES AND PLANNING

Table 4: Summary of recommendations to the board related to emergency response processes and planning

#	TIER	CATEGORY	RECOMMENDATION
ERP 1	2	Assessment	Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations.
ERP 2	2	Action	Implement improvements to load-shed processes to be developed by the Operating Reliability Working Group (ORWG), such as: • Utilize real-time load values when determining load-shed ratio shares. • Train and drill on multiple overlapping load-shed instructions. • Perform a detailed review of models used to determine load-shed ratio shares. • Develop and document procedures and processes to address the timing and responsibility of curtailing exports before and during a load-shed event.
ERP 3	2	Policy	Develop a policy to ensure TOP emergency response and load-shed plans have been reviewed, updated and tested on an annual basis to verify their effectiveness, with attention to critical infrastructure.

OPERATOR TOOLS, COMMUNICATION AND PROCESS

Table 5: Summary of recommendations to the board related to operator tools, communications and processes

#	TIER	CATEGORY	RECOMMENDATION
OTCP 1	2	Action	Develop or enhance the tools, communications and processes identified by the ORWG and needed to improve SPP and stakeholder response to extreme conditions, such as: • Enhance real-time cascading analysis studies and post results. • Develop tool(s) to increase operator awareness of Out of Merit Energy (OOME) instructions. • Enhance and expand the use of R-Comm.[10] • Create a reliability dashboard to improve situational awareness for operators. • Utilize member-maintained distribution lists for communications purposes. • Develop a process to update operations management during extreme conditions.

[10] R-Comm is the Reliability Communications tool, the primary means of communication for responsible entities to receive, acknowledge and carry out load-shed instructions issued by the SPP Balancing Authority.

SEAMS AGREEMENTS

Table 6: Summary of recommendations to the board related to seams agreements

#	TIER	CATEGORY	RECOMMENDATION
SEAMS 1	2	Action	Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance and fairly compensate emergency energy.

MARKET DESIGN

Table 7: Summary of recommendations to the board related to market design

#	TIER	CATEGORY	RECOMMENDATION
MKT 1	2	Policy	Develop and improve policies to ensure price formation and incentives reflect system conditions.
MKT 2	2	Action	Develop and implement market design and market-related enhancements identified by the Market Working Group to improve operational effectiveness and ensure governing language provides needed flexibility and clarity, such as: • Improve the Dispatch Target Adjustment Process. • Enhance the Multiday Reliability Assessment Process.[11]
MKT 3	2	Policy	Develop policies to ensure financial outcomes during emergency conditions are commensurate with the benefits provided.

TRANSMISSION PLANNING

Table 8: Summary of recommendations to the board related to transmission planning

#	TIER	CATEGORY	RECOMMENDATION
TXP 1	2	Policy	Develop policies that facilitate transmission expansion needed to improve SPP's ability to more effectively utilize the transmission system during severe events.
TXP 2	3	Policy	Develop transmission planning policies that improve input data, assumptions or analysis techniques needed to better account for severe events.

[11] HITT recommendations R3 and R4 should be considered when addressing MKT 2.

CREDIT AND SETTLEMENTS

Table 9: Summary of recommendations to the board related to credit and settlements

#	TIER	CATEGORY	RECOMMENDATION
CR 1	2	Assessment	Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in the first quarter of 2022.
CR 2	3	Assessment	Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes.
CR 3	3	Action	Clarify tariff language related to SPP's settlements and credit-related authorities and responsibilities.

COMMUNICATIONS

Table 10: Summary of recommendations to the board related to communications

#	TIER	CATEGORY	RECOMMENDATION
COMM 1	2	Action	Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: • Processes that ensure stakeholders have a dependable way to receive timely, accurate and relevant information regarding emergencies. • Plans to drill emergency communications procedures with all relevant stakeholders. • Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers, and government entities and stay up-to-date.
COMM 2	2	Assessment	Evaluate and propose needed enhancements to communications tools and channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc.
COMM 3	3	Action	Form a stakeholder group whose scope would include discussion of matters related to emergency communications.
COMM 4	3	Action	To increase public awareness of and satisfaction with SPP, develop materials intended to educate general audiences on foundational electric utility industry concepts and SPP's role in ensuring electric reliability.

COMPREHENSIVE REVIEW PROCESS

SPP's comprehensive review of the February 2021 winter weather event included input from SPP staff and representatives of stakeholder groups including members, market participants, SPP's independent market monitor, regulators, elected officials and members of the media, among others. A steering committee was formed to ensure coordination and communication among parallel efforts conducted by the five teams identified below. Members of the steering committee were:

Lanny Nickell, Chair (SPP chief operating officer)

Larry Altenbaumer (Chair of the SPP Board of Directors)

Barbara Sugg (SPP president and chief executive officer)

Betsy Beck: Finance review co-lead (Members Committee representative, Enel Green Power North America director, organized markets)

Denise Buffington: Operations review lead (Evergy director of regulatory affairs)

Keith Collins: Market monitoring review lead (Executive director of SPP Market Monitoring Unit)

Tom Dunn: Finance review lead (SPP chief financial officer)

Kristie Fiegen: Regional State Committee review lead (South Dakota Public Utilities commissioner)

Joe Lang: Operations review co-lead (Members Committee representative, OPPD director of energy regulatory affairs)

Mike Ross: Communications review lead (SPP senior vice president of government affairs and public relations)

Reporting to the steering committee were five teams tasked with performing their own evaluations of various aspects of the February winter weather event's impacts. Each team's roster and scope are identified below along with notes regarding their evaluation process and/or outcomes.

OPERATIONS REVIEW

Four of SPP's working groups reviewed the event to develop recommendations: the Market Working Group (MWG), Operating Reliability Working Group (ORWG), Supply Adequacy Working Group (SAWG) and Transmission Working Group (TWG).

Operations Review Leads

Denise Buffington, chair
Evergy, SPP MOPC chair

Joe Lang
Omaha Public Power District

Market Working Group

Richard Ross, MWG chair
American Electric Power-Southwestern Electric Power

Jim Flucke, MWG vice chair
Evergy Companies

Erin Cathey, MWG staff secretary
SPP

Aaron Rome
Midwest Energy

Betsy Beck
Enel Green Power North America

Carrie Dixon
Xcel Energy

Chandler Brown
Sunflower Electric Power Corporation

Eric Alexander
Grand River Dam Authority

Jack Clark
NextEra Energy Resources

Jack Madden
East Texas Electric Cooperatives

John Varnell
Tenaska Power Services

Lee Anderson
Lincoln Electric System

Michael Massery
Arkansas Electric Cooperative Corporation

Neal Daney
Kansas Municipal Energy Agency

Rick Yanovich
Omaha Public Power District

Shawn Geil
Kansas Electric Power Cooperative

Shawn McBroom
Oklahoma Gas and Electric

Valerie Weigel
Basin Electric Power Cooperative

Yohan Sutjandra
City Utilities of Springfield

Operating Reliability Working Group

Allen Klassen, ORWG chair
Evergy Companies

Ron Gunderson, ORWG vice chair
Nebraska Public Power District

Zachary Sharp, ORWG staff secretary
SPP

Abubaker Elteriefi
ITC

Allan George
Sunflower Electric Power

Bryn Wilson
Oklahoma Gas & Electric

Chance Myers
Western Farmers Electric Cooperative

Chris Shaffer
American Electric Power

David Pham
The Empire District

Doug Peterchuck
Omaha Public Power District

Gary Plummer
Independence Power & Light

Jeff Wells
Grand River Dam Authority

Jim Useldinger
GridLiance High Plains

John Roemen
Western Area Power Administration

Keith Carman
Tri-State Generation and Transmission Association

Kyle McMenamin
Southwestern Public Service Company /Xcel Energy

Laurie Gregg
Lincoln Electric System

Mark Eastwood
City Utilities of Springfield

Matt Pawlowski
NextEra Energy Resources

Supply Adequacy Working Group

Natasha Henderson, SAWG chair
Golden Spread Electric Cooperative

Tom Hestermann, SAWG vice chair
Sunflower Electric Power Corporation

Chris Haley, SAWG staff secretary
SPP

Aaron Castleberry
Oklahoma Gas & Electric

Aaron Ramsdell
Basin Electric Power Cooperative

Adam Graff
Heartland Consumers Power District

Amy Newton
City Utilities of Springfield

Bennie Weeks
Xcel Energy Services

Brian Berkstresser
Liberty Utilities

Colton Kennedy
Omaha Public Power District

David Sonntag
Western Farmers Electric Cooperative

Eric Alexander
Grand River Dam Authority

Ernesto Perez
East Texas Electric Cooperative & Northeast Texas Electric Cooperative

Jeffrey Plew
NextEra Energy Resources

Jim Jacoby
American Electric Power-Public Service Co of OK

Jodi Knutson
WAPA

John Varnell
Tenaska Power Services

Robert Janssen
Dogwood Energy

Thomas Saitta
Kansas Municipal Energy Agency

Timothy Cerveny
Nebraska Municipal Power Pool

Traci Bender
Nebraska Public Power District

Walt Cecil, CAWG liaison
Missouri Public Service Commission

Transmission Working Group

Nathan McNeil, TWG chair
Midwest Energy

Derek Brown, TWG vice chair
Evergy Companies

Adam Bell, TWG staff secretary
Southwest Power Pool

Andrew Berg
Missouri River Energy Services

Arash Ghodsian
EDF Renewables Development

Chris Pink
Tri-State Generation and Transmission Association, Inc.

Clifford Franklin
Sunflower Energy

Gayle Nansel
Western Area Power Administration

James Ging
Kansas Power Pool

Jarred Cooley
Xcel Energy

Jason Shook
East Texas Electric Cooperative

Jim McAvoy
Oklahoma Municipal Power Authority

Joe Fultz
Grand River Dam Authority

John Boshears
City Utilities of Springfield, Missouri

John Knofczynski
East River Electric Power Cooperative

Joshua Verzal
Omaha Public Power District

Kalun Kelley
Western Farmers Electric Cooperative

Matthew McGee
American Electric Power

Michael Mueller
Arkansas Electric Cooperative Corporation

Michael Wegner
ITC Holdings

Nate Morris
Liberty Utilities

Noman Williams
GridLiance High Plains

Phil Westby
Basin Electric Power Cooperative

Randy Lindstrom
Nebraska Public Power District

Scott Benson
Lincoln Electric System

Shane McMinn
Golden Spread Electric Cooperative

Steve Hardebeck
Oklahoma Gas & Electric

SCOPE OF WORK

Immediately after the winter storm, SPP staff began analyzing the event. Staff prepared a draft report and shared it with members of the MWG, ORWG, SAWG and TWG. The report included information pertaining to operational activities and observations before and during the events.

The working groups met multiple times to review the draft event report and develop recommendations. The SAWG held six executive sessions to discuss the event and reviewed the recommendations at three regular meetings. The ORWG held 13 executive sessions dedicated to the event and discussed it at one regular meeting. The TWG held four executive sessions to discuss the event and reviewed recommendations at two regular meetings. The MWG held seven executive sessions dedicated to the event and discussed it at three regular meetings. The four groups held a joint executive session where all members could come together to collaborate.

FINANCIAL REVIEW

Staff from SPP's accounting, settlements and credit departments conducted SPP's financial analysis of the February 2021 winter weather event and validated their observations with the Finance Committee and Credit Practices Working Group.

Financial Review Leads

Tom Dunn, chair
SPP chief financial officer

Betsy Beck
Enel Green Power North America

SPP Staff

Brent Wilcox
SPP settlements

Dana Boyer
SPP settlements

Dianne Branch
SPP accounting

Don Shipley
SPP settlements

Jared Barker
SPP credit

Scott Smith
SPP credit

Steve White
SPP settlements

Tony Alexander
SPP settlements

Zeynep Vural
SPP accounting

Finance Committee

Susan Certoma, Chair
SPP Board of Directors

Sandra Bennett
American Electric Power

Julian Brix
SPP Board of Directors

Darcy Ortiz
SPP Board of Directors

Matt Pawlowski
NextEra Energy Resources

Sarah Stafford
OGE Energy

Al Tamimi
Sunflower Electric Power

Mike Wise
Gold Spread Electric Cooperative

Credit Practices Working Group

Caleb Head, CPWG chair
Northeast Texas Electric Cooperative

Mark Breese, CPWG vice chair
Xcel Energy

Seth Cochran
DC Energy

Tom Hestermann
Sunflower Electric Power Corporation

Mark Holler
Tenaska Power Services

LaGena O'Neal
Oklahoma Municipal Power Authority

Jason Regehr
City Utilities of Springfield, MO

Justin Riddell
The Energy Authority

Matthew Simon
Basin Electric Power Cooperative

Zachary Wegner
Omaha Public Power District

Terri Wendlandt
Evergy

SCOPE OF WORK

SPP's financial review focused on credit implications, settlement impacts and communication of financial matters as related to the February 2021 winter weather event. The observations and analysis detailed in the Analysis of Finance, Settlements and Credit section of this report are based on survey data, analysis of settlement disputes, the content of Request Management System tickets and settlement runs conducted by staff.

COMMUNICATIONS REVIEW

The Communications Comprehensive Review Team (CCR) comprised the following representatives of SPP and its stakeholder organizations. Its roster was intended to include individuals with responsibilities related to corporate communications, public relations, regulatory and government affairs and related fields, and to represent all of SPP's geographic regions and types of members.

Mike Ross, chair
SPP

Carl Stelly
SPP

CJ Brown
SPP

David Kimmel
OGE Energy

David Mindham
EDP Renewables

Derek Wingfield
SPP

Don Martin
SPP

Dustin Smith
SPP

Gina Penzig
Evergy

Jean Schafer
Basin Electric Power Cooperative

Jillian Janik
SPP

John McClure
Nebraska Public Power District

Kara Fornstrom
SPP

Kirkley Thomas
Arkansas Electric Cooperatives

Laura Lutz
Evergy

Lee Elliott
SPP

Leslie Sink
SPP

Lisa Meiman
Western Area Power Administration

Mark Becker
Nebraska Public Power District

Meghan Sever
SPP

Peter Main
American Electric Power/Southwestern Electric Power Company

Rae Rice
OGE Energy

Commissioner Randy Christmann
North Dakota Public Service Commission

Rob Roedel
Arkansas Electric Cooperatives

Russell Carey
SPP

Steve Gaw
Advanced Power Alliance

Tessie Kentner
SPP

Usha Turner
OGE Energy

Victor Schock
North Dakota Public Service Commission

SCOPE OF WORK

The CCR gathered documentation and data of relevant SPP communication from Feb. 4 through Feb. 20, and conducted an analysis of the processes, policies, staffing and resources used to conduct them. Analysis and recommendations covered four categories of communications:

- Operational communications.
- Stakeholder communications.
- Governmental and regulatory communications.
- Public communications (press, end-users and general public).

For each category, the CCR analyzed:

- What legal or standard requirements exist for SPP communication.
- How SPP's communication during the event met requirements.
- What procedures exist for additional communication.
- SPP's performance of internal procedures and processes.
- Communication performed by peers during the event.
- Other communication needs (perceived ⁄ expressed ⁄ relative) of operators, stakeholders, government and the public related to the event.

For each category, the CCR made recommendations to improve:

- *Internal* communication processes:
    - Interdepartmental communication.
    - Flow and responsibility of communication.
    - Resources provided for communication.
- *External* communication processes:
    - Effectiveness and timeliness of external communication.
    - Inclusion in each type of communication.
    - Stakeholder-driven communication process improvement.
    - Education about RTO emergency procedures and processes.
- *Member-conducted* communication processes:
    - Resources provided to SPP members to aid in communication.
    - Recommendations for standardizing public appeals and other processes.

For topics beyond the timeline and scope of the comprehensive review process, the CCR made some recommendations for additional analysis and recommendations, including topics for organizational groups or task forces to address in the future.

REGIONAL STATE COMMITTEE REVIEW

The Regional State Committee (RSC) of state utility commissioners, along with its Cost Allocation Working Group (CAWG), reviewed the winter event.

Regional State Committee

Kristie Fiegen, RSC chair
South Dakota Public Utilities Commission

Randel Christmann, RSC vice chair
North Dakota Public Service Commission

Paul Suskie, RSC staff secretary
SPP

Andrew French
Kansas Corporation Commission

Dana Murphy
Oklahoma Corporation Commission

Dennis Grennan
Nebraska Power Review Board

Geri Huser
Iowa Utilities Board

Jefferson Byrd
New Mexico Public Regulation Commission

Mike Francis
Louisiana Public Service Commission

Scott Rupp
Missouri Public Service Commission

Ted Thomas
Arkansas Public Service Commission

Will McAdams
Public Utility Commission of Texas

Cost Allocation Working Group

Greg Rislov, CAWG chair
South Dakota Public Utility Commission

Victor Schock, CAWG vice chair
North Dakota Public Service Commission

Lee Elliott, CAWG staff secretary
SPP

Adam McKinnie
Missouri Public Service Commission

Anna Hyatt
Iowa Utilities Board

Cindy Ireland
Arkansas Public Service Commission

Harika Basaran
Public Utility Commission of Texas

Jason Chaplin
Oklahoma Corporation Commission

John Krajewski
Nebraska Power Review Board

John Reynolds
New Mexico Public Regulation Commission

Lane Sisung
Louisiana Public Service Commission

Shari Albrecht
Kansas Corporation Commission

SCOPE OF WORK

RSC President Kristie Fiegen created the Cost Allocation Working Group Ad Hoc Task Force in response to the extreme weather event. The task force members were John Krajewski, John Reynolds and Shari Albrecht. The task force was charged with gaining a broad understanding of the factors that resulted in the emergency and developing recommendations related to the RSC's authority: cost allocation, financial transmission rights, resource adequacy and transmission planning for remote resources.

The task force interfaced with SPP staff, the MMU, the SAWG and the RSC in developing their recommendations. In total, the RSC review team held 32 meetings to discuss the event and develop recommendations.

The task force's report is posted on the SPP.org RSC page.

MARKET MONITORING UNIT REVIEW

Keith Collins, executive director of SPP's independent Market Monitoring Unit (MMU), led the MMU's review of the winter event. MMU staff invested a significant amount of effort into researching and analyzing what happened during the storm, including issues related to FERC Order No. 831, price formation, generation outages, scheduling and dispatch, and gas-electric coordination.

They engaged with the MWG, SAWG, ORWG, CPWG, CAWG, and communications review team to hear stakeholder concerns and discuss issues. The MMU held discussions with the Federal Energy Regulatory Commission and other independent system operators/regional transmission organizations regarding the event and related best practices.

The MMU's report and recommendations are posted to the MMU's page on SPP.org.

EVENTS OF FEB. 4-20

The winter weather event of February 2021 was historic in nature, requiring SPP to take steps to preserve the reliability of the regional power grid that it has not previously taken in its 80-year history. The entire SPP balancing authority (BA) region, stretching from the Canadian border in the north to the Texas panhandle in the south, was impacted by extreme cold temperatures that lasted days. This led to increased electricity use at the same time a number of factors limited generators' ability to produce power. Still, over the course of the week, SPP limited service interruptions to a total of just more than four hours spread over two days.

On the following pages are a timeline and review of the events leading up to, during and immediately following the winter storm. This report's appendices contain additional background information on subjects pertaining to SPP's role in managing regional reliability and preparing for winter-weather events like this one. See the appendices for information on these and other background topics:

- SPP's and its members' roles in assuring electric reliability
- Winter-weather preparation and training taken by SPP and stakeholder operations staff
- Industry standards related to SPP's and its members obligations during the winter weather event
- Findings and SPP's response to prior winter-weather reliability events in 2011 and 2018

The section titled Analysis of Operational and Market Performance presents a detailed evaluation and observations regarding the events described above.

Figure 1 is an illustrated timeline of SPP Balancing Authority operations from Feb. 4-20, 2021, followed by a high-level overview of five phases of the event: early forecasts, conservative operations, the declaration of a series of energy emergency alerts, controlled interruptions of service, and a period of lessening severity concluding with a return to normal operations. Note that time blocks in the following illustration are not to scale.

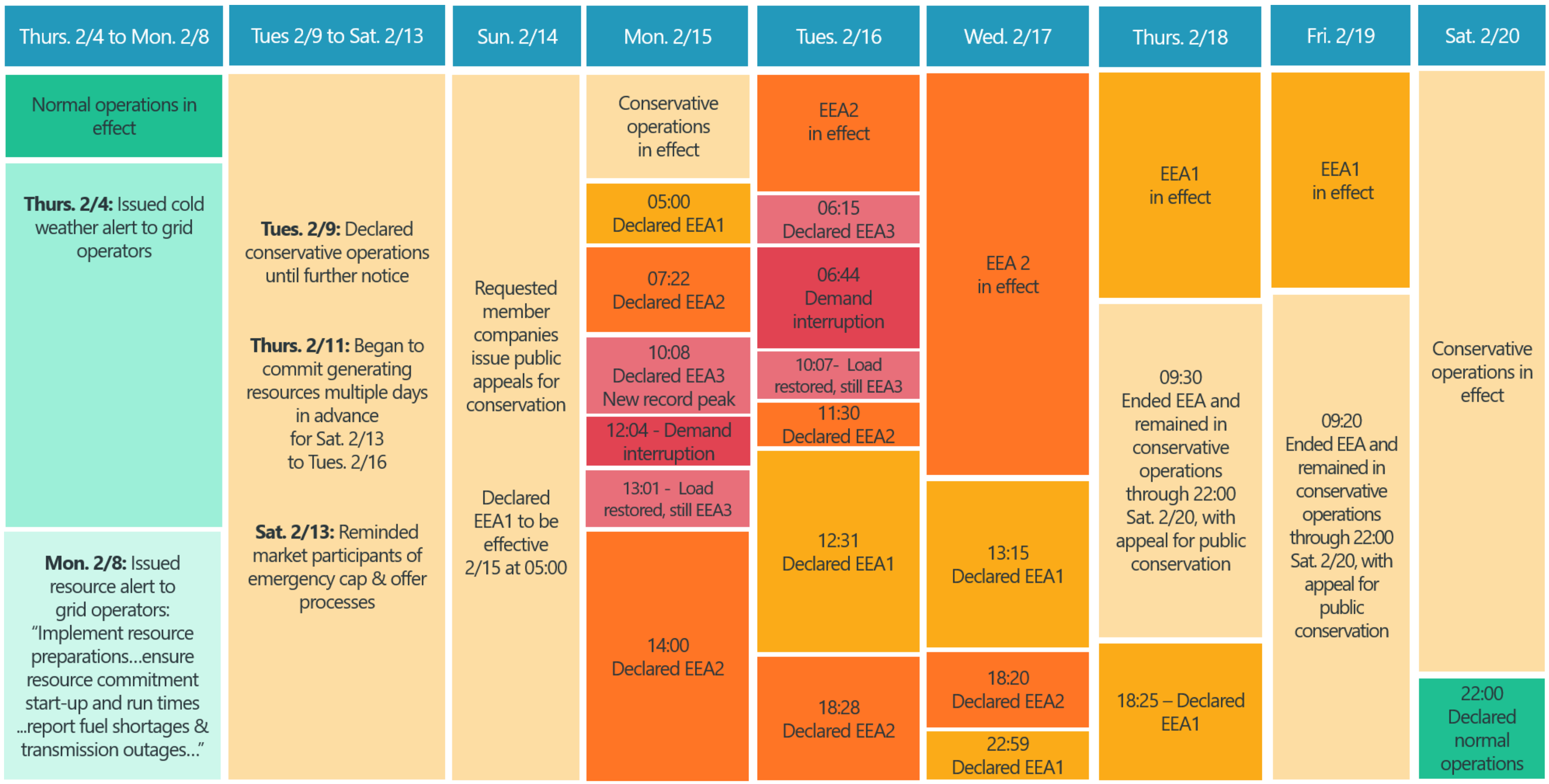

Figure 1: Timeline of BA Operations (Feb. 4-20, 2021)

REVIEW OF FEB. 4-20 ACTIVITIES

WEATHER

In February 2021, a major winter storm impacted the SPP region and much of the continental United States. On Feb. 14, the National Weather Service Prediction Center tweeted, "This cold snap is forecast to result in record low temperatures that are comparable to the historical cold snaps of Feb 1899 & 1905."[12] According to the National Operating Hydrologic Remote Sensing Center, on Feb. 16, about 73% of the mainland U.S. was covered in snow.[13] On Feb. 19, the National Weather Service tweeted that over 3,000 daily record cold temperatures had been reported, and within that dataset were 79 all-time cold records.[14]

The SPP region was inside the coldest portion of the continental U.S., as depicted in the following map.

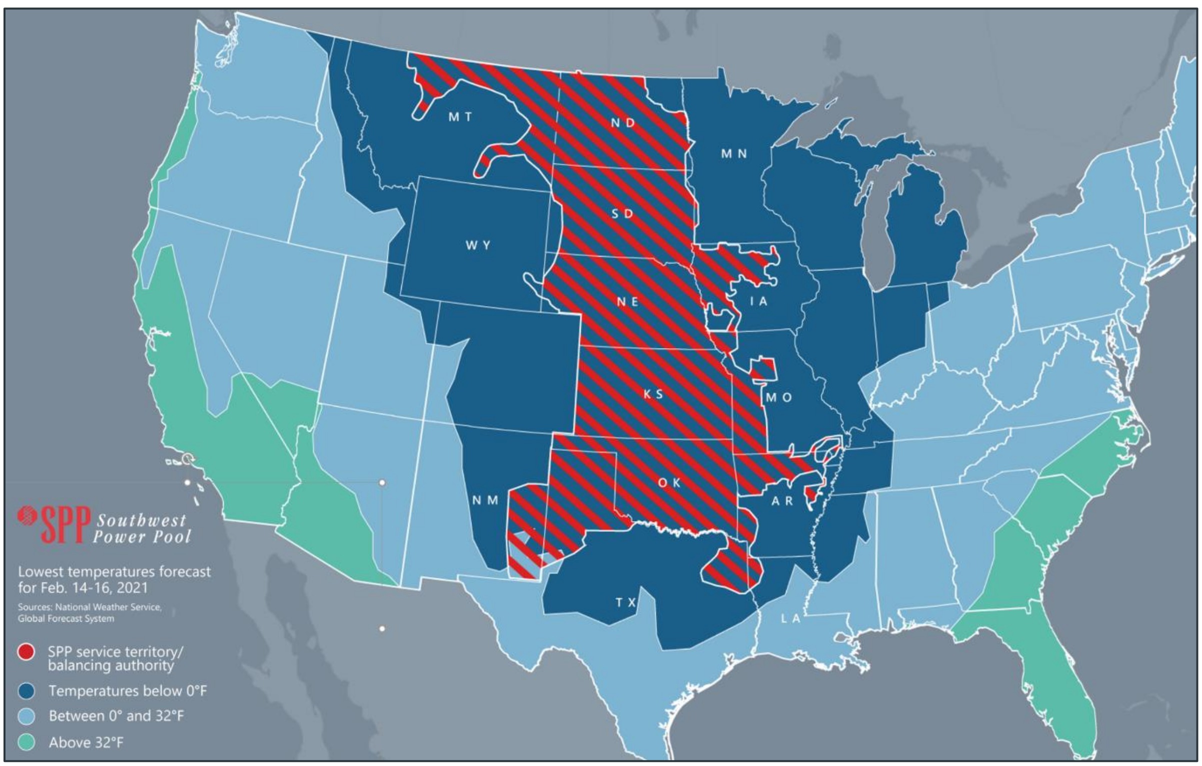

Figure 2: Low-Temperature Map

12 https://twitter.com/NWSWPC/status/1361000008519086085
13 https://www.nohrsc.noaa.gov/nsa/index.html?region=National&year=2021&month=2&day=16&units=e
14 https://twitter.com/NWSWPC/status/1362953109681672199

EARLY FORECASTS

First communication to member utilities about possible impacts of the winter storm occurred Feb. 4, 10 days before the storm hit.

1. **Feb. 4:** SPP issued a Cold Weather Alert effective Feb. 6. A Cold Weather Alert signals that forecasts anticipate extreme weather that could impact grid reliability.

2. **Monday, Feb. 8 at 10 a.m.**: SPP escalated status to Resource Alert. A Resource Alert signals that member utilities should implement resource preparations, ensure resource commitment startup and run times, and report fuel shortages and transmission outages that might impact normal operations.

CONSERVATIVE OPERATIONS AND OTHER PREPARATORY ACTIVITIES

3. **Tuesday, Feb. 9 at 12 a.m.**: SPP declared a period of Conservative Operations until further notice. SPP does this periodically when weather, environmental, operational or other events prompt us to operate the system conservatively to avoid an emergency.

4. **Thursday, Feb. 11**: SPP began committing generating resources using its multiday reliability assessment process. Instead of committing generation a day ahead, as is standard practice, SPP began sending instructions to generators several days in advance that they would be responsible for serving load for the period Saturday, Feb. 13 through Tuesday, Feb. 16.

ENERGY EMERGENCY ALERTS AND PUBLIC APPEALS

5. **Sunday, Feb. 14**

    a. **9:27 a.m.**: SPP emailed a declaration of an Energy Emergency Alert (EEA) Level 1 beginning Feb. 15, 2021, at 5 a.m. due to concerns regarding expected weather and fuel-supply issues.

    b. **1:57 p.m.**: SPP requested member utilities make public appeals for energy conservation effective beginning on Feb. 15.

    This marks the first time in SPP's history it has taken this step. A public appeal is a tool SPP has available to lessen electricity use when it forecasts that its generating capacity and reserves are at risk. A public appeal for conservation precedes service interruptions by calling for voluntary reductions, in hopes it will prevent the need for mandatory curtailments.

6. **Monday, Feb. 15 at 5 a.m.:** The SPP BA entered EEA Level 1 for its entire region. EEA Level 1 signals that all available generation is in use.

   Due to the expected severity of this winter storm's impacts, SPP had already issued a public appeal for conservation by this time. Public appeals typically follow an EEA Level 1, but SPP determined if public conservation were to have the desired effect, it would have to be done quickly. The decision proved beneficial: Actual load came in under forecast, at least partly because people responded and used less electricity than predicted.

7. **Monday, Feb. 15 at 7:22 a.m.:** SPP escalated to EEA Level 2. This marks the first time it had ever done so for its entire region.

   EEA Level 2 indicates that in addition to using all available generation, operating reserves are at risk of dropping below minimum requirements. It is at this point SPP typically would direct public appeal for conservation, but it had already done so given the extreme conditions the SPP BA region faced.

8. **Monday, Feb. 15 at 8:58 a.m.:** Even as load came in under forecast, SPP set an all-time peak of 43,661 megawatts (MW) for systemwide electricity use in winter across its region. This underscores the historic nature of this event: Even while using tools like voluntary conservation appeals, SPP still set a new winter peak.

9. **Monday, Feb. 15 at 10:08 a.m.:** SPP declared its first-ever regionwide EEA Level 3, the most severe of three EEA levels.

   EEA Level 3 indicates energy reserves have dropped below minimum requirements, meaning SPP has to find additional generation — by importing it or bringing another plant online — or lessen regionwide electricity use to keep the system in balance.

CONTROLLED INTERRUPTIONS OF SERVICE

10. **Monday, Feb. 15 at 12:04 p.m.:** Two hours after declaring an EEA Level 3, and having exhausted all other options, SPP directed member utilities to deliberately curtail region's energy use by 1.5%. This controlled interruption of service (also called a "load-shed event" lasted 57 minutes.

    When SPP directs controlled interruptions, it spreads their impacts across the whole region. For example, if demand exceeds supply by 100 MW, SPP asks each transmission operator (TOP) throughout the region to decrease electricity use by a proportional share to bring the whole system back into balance. The most load a single TOP was asked to shed during this interruption was 101 MW, or about 17% of the total by which we needed to lessen regional energy use at the time.

    It's up to each TOP to determine how to lessen its use, whether by curtailing residential, commercial or industrial load. SPP has no visibility into and has no authority to direct

how utilities lessen their load. In other words, there's no way for SPP to see or direct whether that reduction comes from particular homes, neighborhoods, farms, businesses, factories, etc. SPP simply monitors the aggregate impact of TOPs' actions to ensure the reliability of the regional grid.

11. **Monday, Feb. 15 at 1:01 p.m.**: SPP restored all load, bringing an end to the period of controlled interruptions of service that began at 12:04 p.m.

12. **Monday, Feb. 15 at 2 p.m.:** SPP declared an EEA Level 2, having restored minimum reserves, and remained in an EEA Level 2 for the duration of that day.

13. **Tuesday, Feb. 16**: The region's electricity use rose again during the typical morning peak — a natural occurrence as people woke up, raised their thermostats, began using appliances, went to work, etc.

14. **Feb. 16 at 6:15 a.m.:** SPP declared a second EEA Level 3.

15. **Feb. 16 at 6:44 a.m.:** SPP directed its member TOPs to implement controlled interruptions of service for a second time.

    The second interruption of service lasted three hours and 21 minutes and was required to lessen regional electricity use by 6.5%. As before, SPP spread the impact out across the region, asking TOPs to decrease their use by a proportional share of this total 6.5% reduction. The most a single entity had to shed in this event was about 227 MW, again about 17% of the total by which SPP needed to lessen total regional energy use.

16. **Feb. 16 at 10:07 a.m.:** SPP restored load, bringing an end to the second and final controlled interruption of service of the winter weather event.

RETURN TO NORMAL OPERATIONS

17. Throughout the remainder of the week, from **Tuesday, Feb. 16 at 11:30 a.m. until Friday, Feb. 19 at 9:20 a.m.**, SPP fluctuated between EEA Levels 1 and 2, de-escalating to Conservative Operations with no EEAs for several hours (9:30 a.m.-6:25 p.m.) on Thursday, Feb. 18.

18. **Saturday, Feb. 20 at 10 p.m.**: SPP declared an end to all applicable alerts and returned to normal operations.

EARLY GENERATION COMMITMENTS

Per the SPP BA Emergency Operating Plan, during a period of conservative operations, the SPP BA may take actions including the use of greater unit commitment notification timeframes, and making commitments prior to the day-ahead market (DAMKT) and/or committing resources in reliability status.

During the week of Feb. 7, SPP was notified of growing concerns about natural gas availability for the upcoming week. Staff worked to ensure all available resources were utilized.

SPP carried out several multiday Reliability Unit Commitment (RUC) studies, committing resources of various lead times well in advance of the DAMKT. These commitments were issued to give early notice that the resources would be needed in real time and that fuel should be procured accordingly. Figure 3 shows the amount of economic maximum capacity committed in each of the market's assessments, distinguished by case (i.e., the results of each assessment). The horizontal axis indicates the timeframe for which the commitments were made.

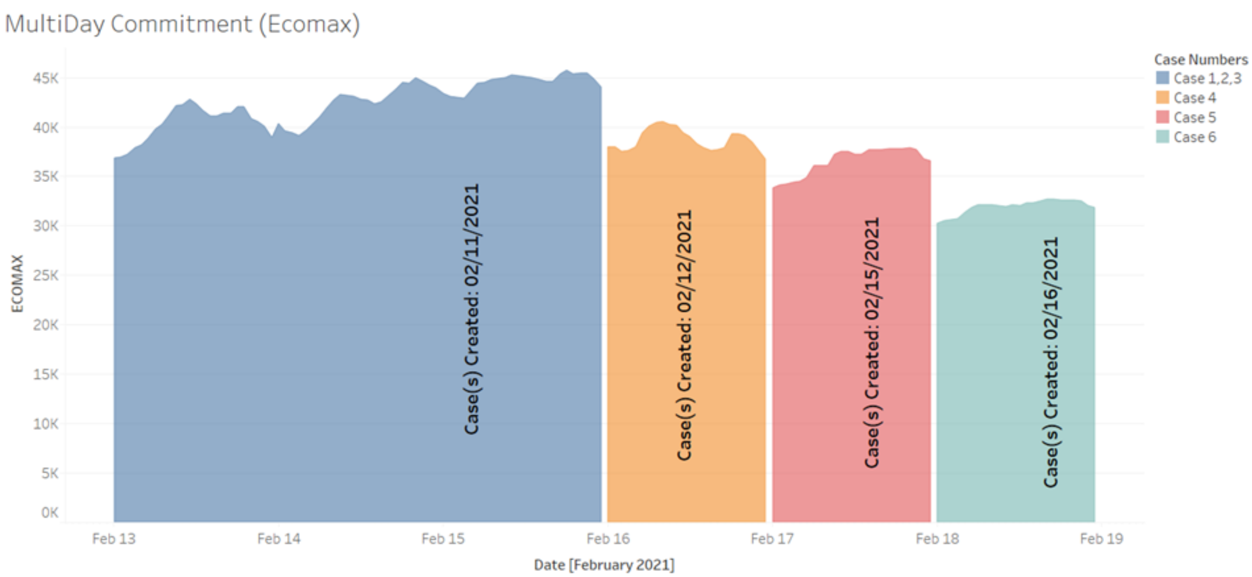

Figure 3: Multiday Commitment Cases

RESCHEDULED TRANSMISSION OUTAGES

Beginning Feb. 9, operations planning staff worked with TOPs to reschedule 134 transmission outages planned to take place Feb. 14-19. Figure 4 illustrates the number of outages rescheduled by kilovolt level. Outages that were previously implemented or were due to emergent work were not rescheduled. Approximately 130 transmission outages of various equipment types and voltage levels were ongoing throughout the event. Outages that were previously implemented or were due to emergent work were not rescheduled.

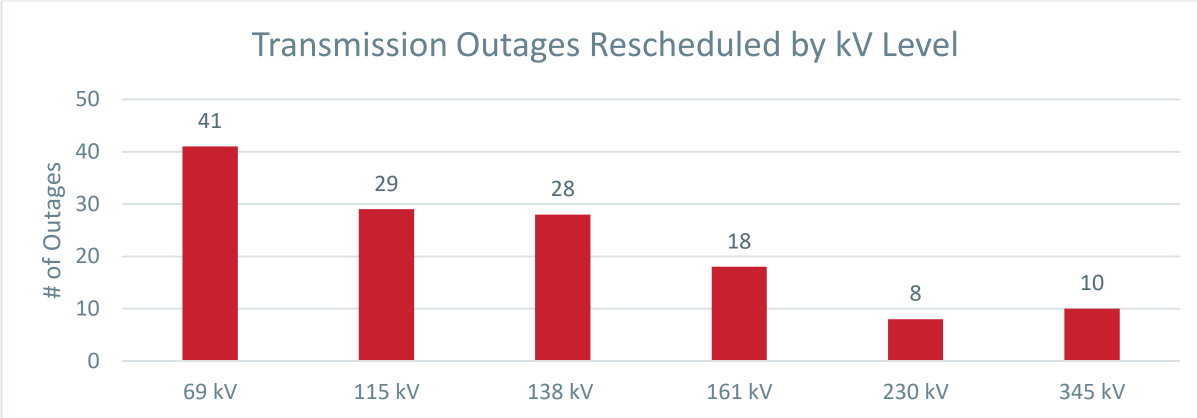

Figure 4: Rescheduled Transmission Outages (Feb. 14-19)

RESCHEDULED GENERATION OUTAGES

SPP allows a certain amount of planned generation outages on the system during the month of February. Over the last five years, planned generation outages during this time of year average around 6,000 MW. As shown in Figure 5, planned outages ran higher than normal during the early part of February but dipped below historical averages during the winter event.[15] This was primarily due to proactive efforts taken to reschedule planned maintenance.

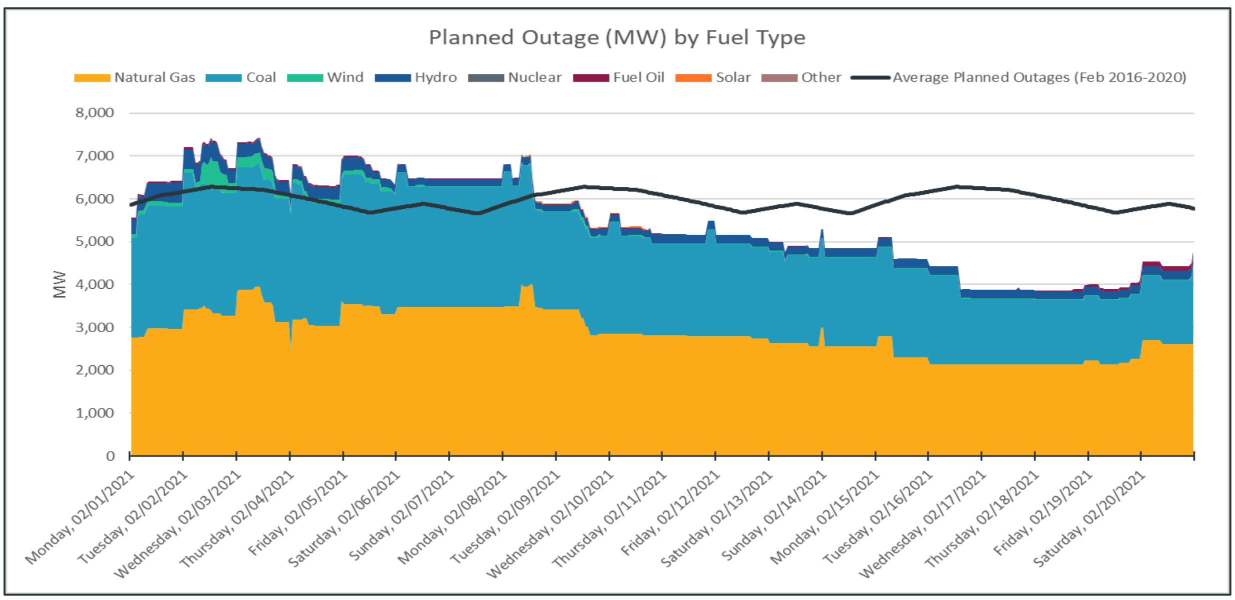

Figure 5: Planned Outages by Fuel Type (Feb. 1-20, 2021)

[15] Due to the nature of some planned outage maintenance, certain outages were not recallable during February 14-19.

Operations planning staff began working with GOPs on Feb. 9 to reschedule generation outages planned to take place Feb. 14-19. Outages that were previously implemented or were due to emergent work were not rescheduled. Resources in the midst of maintenance work may not have been recallable and maintained the original schedule.

Figure 6 illustrates the number of outages and associated capacity rescheduled by fuel type. The rescheduled outages account for roughly 4 gigawatts (GW) of generation capacity. The data includes outages that were canceled, moved or denied.

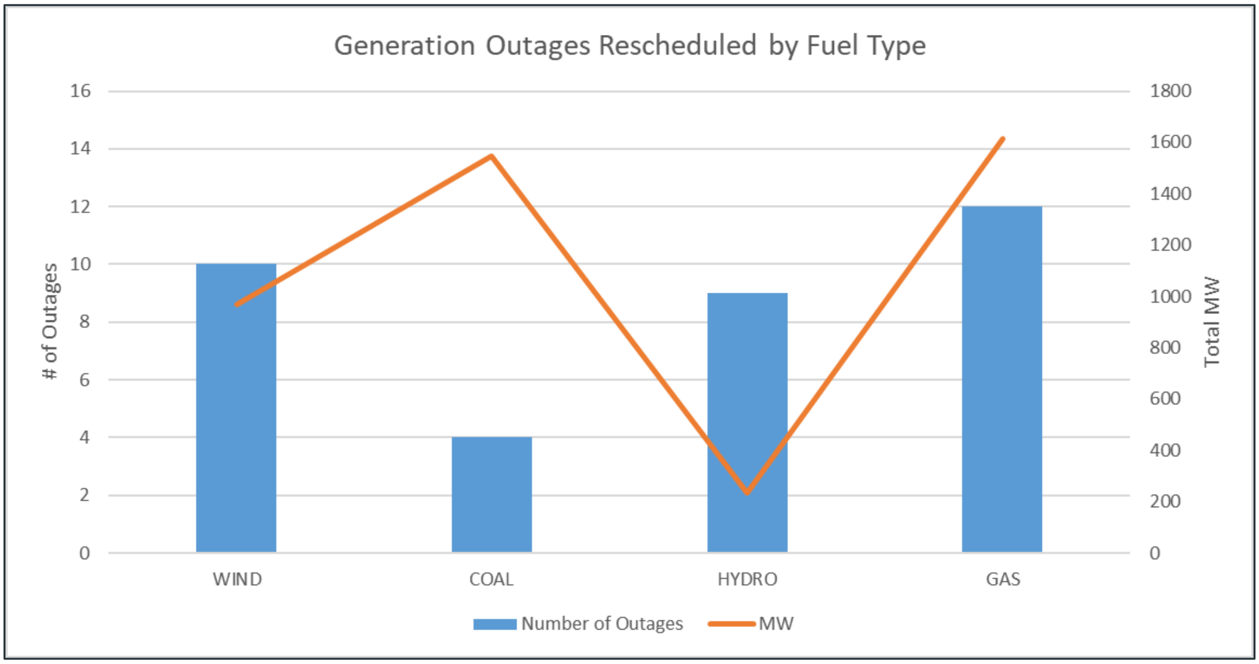

Figure 6: Rescheduled Generation Outages (Feb. 14-19)

LOAD

SPP experienced high winter load levels for multiple days leading up to Feb. 15. On the morning of Feb. 15, load reached 43,661 MW surpassing SPP's previous winter load peak of 43,584 MW set Jan. 17, 2018. It is noteworthy that this new winter load peak was reached Feb. 15 while SPP was taking actions, including issuing public requests for energy conservation, to reduce system load. SPP's midterm load forecasting applications projected load in excess of 44,000 MW for Feb. 15 and 47,000 MW for Feb. 16.

It is difficult to accurately determine how much higher SPP's system load may have been had load management procedures not been in effect during those times but it is likely SPP's previous winter load peak would have been surpassed by nearly 8% if sufficient generating resources had been available.

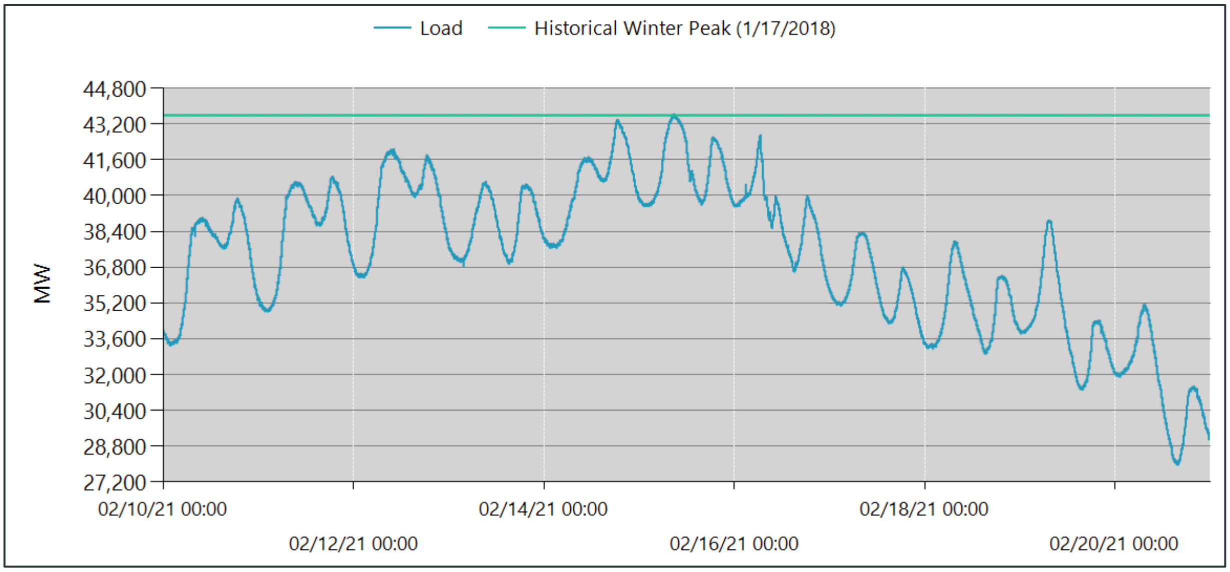

Figure 7: SPP BA load and historical winter peak

LOAD FORECASTING

The projected non-coincident peak load forecasted leading into the 2020-2021 winter season was approximately 43,700 MW. During the 2021 winter weather event, the SPP BA experienced a coincident peak demand of 43,661 MW. During this event, the highest forecasted day-ahead peak load was close to 46,000 MW while midterm forecasts indicated peak loads as high as 47,000 MW for Feb. 16.

SPP's day-ahead load forecasts projected higher load levels than were observed in real time for much of the week of Feb. 15. A few factors may have contributed to this over-forecasting of system load, including:

- President's Day holiday Monday, Feb. 15.
- Public appeals and load management.
- Commercial customer reductions following system load-shed events.
- Winter weather including snow and ice caused abnormal load behavior due to school and work closures.

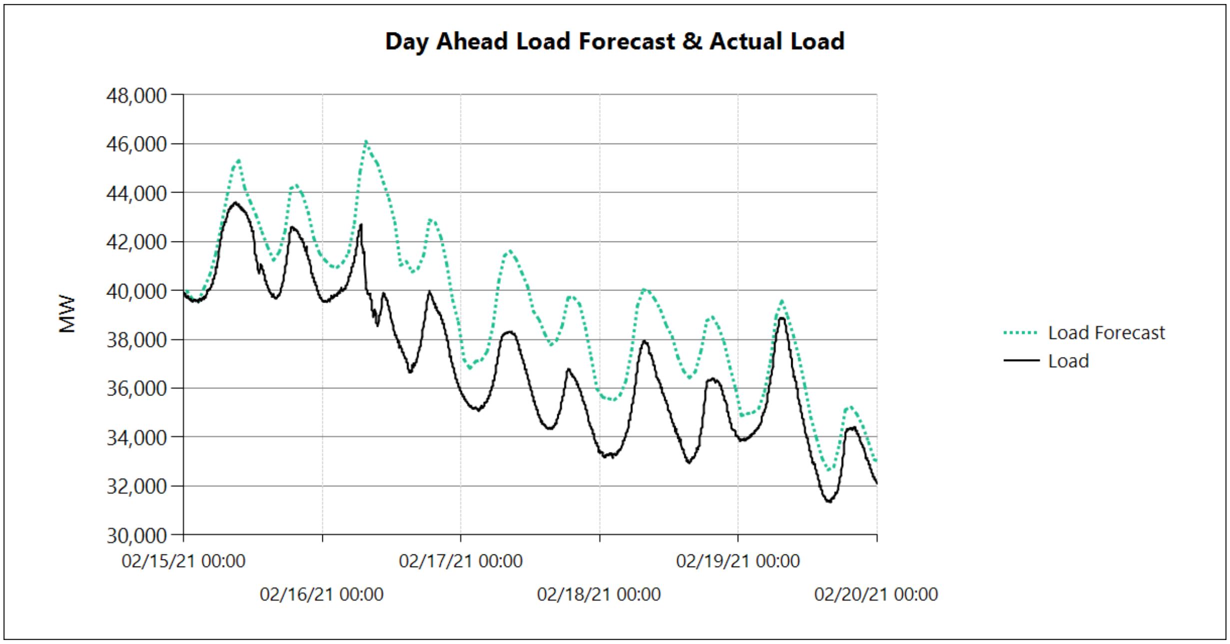

Figure 8: Day-ahead load forecast and actual load

WIND FORECASTING

Figure 9 shows the performance of the day-ahead wind forecast during the week of Feb. 15. The deviation observed late Feb. 15 through the morning of Feb. 17 was in part due to curtailments associated with system congestion.

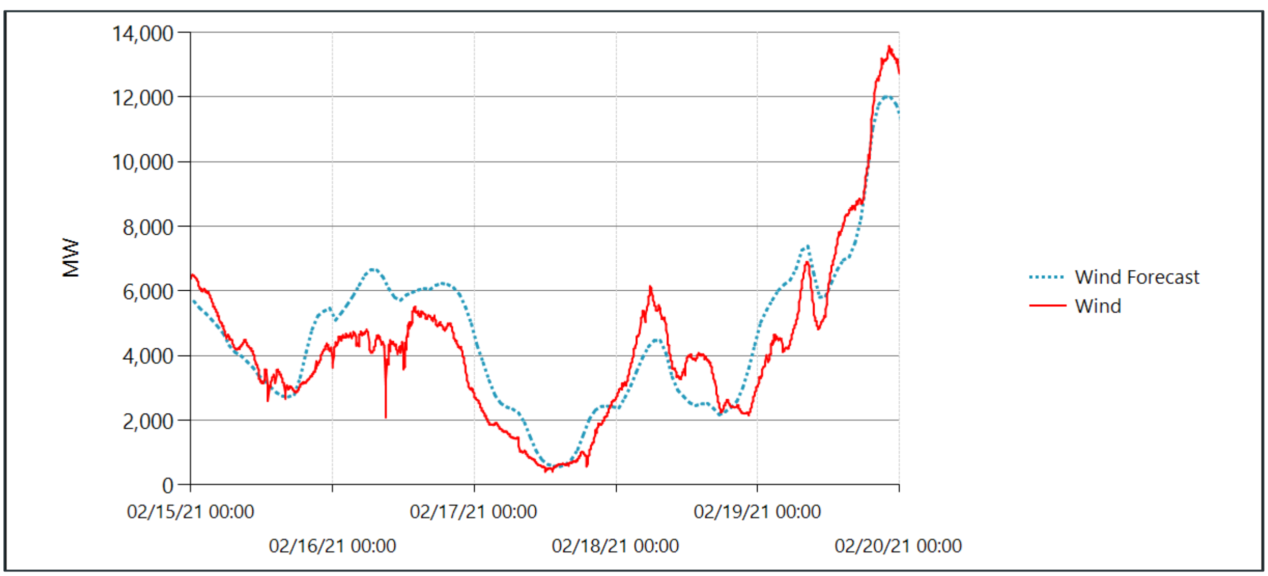

Figure 9: Day-ahead wind forecast and actual wind

MONDAY, FEB. 15: IN-DEPTH REVIEW

On Feb. 15, available capacity became insufficient to meet system demand. At 12:04 p.m., SPP directed 610 MW of load shed. Figure 10 shows online available generation combined with net scheduled interchange, load and Area Control Error (ACE). ACE is the instantaneous difference between a BA's scheduled and net actual interchange, taking into account the effects of frequency bias and correction for meter error. Near the time of load shed, when available generation fell below load, SPP experienced negative ACE indicating that the SPP BA was deficient and relying on unscheduled imports from the Eastern Interconnection to serve load. The morning outage and fail-to-start total of 3,790 MW at 10 a.m. represents capacity on resources that were in the current operating plan (COP) but failed to meet their commitment.

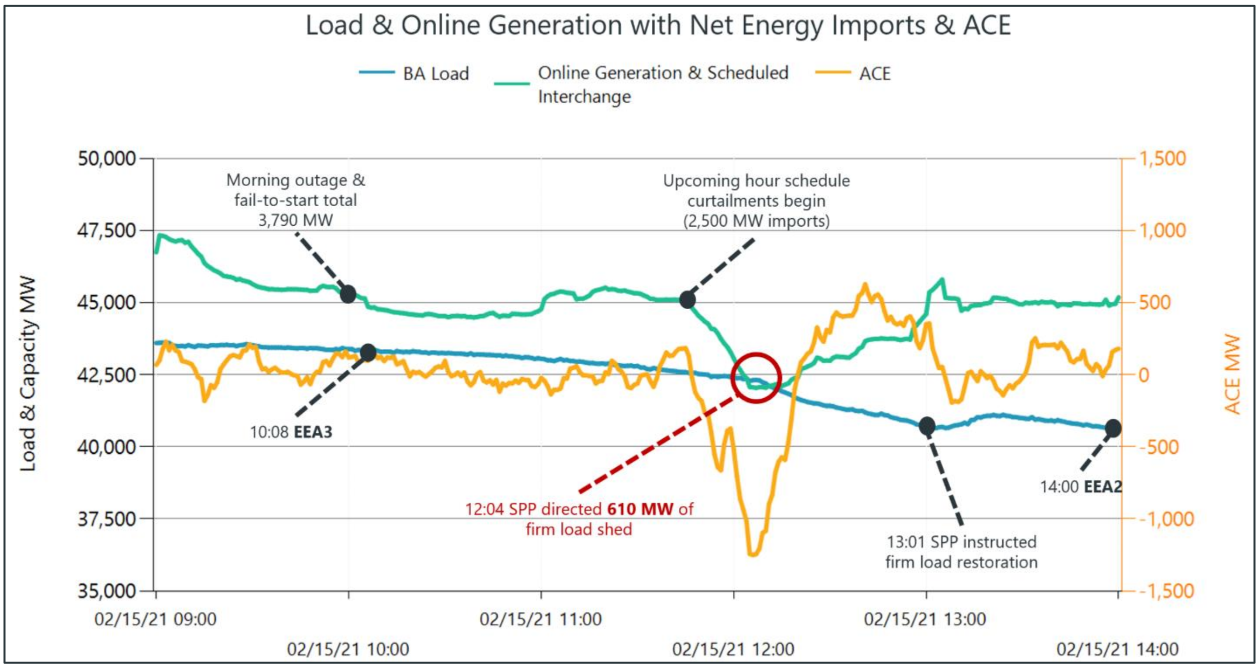

Figure 10: Load & Capacity with Area Control Error (ACE) (Feb. 15, 2021)

At the time of load shed, the real-time balancing market (RTBM) was completely deficient of reserves and dispatchable headroom. Capacity was present on resources that were manually reduced by out-of-merit-energy (OOME) instructions. This capacity was not deliverable due to transmission constraints and could not be utilized to serve load. Figure 11 shows the general areas of online capacity near the time of load shed Feb. 15. For this snapshot, a total of 648 MW of capacity was manually reduced. The red arrow indicates the region and direction of flow of the constraint that drove the manual reductions.

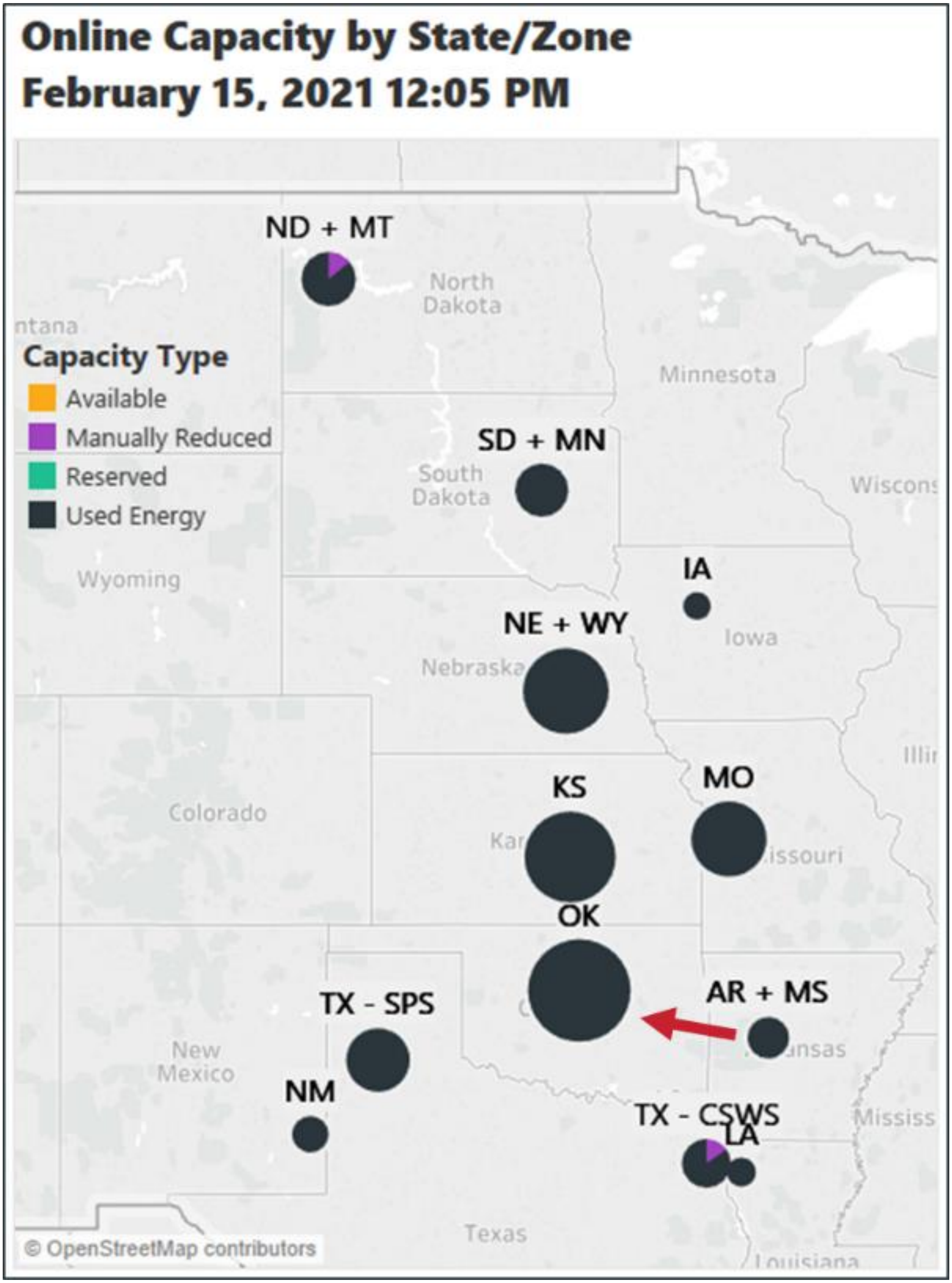

Figure 11: Map of online capacity (Feb. 15, 2021)

TUESDAY, FEB. 16: IN-DEPTH REVIEW

On Feb. 16, SPP directed a total of 2,718 MW of load shed: 1,359 MW at 6:44 a.m. and an additional 1,359 MW at 7:17 a.m. SPP also initiated the curtailment of up to 287 MW of firm exports as a share of SPP firm load obligation interruption. SPP sent its first instructions to partially restore load at 9:32 a.m., and sent subsequent instructions to restore the remainder of load at 10:07 a.m., effectively indicating that all load effected by the load-shed instructions could be returned to service. Figure 12 illustrates load and online generation with net energy imports and ACE during the morning of Feb. 16.

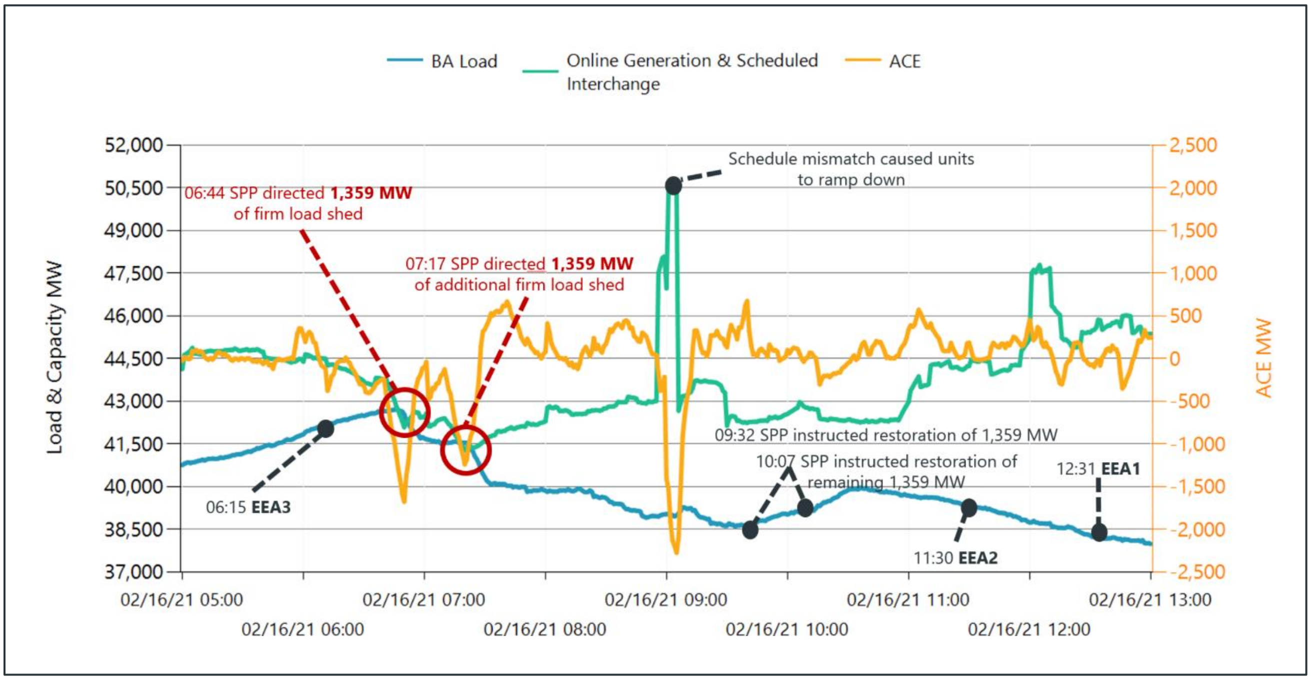

Figure 12: Load & Capacity with ACE (Feb. 16, 2021)

Near the time SPP issued load-shed instructions, the RTBM was unable to clear dispatchable headroom and was clearing only a small amount of reserves. As on Feb. 15, there was undeliverable capacity present on resources that were manually reduced. Figure 13 shows the general areas of online capacity near the time of load shed Feb. 16.

For this snapshot, a total of 1,862 MW was the manually reduced. Manual reductions were in place on several different resources to mitigate loading on various constraints across the SPP region. The red arrows indicate the locations and directions of flow for a few of the main constraints limiting generation.

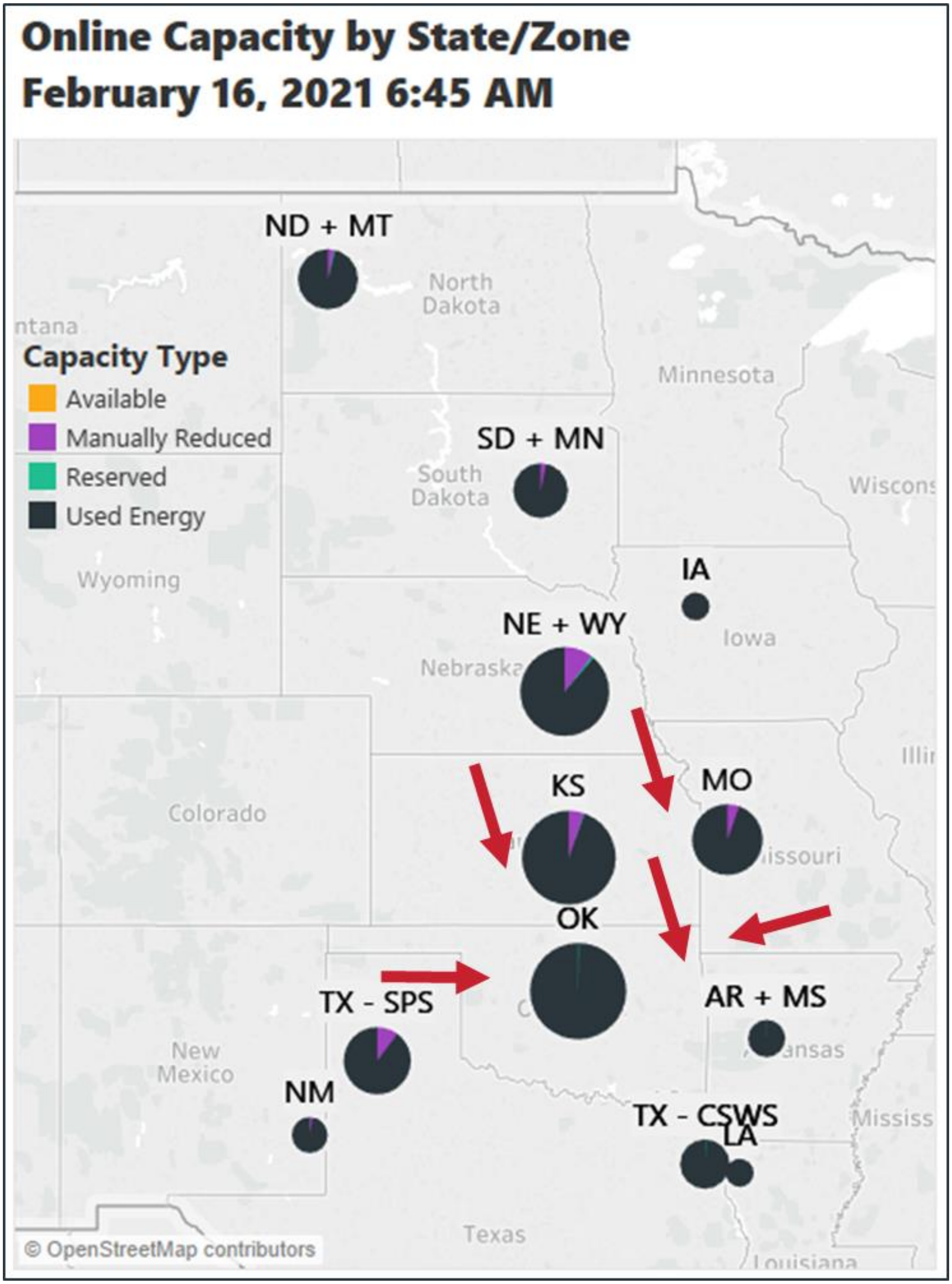

Figure 13: Online capacity map (Feb. 16, 2021)

WEDNESDAY, FEB. 17-FRIDAY, FEB. 19: OVERVIEW OF OPERATIONS

Although the worst of the event had passed, SPP continued to experience moments during Feb. 17-19 where its energy supply encroached on its ability to meet load and reserve requirements, requiring the declaration of heightened levels of Energy Emergency Alerts. Figure 14 shows generation with scheduled interchange and load, as well as load with contingency reserves.

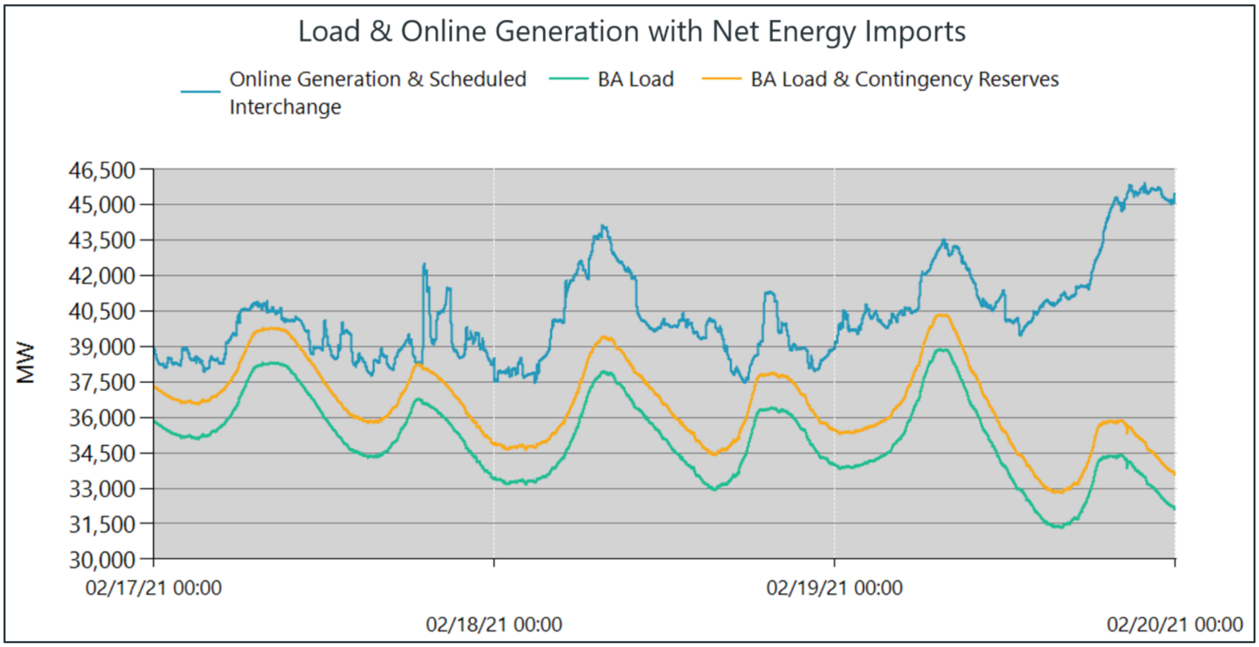

Figure 14: Load, Capacity and Load with Contingency Reserves (Feb. 17-19, 2021)

ANALYSIS OF OPERATIONAL AND MARKET PERFORMANCE

GENERATION AVAILABILITY AND FUEL ASSURANCE

During the 2021 winter weather event, all resource types experienced challenges ranging from operational reductions to total resource outages resultant from either frozen equipment or interrupted fuel supplies.

GENERATION ASSESSMENT PROCESS

SPP utilizes its Generation Assessment Process (GAP) to help ensure the SPP Balancing Authority's obligations can be met and to identify timeframes of allowable maintenance margin. The GAP methodology was reviewed and endorsed by the Operating Reliability Working Group. GAP is executed three times daily and results are posted publicly to ensure the most accurate information is available to generator owners/operators looking to schedule outages. SPP uses this information as part of its outage pre-approval process.

GAP creates a data set of actual historical values from the previous three years for all intervals plus and minus 15 days from the operating day. Maintenance margin calculation considerations include: total installed generation capacity (excluding variable energy resources), historical forced generation outages, current scheduled generation outages, historical wind performance, historical load and historical operating reserves.

CAPACITY AVAILABILITY

Based on historical averages over the past five years, SPP's market typically has about 55 gigawatts (GW) of available generation capacity[16] in February. As illustrated in Figure 15, that capacity dipped to roughly 35 GW during the week of Feb. 14, 2021. This 20 GW reduction from typical available capacity was primarily due to higher than usual fuel-supply deficiencies, wind-turbine freezing, and other challenges associated with operating equipment in extremely cold conditions such as frozen cooling towers, intakes, fuel lines, transmitters, etc. On Feb. 15 and 16, roughly 50% of forced generation outages cited fuel-supply issues as their cause.

[16] Includes reported available capacity of nonvariable resources and forecasted available energy from variable resources.

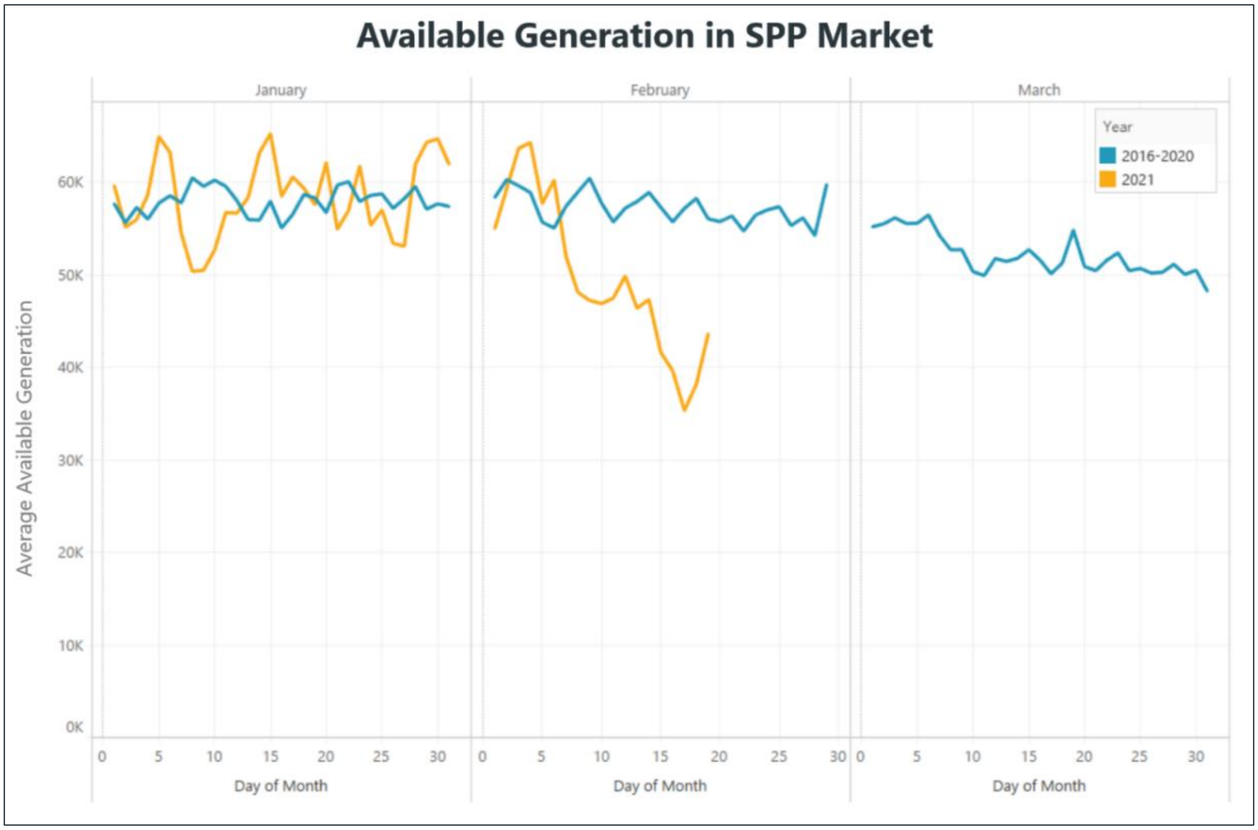

Figure 15: Available Generation in the SPP Market

FORCED OUTAGES

Figure 16 shows the forced generation outages in effect by fuel type during the two weeks preceding and the week of the event.

On Feb. 7, freezing rain and freezing fog moved into the central and southern regions of SPP (Kansas, Oklahoma and the Texas panhandle) and reduced available wind capacity due to ice buildup on turbine blades. Natural gas supply was limited due to extremely cold temperatures across the central U.S. [17]

SPP observed up to approximately 33 GW of forced outages during the week of the event, with an average of 30.5 GW of forced outages Feb. 16. Natural gas generation experienced an average of nearly 18 GW of forced outages during Feb. 16, and of those outages, nearly 75% cited lack of fuel supply as the cause.

[17] Members and market participants submitted CROW tickets indicating icing issues on wind resources and fuel supply concerns for natural gas generators.

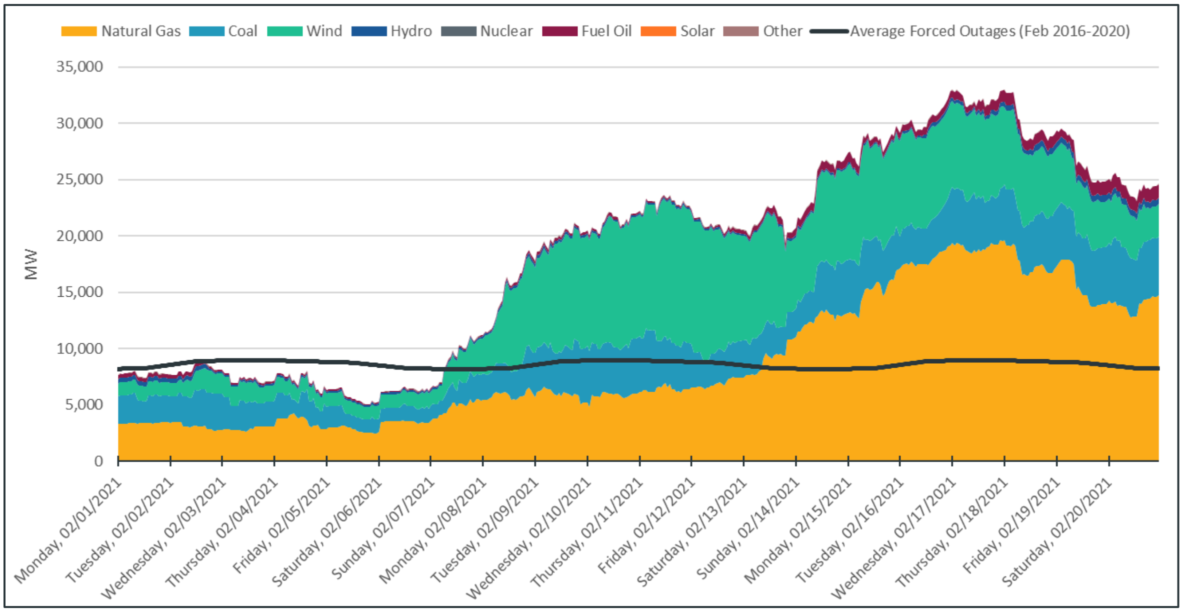

Figure 16: Forced generation outages as submitted in CROW by Fuel Type

Figure 17 shows the total generation unavailable due to forced outages, distinguished by the cause for the outage[18] as submitted into SPP's outage scheduling tool, Control Room Operations Window (CROW). On average, over 48% of all forced outages experienced during the week of the event were caused by fuel supply issues.

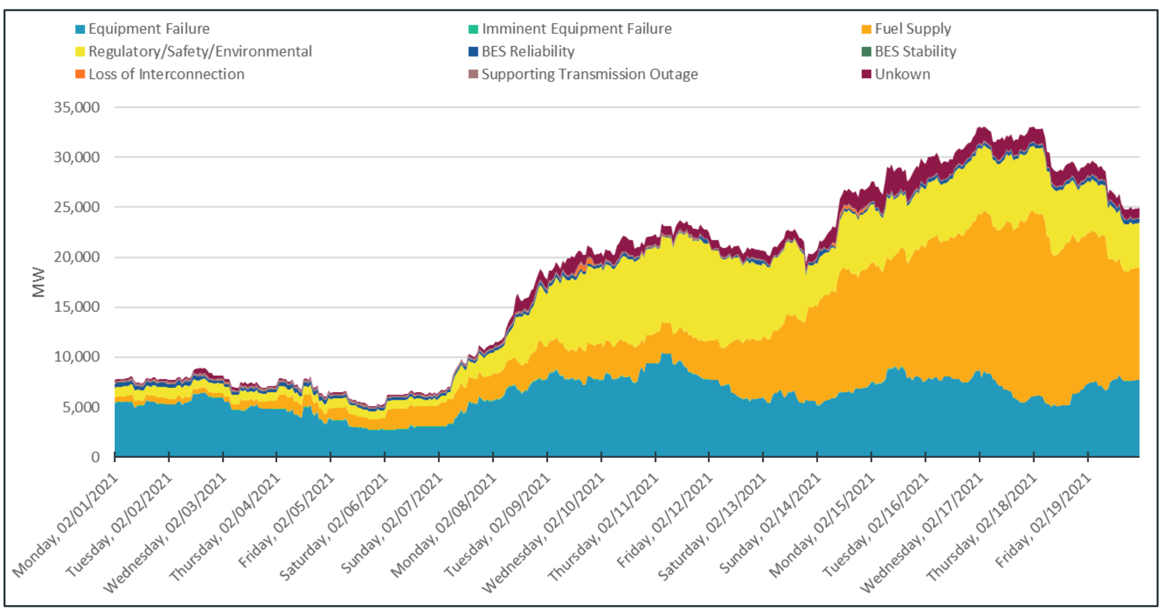

Figure 17: Forced generation outages as submitted in CROW by Cause Code

[18] Outages citing the regulatory/safety/environmental cause code consist largely of wind turbine outages due to cold weather and icing.

GAS SUPPLY

Figure 18, Figure 19 and Figure 20 illustrate natural gas, wind and coal generation that were unavailable Feb. 1-20 due to forced outages, distinguished by the associated cause as submitted in CROW. On average, approximately 72% of all forced gas generation outages experienced during the week of the event were caused by fuel-supply issues.

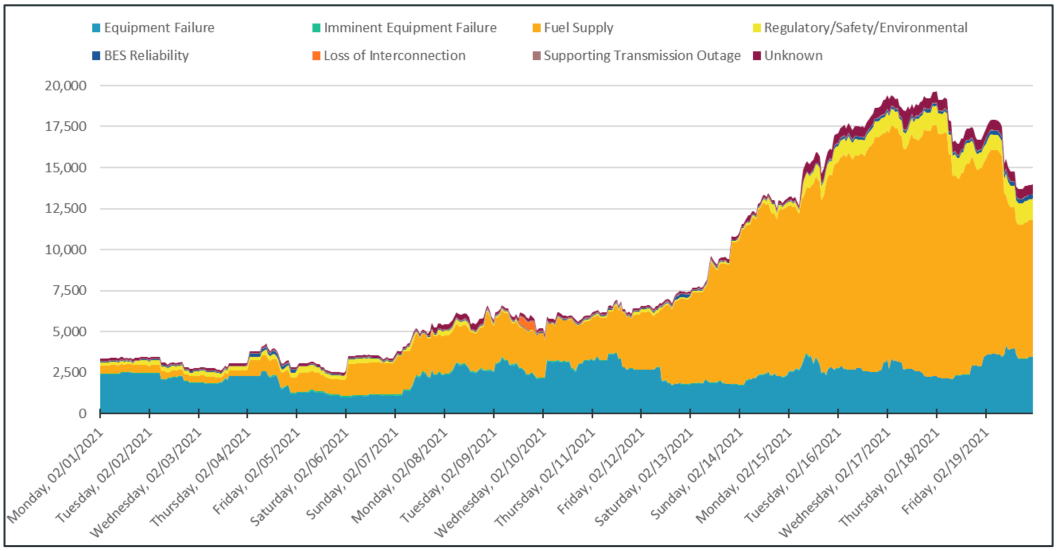

Figure 18: Forced natural gas generation outages as submitted in CROW by Cause Code

On average, approximately 51% of all forced wind generation outages experienced during the week of the event were caused by regulatory/safety/environmental issues, with 90% of those related to icing conditions.

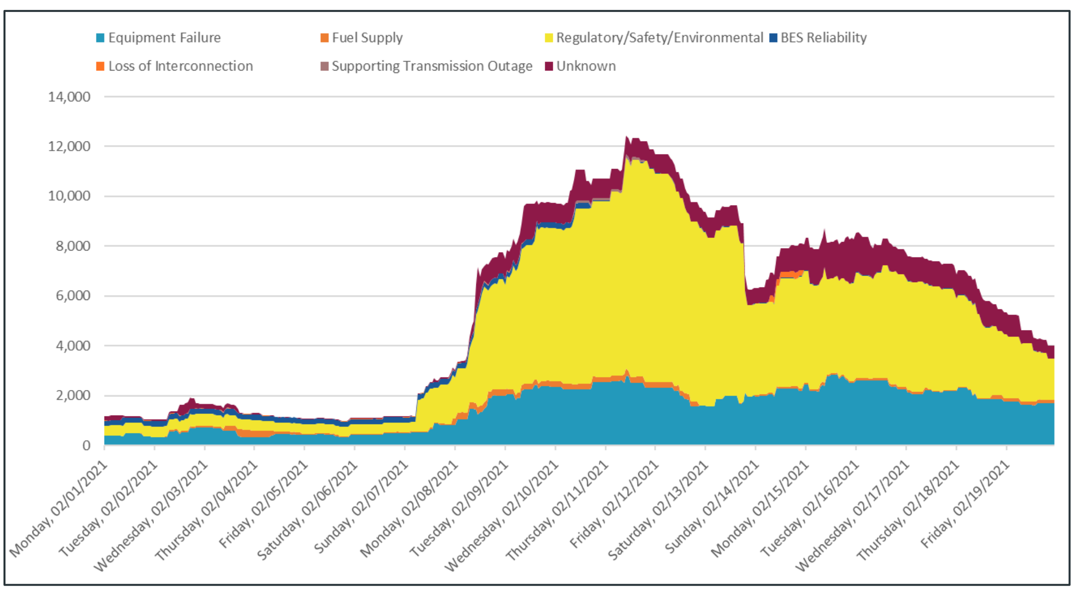

Figure 19: Forced wind generation outages as submitted in CROW, by Cause Code

On average, approximately 43% of all forced coal generation outages experienced during the week of the event were caused by equipment failure with another 28% caused by fuel-supply issues.

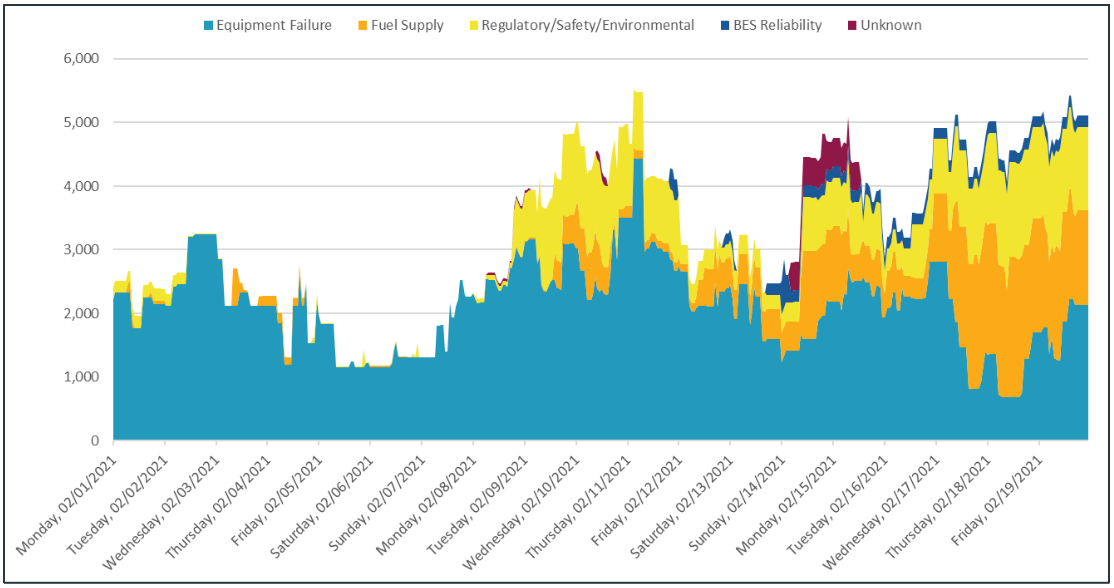

Figure 20: Forced coal generation outages as submitted in CROW, by Cause Code

GRID-SWITCHABLE RESOURCES

During the winter event, SPP coordinated with ERCOT regarding the use of grid-switchable resources that can operate in either SPP or in ERCOT. Three such resources are considered accredited capacity in SPP. These resources were committed and used as available to supply SPP load during the event when necessary to prevent service interruptions Feb. 15 and Feb. 16. SPP allowed the resources to supply load in ERCOT during times when they were not needed in SPP.

MUNICIPAL GENERATION, DEMAND RESPONSE AND BEHIND-THE-METER AVAILABILITY

There were municipal generators not directly connected to the SPP transmission system that were capable of operating but did not run during the event. SPP, as the BA, does not have a complete picture of all resources that may be available to assist during an energy emergency, and as a result some resources did not assist where needed. SPP did issue appeals to members to identify any resources not in the market that could assist with supplying load, but some were still not notified to come on-line.

CONCLUSIONS REGARDING FUEL ASSURANCE

The generating resources most impacted by the 2021 winter weather event were those fueled by natural gas.

Similar to electric power, the available natural gas fuel for consumption by electric generation and other customers is limited by the capacity of the supplies and transportation provided by the gas pipeline system. Extreme cold weather experienced across the SPP region resulted in natural gas procurement and deliverability issues. Increased demand for natural gas to heat homes combined with production issues attributed to wellhead freeze-offs resulted in a lack of access to natural gas by generator operators.

Upon review of information provided by the SPP Market Monitoring Unit (MMU), it is clear that extremely high natural gas prices were the primary driver of record high energy offers that exceeded the Federal Energy Regulatory Commission (FERC)-required offer cap of $1,000/megawatt-hour (MWh) for the first time in SPP's market history. On Feb. 15, SPP's market price reached an all-time high of $4,274.96/MWh in the day-ahead market (DAMKT). By comparison, the average price of energy in SPP's DAMKT for the entire year of 2020 was $17.69/MWh. Natural gas markets are not subject to price or offer caps, while electricity markets like SPP's are.

It is important to note that the electric industry does not have the ability, nor should it have the responsibility, to ensure a reliable, resilient and affordable natural gas supply. It is incumbent upon the natural gas industry to make the changes necessary to improve the supply of natural gas during extreme weather events. It is imperative that regulators understand the limitations of the electric industry in improving natural gas supply. Any new requirements to improve natural gas supply need to be imposed upon the gas industry and not the electric industry if this situation is to be improved.

The lack of access to natural gas was the largest contributing factor to the severity of the event, and establishes the need for better coordination and communication between the gas and electric industries moving forward.

In particular, additional early communication of potential severe conditions and the forecasted high demand for natural gas could have provided both industries with useful preparation time.

SPP has made several improvements related to gas-electric coordination in the past five years. In 2015, FERC issued Order No. 809 "Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities." In response to the order, in October 2016, SPP shortened the DAMKT timeline by 30 minutes and shifted the closing and posting times earlier in the day. In May 2020, SPP further reduced the DAMKT timeline by an hour. In addition, between 2016 and 2018, SPP coordinated with market participants to increase awareness of the need for additional detail in outage reporting, particularly fuel issues. SPP also recently implemented a multiday commitment and pricing forecast, which should provide generation-owning market participants with additional information related to generation needs. SPP

continues to seek opportunities for gaining efficiencies that better align the DAMKT with the gas day.

While SPP has focused on communication between the RTO and the market participant, SPP believes there should be a focus on increased communication between the RTO and the gas industry, i.e., communicating the need for gas and any deliverability issues of gas. SPP also believes it is important to understand the impacts of the development of natural gas fueled resources on the gas industry. SPP also thinks it is imperative to coordinate new projects with the gas industry, with the goal being to either increase the RTO knowledge of gas resource availability or increase the availability of gas to those same resources.

Certain system conditions may result in severe impacts to the electric or gas infrastructure. Better coordination is needed between the electric and gas industries to identify potential infrastructure contingencies within the RTO that could have a large impact on gas generators within the SPP region. The SPP Balancing Authority (BA) Emergency Operating Plan (EOP) does not presently include procedures for assessing and analyzing gas infrastructure reliability impacts on the SPP region during severe weather events, capacity emergency procedures, significant pipeline maintenance outages, pipeline operational flow orders, or during any other applicable conservative operations event.

FUEL ASSURANCE RECOMMENDATIONS

Table 11: Summary of recommendations to the board related to fuel assurance

#	TIER	CATEGORY	RECOMMENDATION
FA 1	1	Policy	Develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region.
FA 2	1	Assessment	Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events.
FA 3	2	Policy	Develop policies to improve gas-electric coordination that better inform and enable improved emergency response.

RESOURCE ADEQUACY, PLANNING AND AVAILABILITY

Figure 21 illustrates generation capacity in SPP. Nameplate capacity reflects the maximum amount of energy that all generation in SPP can produce based on equipment ratings.

Accredited capacity is the amount of generation capability owned or purchased by entities in SPP responsible for serving load that is expected to be available to meet peak demand. Energy production reflects how much energy was actually produced by generating assets in SPP during the most recent year.

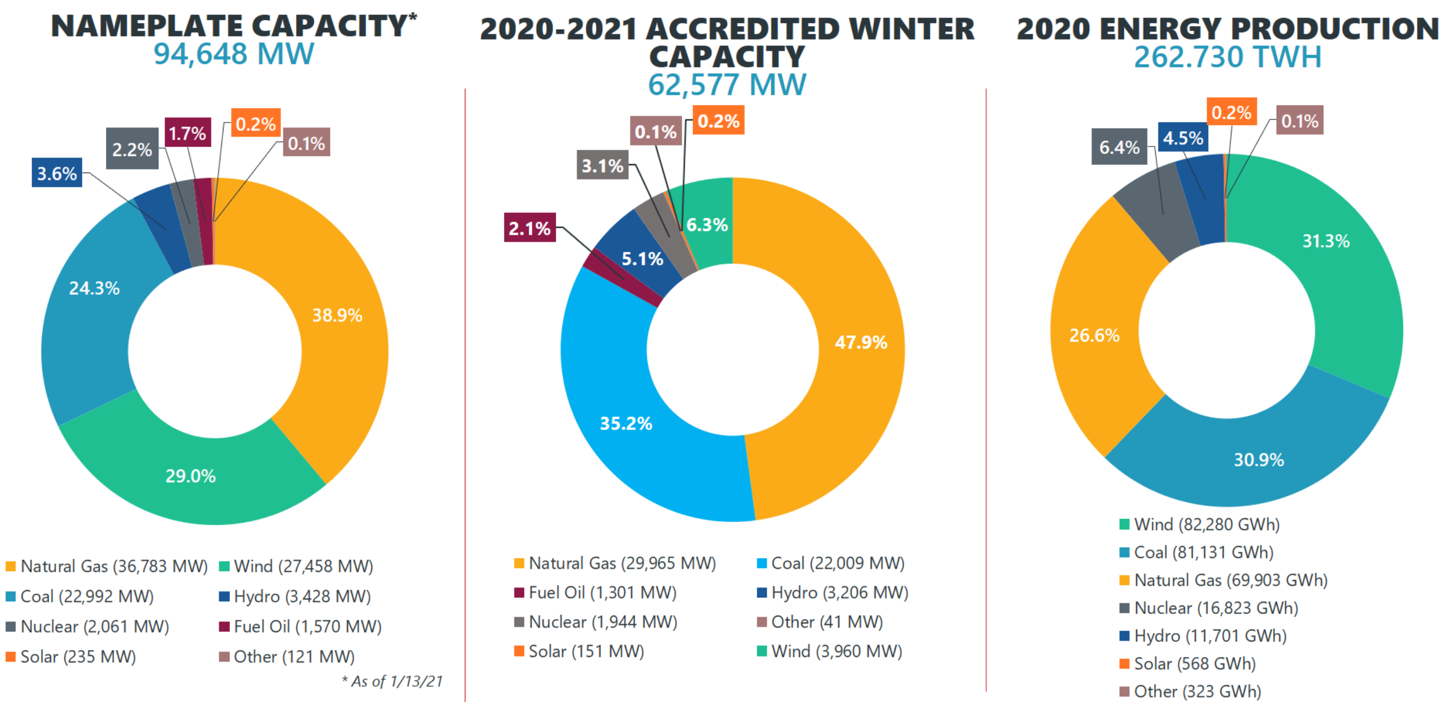

Figure 21: SPP generating capacity overview

During the periods on Feb. 15 and 16 when SPP declared an EEA 3, approximately 42% of nameplate capacity was available on average. The total amount of generation available during these time frames constituted approximately 65% of SPP's accredited capacity, with 87-88% of that available generation provided by accredited resources.[19]

[19] Each year, SPP verifies the specific amounts of each generating resource owned by load-responsible entities in SPP that are accredited for capacity purposes. During the event, generation available to SPP consisted of both accredited capacity resources and those that are not accredited. For these numbers, available generation represents the total economic maximum capability of online generation resources.

Figure 22 shows the status of generation capacity in SPP, distinguishing capacity that was on outage, unavailable and available. It also shows the used energy.

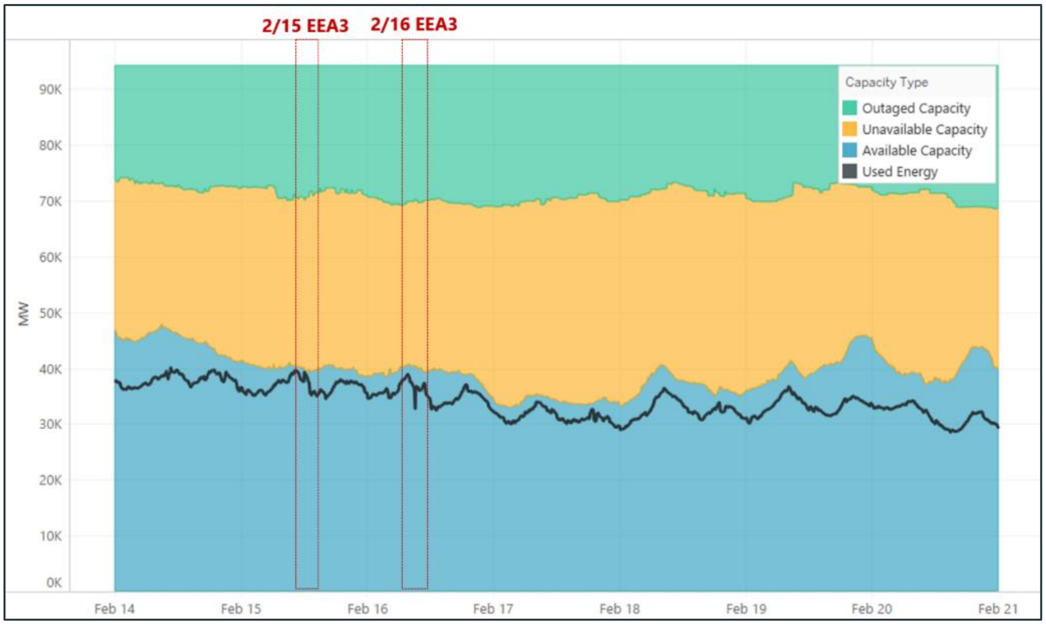

Figure 22: Total generating capacity in SPP

Considering only wind generation, 12-16% of nameplate capacity was available on average during the EEA3 events. The total amount of wind energy produced on average during these time frames constituted approximately 79-101% of accredited wind capacity, with 43-54% of that energy provided by accredited resources. This is illustrated below in Figure 23.

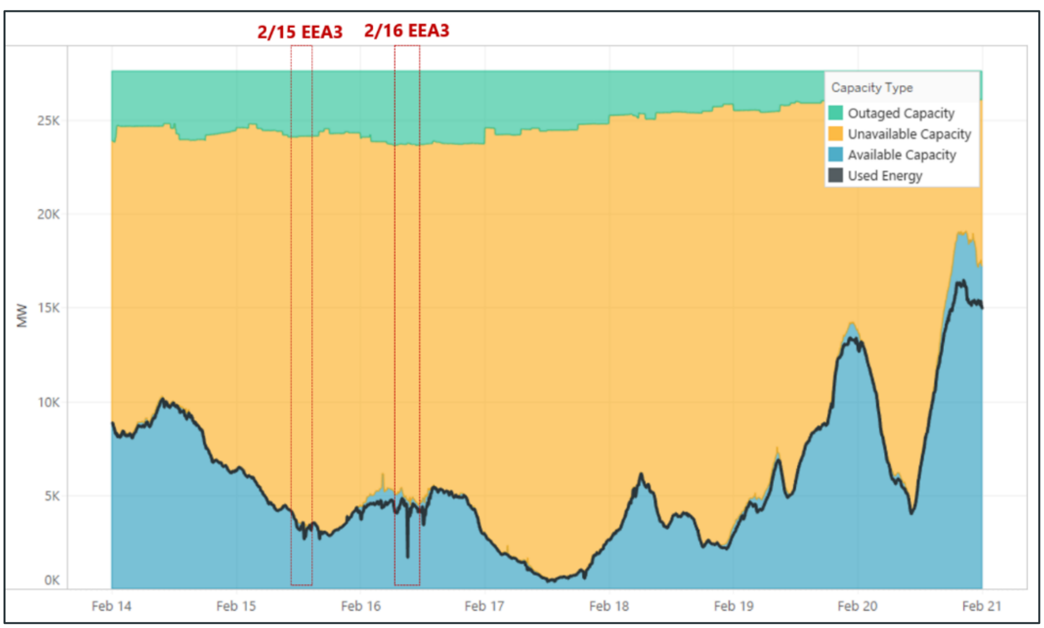

Figure 23: Total wind generating capacity in SPP

Regarding coal generation, about 77-79% of nameplate capacity was available on average during the EEA3 events. The total amount of coal energy produced on average during these time frames constituted approximately 87-89% of accredited coal capacity, with 98% of that energy provided by accredited resources. This is illustrated below in Figure 24.

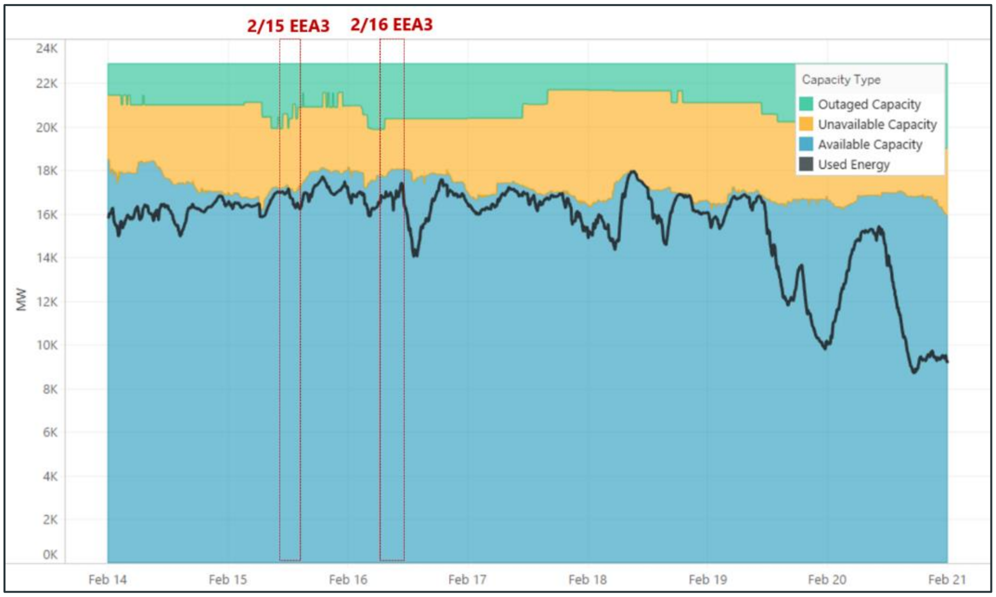

Figure 24: Total coal generating capacity in SPP

Regarding gas generation, about 34-37% of nameplate capacity was available on average during the EEA3 events. The total amount of gas energy produced on average during these time frames constituted approximately 40-45% of accredited gas capacity, with 95% of that energy provided by accredited resources. This is illustrated below in Figure 25.

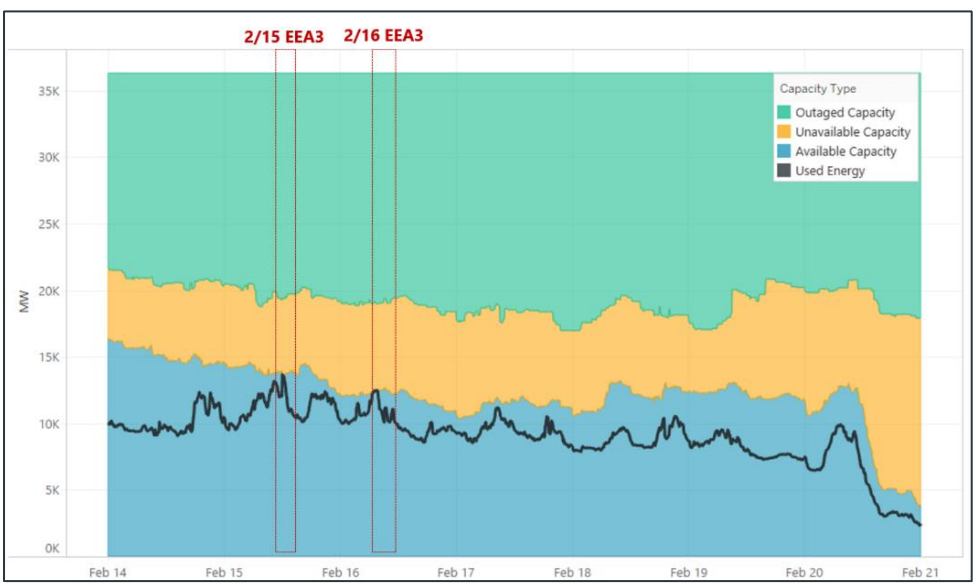

Figure 25: Total gas generating capacity in SPP

The following graphs compare available generating capacity with historical accredited capacity in February. The historical data set includes available generating capacity from each February of years 2014 through 2020. The shaded background indicates the total accredited amount of capacity that was applicable during February 2021.

The accredited value applicable to the 2020-2021 winter season is 62,577 MW for resources registered in the SPP market. The total accredited capacity used to meet resource adequacy requirements was 65,174 MW, which includes behind-the-meter generation not registered in the SPP market and firm imports to the SPP BA.

In the following graphs, available generating capacity for wind and solar is equivalent to the real-time dispatch amounts, while the generating capacity for all other fuel types relies on the real-time economic maximum limits for units that were not on outage. The economic maximum limit is the uppermost limit set in the resource market offer for which a resource can operate to without moving into emergency ranges.

Accredited capacity amounts used in these graphs are based on market resources only.

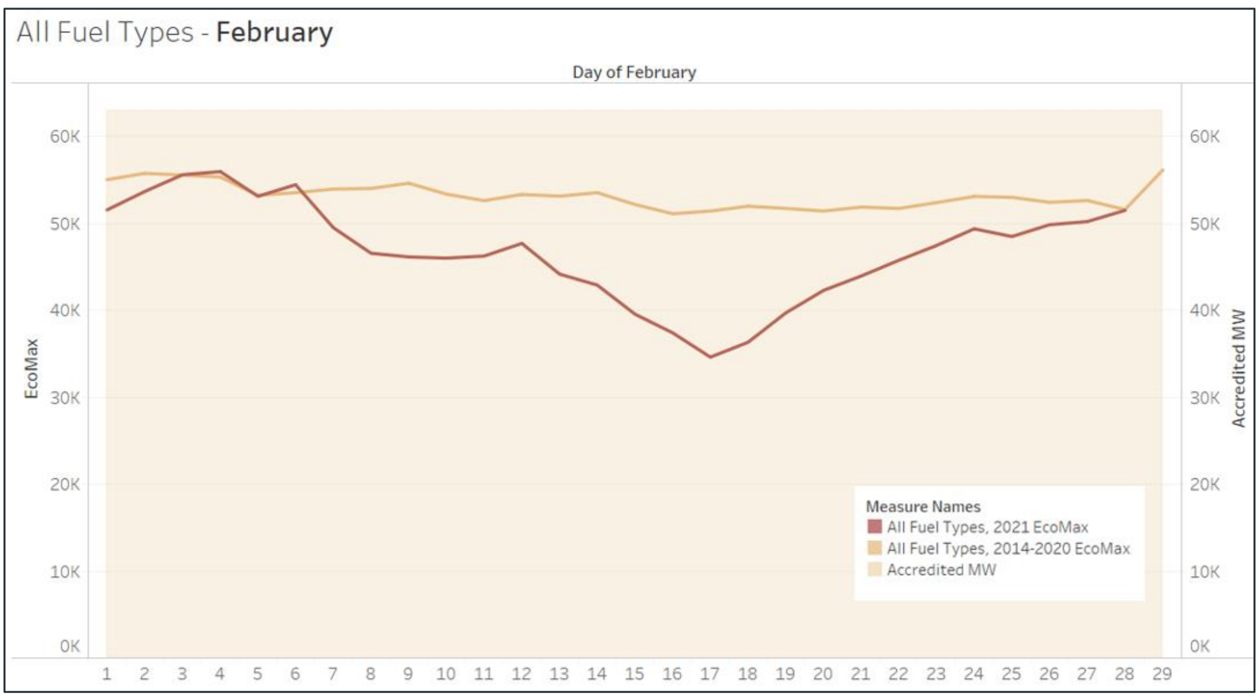

Figure 26: February 2021 available capacity as compared to prior year average

Wind availability was variable during February 2021. A significant icing event began Feb. 7, which contributed to the sharp decline in availability, as shown in Figure 27 below. Available capacity for wind is set to the real-time market dispatch of wind resources.

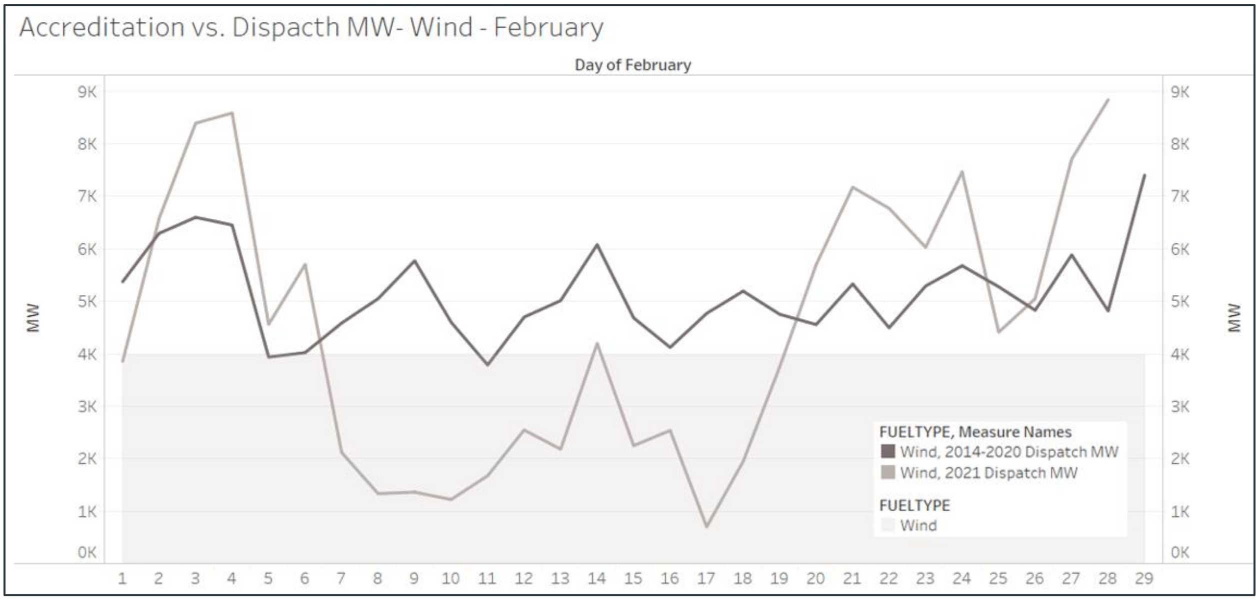

Figure 27: February 2021 available wind capacity as compared to prior year average

Coal availability for February 2021 fell roughly 2 GW below prior years. Available capacity for coal, shown in Figure 28, is based on the real-time economic maximum for units not on outage.

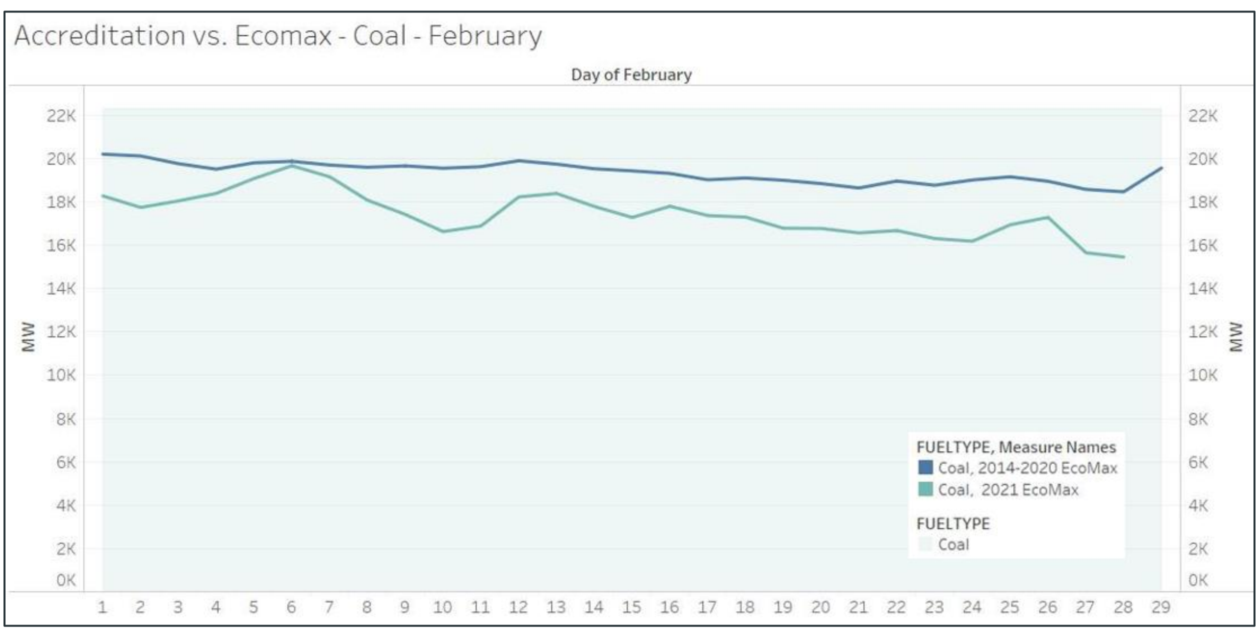

Figure 28: February 2021 available coal capacity as compared to prior year average

Gas generation availability dipped substantially during the week of Feb. 14. In Figure 29, available gas capacity is set to the real-time economic maximum for units not on outage.

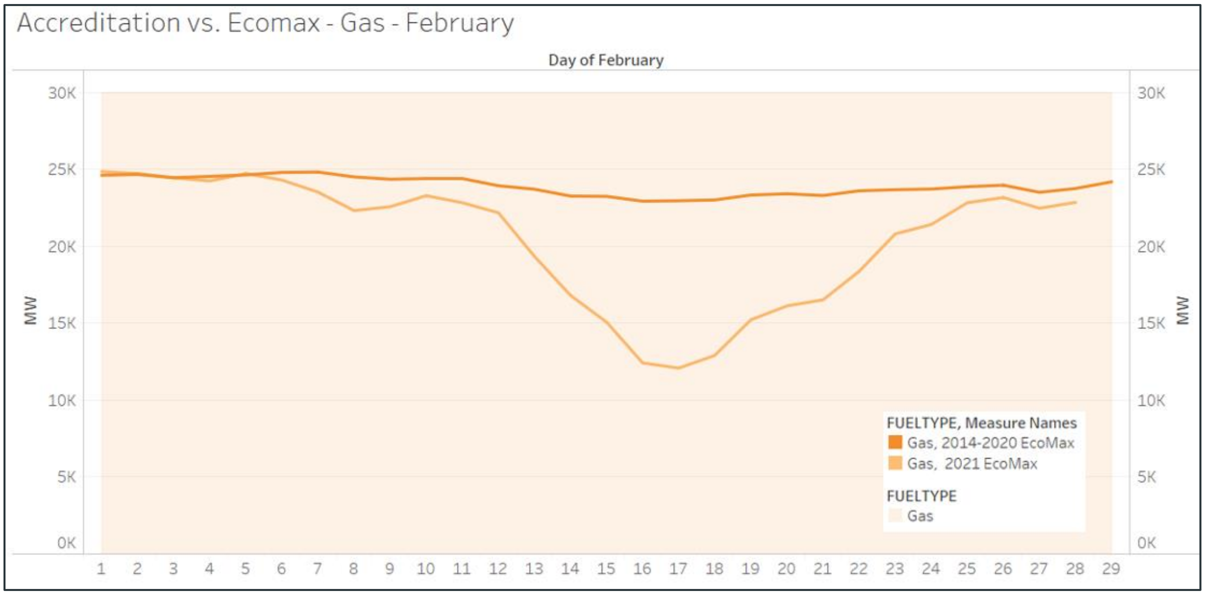

Figure 29: February 2021 available gas capacity as compared to prior year average

CONCLUSIONS REGARDING RESOURCE PLANNING AND AVAILABILITY

The 2021 winter weather event highlighted weaknesses of the components of the supply-side of the grid.

All forms of generation were stressed, and there were outages across all generation types. The event struck during a time of change in the way energy and capacity are supplied in the region. The event highlighted the need to further assess SPP's ability to reliably operate the system with the increased use of intermittent resources and further reduction of base-load resources. As the resource mix has changed and is expected to continue to evolve, the way resource adequacy has been determined in the past does not appear adequate to meet the needs of the future.

Accreditation values and capacity requirements based on summer assumptions do not adequately portray the amount of capacity that can be relied upon and needed during other critical seasons.

Summer peak assessments cannot accurately determine the needs of a severe event in the winter. Fuel supplies are under different constraints, wind and solar patterns are different, and the ability of a generator to start can vary markedly. Because of this, SPP needs to have a better understanding of the strengths and weaknesses of all resource types during times other than summer. SPP should also assess the importance of diversity in supply and demand resources

and how these resource types interact with each other during periods of stress and assess cost effective ways to ensure that reliability is able to be maintained. The 2021 winter weather event underlined the importance of this work.

Historically, data has shown the average economic max capacity for conventional resources in SPP's Integrated Marketplace is lower than the accredited capacity submitted for resource adequacy purposes. SPP and the SAWG have diligently worked over the past two years to begin implementing more robust and reliable accreditation methodologies across all resource types. This effort started with the implementation of the effective load carrying capability (ELCC) methodology for wind, solar and battery storage starting with the 2023 summer season.

Additionally, there is an effort underway to evaluate a form of performance-based accreditation for conventional resources. This important work should continue with extra emphasis and with focus on seasonal expectations.

Currently, SPP resource adequacy policies place an obligation on each load-responsible entity (LRE) to meet its individual winter season noncoincident demand plus the planning reserve margin (PRM) requirement. The winter season PRM is based on a Loss-of-Load Expectation (LOLE) study that is performed every two years and determines the appropriate amount of capacity needed to reliably maintain the one-day-in-10-year standard.

While this study encompasses the whole year, its focus is on the summer peak season, for which the majority of loss of load in the SPP region is analyzed to occur during the summer timeframe. Therefore, the PRM applied to the winter season is based on the summer season demand values. Expectations of abnormally excessive generation outages during extreme weather events (cold, heat, drought, flooding, atmospheric conditions) are not currently included in the planning study with a higher than previously experienced occurrence rate.

Currently, LREs that schedule planned outages during the summer season are not allowed to count that capacity toward their resource adequacy requirement. As risk of loss of load is seen to expand beyond the summer season into the winter season and potentially into the shoulder months, policies need to address how accredited capacity may be counted in the summer and winter seasons with planned outages taken into account.

RESOURCE PLANNING AND AVAILABILITY RECOMMENDATIONS

Table 12: Summary of recommendations to the board related to resource planning and availability

#	TIER	CATEGORY	RECOMMENDATION
RPA 1	1	Assessment	Perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix.
RPA 2	1	Policy	Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives, that ensure sufficient resources will be available during normal and extreme conditions.

EMERGENCY RESPONSE PROCESSES AND PLANNING

SPP's emergency response processes are detailed in the SPP BA Emergency Operating Plan (EOP)[20]. This plan includes procedures for issuance of load-shed instructions. Load shed is a controlled interruption of electric service to end-use customers under an EEA level 3 when all other means of supplying internal load have been exhausted, or to maintain area control error (ACE) so as to not jeopardize the reliability of the bulk electric system. Per the SPP Operating Criteria and Appendices[21], the Reliability Communications (R-Comm) tool is the primary means of communication for responsible entities to receive, acknowledge and carry out load-shed instructions issued by the SPP BA.

SPP staff performs load-shed tests regularly. SPP also conducts annual training for SPP operators on energy emergency alerts and load shed for the SPP BA, including the use of the R-Comm tool.

Each member transmission operator (TOP) is responsible for developing, maintaining and testing its own emergency response plan and for carrying out load-shed instructions pursuant to those plans.

LOAD SHED DURING SYSTEM CONGESTION

During load shed on Tuesday, Feb. 16, 2021, there were locations where generation was curtailed at the same time load was being shed on the same side of constraints. Considering that load shed can be considered a very expensive demand response unit, it may not be optimal to dispatch a high-cost unit up at the same time a lower-cost unit is being dispatched down in the same area. Pro-rata curtailments are reasonable when there is no congestion on the system but could lead to excessive load shedding during times when there is congestion on the system.

DISTINGUISHING BETWEEN FIRM AND NONFIRM EXPORTS

SPP did not distinguish between exports that were firm (associated with a capacity or firm energy transaction) versus nonfirm energy during the EEA. The North American Electric Reliability Corporation (NERC) Reliability Standard EOP-011-1 Attachment 1 identifies that during an EEA level 1, "Nonfirm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed." During the event, SPP treated exports pursuant to their transmission service priority only without regard to the firmness of the energy that was associated with the transaction. SPP needs procedures and processes that clearly identify that curtailment is based upon the transmission service level for transmission curtailments and based upon the level of firmness of the energy for EEAs.

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[20] Revision 7.5 (Effective 09/30/2020), https://www.spp.org/spp-documents-filings/?id=34055
[21] Revision 2.2 (Effective 06/17/2019), https://www.spp.org/documents/60100/spp%20operating%20criteria%20and%20appendices%20v2.2.pdf

EMBEDDED ENTITIES AND LOAD-SHED PROCEDURES

SPP did not have an accurate representation of which embedded entities were contained within various transmission operator (TOP) footprints. Additionally, some TOPs did not understand the load-shed amount they were given included the total load connected to their transmission footprint and not just their entities' load. As a result, some entities may have not been included in the load-shed event and other entities may have had incorrect amounts of load shed requested of them.

LOAD RATIO SHARE FOR LOAD SHED

The load ratio share used to determine each TOP's share of the manual load-shed amount is based upon prior year energy use for a season. Some customers were proactive and voluntarily reduced their demand for electricity in response to public appeals or as part of an interruptible load program. The current paradigm does not recognize the contributions to the entire SPP region that these reductions provide. One way to recognize these contributions would be to calculate load ratio shares used for load shed based upon actual loads at the time of the event.

LOAD-SHED INSTRUCTIONS

On Feb. 16, 2021, SPP initiated a load-shed event for 1,350 MWs of BA load followed by a second load-shed event for an additional 1,350 MWs of BA load 33 minutes later. The result was confusion by several TOPs who were unsure if they had received a second load-shed instruction, or a secondary notification of the initial load shed instruction. SPP staff noted that the separate instructions were accompanied by unique R-Comm event IDs. Although a partial load restoration was not necessary, SPP was prepared to use the load-shed calculator if the need arose. There is an R-Comm enhancement underway that would allow for systematic processing of partial load restoration.

INTERRUPTION OF CRITICAL LOAD

During the load-shed events, there were concerns from TOPs that natural gas compressor station loads may be curtailed, exacerbating the fuel shortage issue and causing a need for additional load shed.

There are additional concerns that these critical loads do not have adequate backup plans to continue operating in the event of a loss of interconnection to the grid such as gas fired compression. Reliance upon the electric grid to power compressors will lead to interruptions in service due to other forced outages not initiated by the TOP.

CONCLUSIONS REGARDING EMERGENCY RESPONSE PROCESSES AND PLANNING

SPP's and its members' emergency response processes, including use of load-shed procedures, were effective in preventing uncontrolled, more significant loss of load but could be improved to increase effectiveness and appropriateness of load-shed actions.

EMERGENCY RESPONSE PROCESSES AND PLANNING RECOMMENDATIONS

Table 13: Summary of recommendations to the board related to emergency response processes and planning

#	TIER	CATEGORY	RECOMMENDATION
ERP 1	2	Assessment	Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations.
ERP 2	2	Action	Implement improvements to load shed processes to be developed by the Operating Reliability Working Group (ORWG), such as: • Utilize real-time load values when determining load-shed ratio shares. • Train and drill on multiple overlapping load-shed instructions. • Perform a detailed review of models used to determine load-shed ratio shares. • Develop and document procedures and processes to address the timing and responsibility of curtailing exports before and during a load-shed event.
ERP 3	2	Policy	Develop a policy to ensure TOP emergency response and load-shed plans have been reviewed, updated and tested on an annual basis to verify their effectiveness, with attention to critical infrastructure.

OPERATOR TOOLS, COMMUNICATION AND PROCESSES

During Feb. 15 and 16, 2021, there were constraints loaded above 115% of their emergency ratings post-contingent. SPP has processes that instruct staff to perform a cascading analysis for post-contingent loading levels above 115%. Although this is good practice, the results of these analyses are not available for TOPs for review.

When SPP issues out-of-merit-energy (OOME) instructions, there is not a consistent method to inform SPP real-time operations personnel when conditions have changed that will permit the release of all or part of the OOME instruction. In addition, there were locations where low-cost resources were manually dispatched down at the same time high cost resources were brought online at the same BUS.

There were times when the market was unable to solve congestion due to the violation relaxation limit (VRL) being less than the cost to move resources. This was exacerbated by an increase in the maximum energy price, but when the market doesn't have enough resources to balance load with resources and interchange and resolve congestion, the congestion will remain. It may be beneficial in the long run to identify pockets where load reductions would be the least costly to resolve congestion once the congestion has not been corrected for several market iterations. In addition, it may not be readily apparent to TOP operators the Market Clearing Engine (MCE) is not respecting this constraint because the cost to solve the congestion is greater than the VRL.

The R-Comm tool performed well throughout the event. Communications were timely and the information provided to the TOPs via R-Comm was timelier than other methods of communications. Especially when messages require acknowledgement, there is a high degree of confidence the message will be received. When R-Comm was originally rolled out, there were concerns TOP operators may not pay attention to the messages that were sent over R-Comm alone. This event demonstrates that R-Comm is an effective mechanism for real-time operations communications between SPP and its TOPs. At times, the additional blast calls and satellite phone calls served as more of a distraction rather than an enhancement of the communications process. These communications mechanisms can serve as a backup means of communication, but are not needed when R-Comm is functional.

While TOPs have avenues to view some SPP systemwide data, the paths are disjointed, and the data available does not provide a complete system overview. Offering TOPs a single tool that provides a complete system overview would help TOPs better understand the state of the SPP region in real time. Additionally, conservative operations alerts can have many different interpretations, ranging anywhere from business as usual to TOPs canceling and recalling outages. Associating conservative operations alerts with defined alert levels would give more meaning to the conservative operations alerts and help members react to the alerts accordingly.

The pre-event calls between SPP and the Operating Reliability Working Group (ORWG) members provided valuable communications on the situation unfolding. There were others in SPP who could have benefited from this information, and SPP could have benefited from others having this information firsthand. However, there was no readily available contact list that SPP could

utilize to quickly organize a conference call. Furthermore, it would be advantageous for SPP to develop email lists that utilize distribution lists developed by each operating entity for different types of notifications. SPP needs to identify whether each group may contain merchant employees or not. This will be determined by the type of information sent to each list. Having the entities maintain internal distribution lists with SPP just sending information to a single list, will place responsibility and control of who receives the messages within the membership. This may result in more up to date distribution lists.

CONCLUSIONS REGARDING EMERGENCY RESPONSE PROCESSES AND PLANNING

SPP's tools, communications and processes were largely effective during the winter weather event but should be improved to increase effectiveness and awareness among critical participants.

OPERATOR TOOLS, COMMUNICATION AND PROCESS RECOMMENDATIONS

Table 14: Summary of recommendations to the board related to operator tools, communications and processes

#	TIER	CATEGORY	RECOMMENDATION
OTCP 1	2	Action	Develop or enhance the tools, communications and processes identified by the ORWG and needed to improve SPP and stakeholder response to extreme conditions, such as: • Enhance real-time cascading analysis studies and post results. • Develop tool(s) to increase operator awareness of Out of Merit Energy (OOME) instructions. • Enhance and expand the use of R-Comm.[22] • Create a reliability dashboard to improve situational awareness for operators. • Utilize member-maintained distribution lists for communications purposes. • Develop a process to update operations management during extreme conditions.

[22] R-Comm is the Reliability Communications tool, the primary means of communication for responsible entities to receive, acknowledge and carry out load-shed instructions issued by the SPP Balancing Authority.

MARKET DESIGN

PRICING DURING EEA EVENTS

PRICE RESPONSIVE LOAD AND PRICING DURING LOAD-SHED EVENTS

During the Feb. 15 and 16 load-shed events, SPP observed intervals during which locational marginal prices (LMPs) dropped below $100. These lower LMPs may have sent the wrong signal to the market during a time when energy was needed so the load could be restored. The price formation and incentives for continued energy delivery may be improved during these times by modifying the pricing structure during load-shed events to continue to reflect prices associated with serving the desired amount of load and not the reduced amount of load due to the load shed. Incentives for price-responsive load in SPP's market may also improve the price formation during these times by allowing the market to determine load reduction based on offers and congestion.

VIOLATION RELAXATION LIMITS AND DEMAND CURVE PRICING DURING EMERGENCY CONDITIONS

During the event, SPP also observed instances where transmission constraint violations occurred due to energy offer prices exceeding the VRL price. Energy prices offered above the highest VRL price can overpower the cost to re-dispatch around transmission constraint that leads to these violations. The current VRL prices were set based on analysis using the FERC approved $1,000 energy offer cap. However, during the 2021 winter weather event or other emergency conditions when energy offers are greater than $1,000, these VRL prices may not be appropriate.

SPP also observed violations on the spinning reserve requirement and resource ramp rate constraints. Spinning reserve and resource ramp rates are priced as VRLs. These VRL prices may not provide transparent prices during events such as the 2021 winter weather event. SPP may desire to change these two requirements to be demand curves instead of VRLs, but this also means SPP must determine the appropriate price for these demand curves.

APPLICATION OF EMERGENCY LIMITS

During the 2021 winter weather event, system conditions dictated SPP release maximum emergency capacity operating limits in accordance with the prescribed language in both the Integrated Marketplace Protocols and Attachment AE of the SPP Open Access Transmission Tariff. This release of maximum emergency capacity operating limits allowed for DAMKT dispatch values up to these limits for a number of resources, including some VERs. Additionally, while the DAMKT used emergency capacity operating limits as prescribed by the governing documents, in real time, emergency capacity operating limits were not used due to operational concerns. This raises the question as to whether or not the application of maximum emergency

capacity operating limits is appropriate and provides the value SPP and the membership envisioned during the design of the Integrated Marketplace.

DAY-AHEAD MARKET AND MARKET-TO-MARKET

One purpose of SPP's DAMKT is to give generators and LSEs a means by which to schedule activities sufficiently prior to their operations. This is typically based on a forecast of their needs and consistent with their business strategies. Although SPP committed many resources for reliability reasons, rather than through the usual DAMKT process, the DAMKT continued to give reasonably accurate predictions of the operating day. The exceptions were Feb. 13 and 14, 2021, which SPP repriced after-the-fact.

While the DAMKT looks ahead and the market-to-market process focuses on real-time, they are traditionally both views as tools to further enhance economic benefits of the Integrated Marketplace, not to enhance reliability. During the 2021 winter weather event, their reliability benefits were evident. By committing resources through the DAMKT process, it reduced the dependency of capacity generation being required to be committed through the reliability unit commitment processes. During the event, this was critical, as it was even more vital to the overall capacity needs to the SPP footprint to ensure all available generation could be utilized appropriately.

Similarly, the market-to-market process's ability to use the combined generation fleet of both SPP and MISO to mitigate constraints further displayed its reliability benefits. The process allowed for a more systematic response than the alternative methods such as transmission loading relief (TLR). It also provided a mechanism for increased real-time communication on how mitigation of internal RTO constraints with internal generation would impact the neighboring RTO's constraints.

MULTIDAY RELIABILITY ASSESSMENT

SPP's Integrated Marketplace design consists of numerous unit commitment processes beginning with the multiday reliability assessment (MDRA), continuing with the DAMKT and concluding with the day-ahead, intraday and short-term reliability unit commitments (RUC). The purpose of the MDRA is to evaluate the reliability-based need to issue instructions to start to resources that cannot be committed in the day-ahead RUC because of their long lead time as well as committing resources as part of conservative operations, as outlined in the SPP BA EOP.

As part of conservative operations, SPP issued resource commitments of various lead times well in advance of the DAMKT to give early notice that the resources would be needed and to allow more time to procure the appropriate amounts of fuel needed for the duration of the event. Although similar commitments have been made as part of conservative operations in the past, the scale during this event was unprecedented and has allowed SPP to assess the processes, procedures and governing language associated with the MDRA process.

DISTPATCH TARGET ADJUSTMENT PROCESS

During the 2021 winter weather event, the SPP BA activated an operational tool downstream from the Real-Time Balancing Market (RTBM) clearing called Dispatch Target Adjustment (DTA). This tool lives in the emergency management system (EMS) application RTGEN. The DTA tool is typically used by SPP operations to balance the SPP region in times when the MCE is not functioning properly or not working at all.

During the 2021 winter weather event, the SPP BA used the DTA process to ensure its ability to balance the region and keep ACE in check due to insufficiencies in cleared operating reserves from the RTBM and due to uncertainty around the timing of curtailed tags from MISO. Notably, the RTBM cases continued to solve and approve, publishing new dispatches and LMP every five minutes. DTA takes the last solved and approved RTBM and adjusts the resulting setpoint as needed to chase the load using the marginal cost calculated in that RTBM. While the setpoint adjustments were generally in merit and updated as RTBM cases approved, there were many instances where resources were positioned out of merit and financially harmed.

MARKET DESIGN RECOMMENDATIONS

Table 15: Summary of recommendations to the board related to market design

#	TIER	CATEGORY	RECOMMENDATION
MKT 1	2	Policy	Develop and improve policies to ensure price formation and incentives reflect system conditions.
MKT 2	2	Action	Develop and implement market design and market related enhancements identified by the Market Working Group to improve operational effectiveness and ensure governing language provides needed flexibility and clarity, such as: • Improve the Dispatch Target Adjustment Process. • Enhance the Multiday Reliability Assessment Process.
MKT 3	2	Policy	Develop policies to ensure financial outcomes during emergency conditions are commensurate with the benefits provided.

TRANSMISSION UTILIZATION AND PLANNING

CONGESTION

Congestion describes a condition when usage of transmission facilities exceeds reliable operating limits. SPP and neighboring areas experienced very high levels of congestion during the winter event. Congestion particularly posed challenges, as an abnormally high number of transmission system constraints[23] experienced high loading. Many constraints were as much as 10-20% above their post-contingency operating limits, and some were near real-time operating limits. Primary contributors to system congestion during the focused period of Feb. 15-19 included, but are not limited to:

- Winter peak load levels.
- High import flows from neighboring systems into SPP.
- High export flows into ERCOT from SPP including schedules using firm transmission.
- MISO regional directional transfer flow at times in excess of the 3,000 MW north-to-south contractual limit.
- Unrecallable transmission outages.
- Congestion and operational challenges in neighboring systems.

Mitigation methods utilized to manage system congestion included, but are not limited to:

- Market redispatch.
- Out-of-merit-energy (OOME).
- Transmission Loading Relief (TLR).
- Post-contingent load shed plans.

Table 16 shows some mitigating actions that occurred Feb. 15-19. Market breached/bound transmission constraints indicate those for which SPP was actively trying to redispatch generation as a mitigation method. Only SPP member-owned constraints are included and, as these are daily counts, one constraint may recur multiple days. OOME counts include each unique resource instruction (e.g., an OOME cap issued for a resource at 100 MW and later reduced to 50 MW will be reflected as two OOMEs). TLRs are those issued by SPP. For reference, the 2016-2020 daily average number of OOMEs issued on any day in February is less than one,

[23] Transmission system constraints are transmission elements or groups of elements that limit or constrain distribution of electricity due to necessary imposition of reliable operating limits. Constraints are sometimes referred to by the industry as "flowgates."

and the daily average number of breached/bound constraints for the same time periods is 15.3 constraints.

Table 16: Daily mitigation summary (Feb. 15-19)

DAILY COUNT ITEM	FEB. 15	FEB. 16	FEB. 17	FEB. 18	FEB. 19
Market Breached/Bound Constraints	43	54	22	19	24
OOME	25	41	4	9	10
TLR	2	1	0	0	0

Figure 30 shows the number of SPP member-owned constraints that were overloaded during each hour Feb. 15-16. The sharp drop in the number of overloaded constraints that occurs after 7 a.m. Feb. 16 is due in part to SPP system load shed. Certain constraints may fall into multiple overload categories for a particular hour. The chart captures all instances of constraint loading in each category and does not necessarily indicate that loading persisted at high levels for the entire hour. For example, a constraint that was loaded at 105% for 20 minutes and loaded at 115% for 10 minutes would be captured in both the >100% and the >110% categories for a given hour.

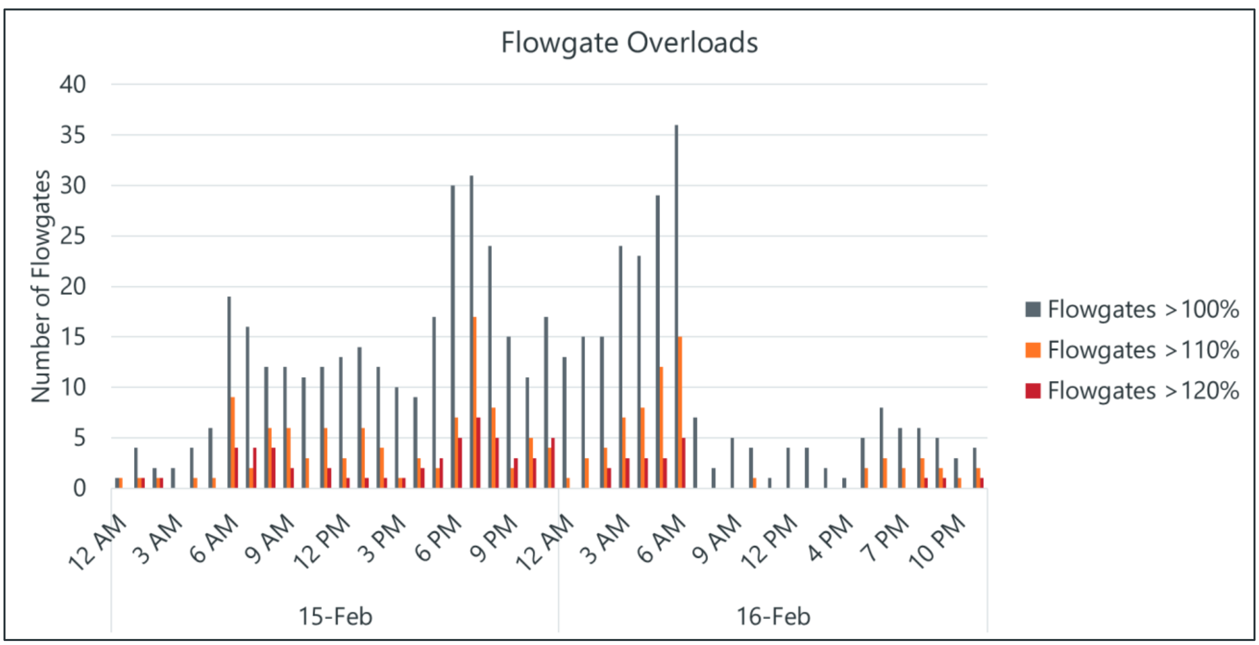

Figure 30: Hourly constraint overloads (Feb. 15-16)

Constraints loaded at or above 115% post-contingent are considered 'severely loaded.' These constraints are analyzed further by real-time staff to determine if they pose a potential risk to

the interconnection. Analysis includes running contingency analysis studies with both the monitored and contingent facilities removed from service to look for cascade type situations. During Feb. 15-19, real-time contingency analysis (RTCA) identified several constraints loaded over 115% post-contingent. The specific regions captured Figure 31 were particularly subject to severe loading.

Region	Flow Direction	Contributing Factors	Primary Reliability Concerns	Mitigation Actions
Western Kansas	NW → SE (into SPP)	• Heavy imports into SPP • 345 kV line outage	• Real-time overloads • Potential loss of load pocket • Low voltage	• OOME • Post-continent load shed plan
Eastern Nebraska Eastern Kansas	NE → SW (into SPP)	Heavy imports into SPP	Potential for widespread issues for the loss of 345 kV path	• TLR • OOME
Western Kansas	E → W (into SPP)	• Heavy imports into SPP • 500/161 kV transformer outage	• Potential voltage collapse in northern Arkansas • Real-time overload on 500 kV line	• TLR • OOME
Eastern Texas	E → W (into SPP and ERCOT)	• Heavy imports into SPP • Area generation trip	• High post-contingent loading in SPP • MISO concerns due to real-time overloads • Low voltage	TLR

Figure 31: Regional overview of severe loading

INTERCHANGE WITH NEIGHBORING ENTITIES

During the event, SPP observed the highest level of imports into its market since it went live in March 2014. SPP reached total imports of higher than 7,500 MW during the event and reached a total net scheduled interchange of more than 6,000 MW of imports. These imports were needed to help SPP meet demand and reserve obligations throughout much of the event. Figure 32 shows exports and imports by firm and nonfirm status for Feb. 10-20.

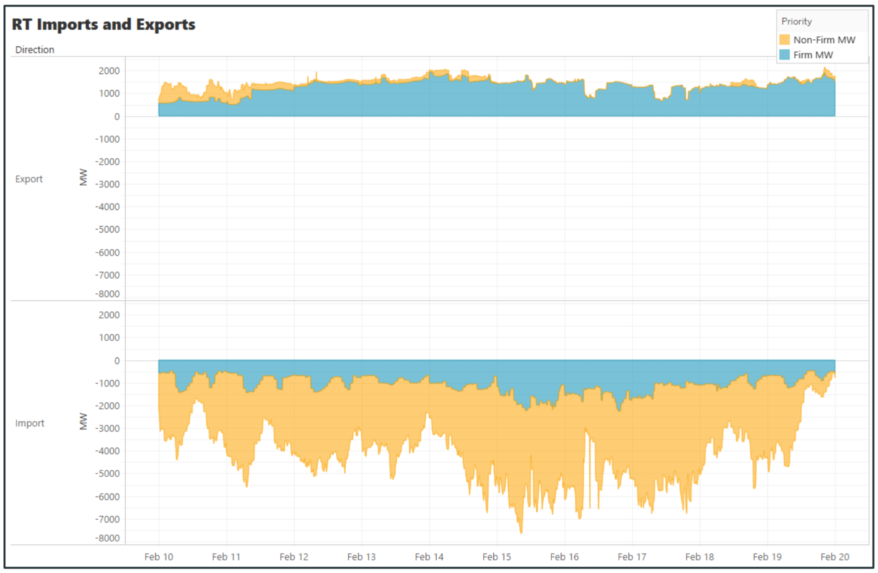

Figure 32: Real-time imports and exports by status (Feb. 10-20)

Curtailment of imports was a key factor in the necessity to shed load on both Feb. 15 and 16. Figure 33 provides a closer look at real-time imports and exports during critical time periods.

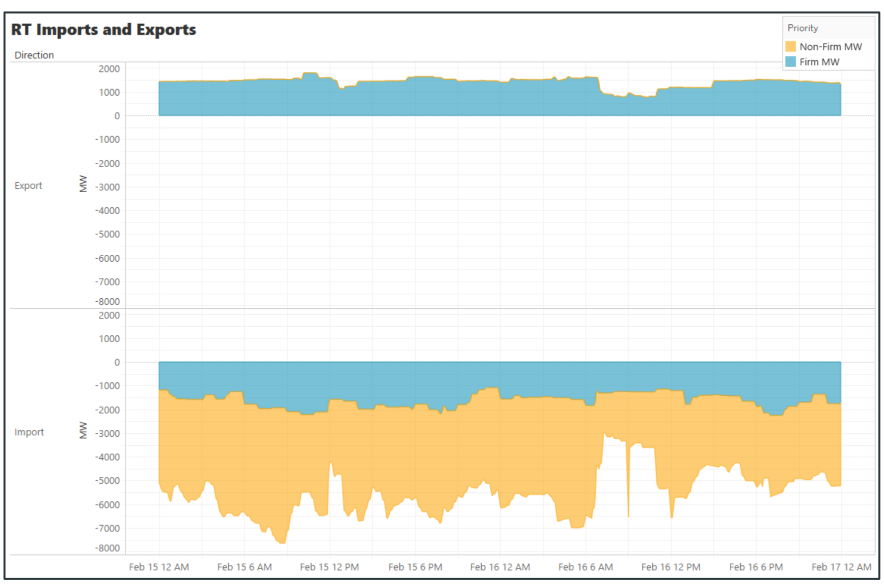

Figure 33: Real-time imports and exports by priority (Feb. 15-17)

The following figures illustrate SPP's net interchange with the remainder of the eastern interconnection during load-shed timeframes. On Feb. 15 (Figure 34), TLR curtailments effective at 12 p.m. reduced energy imports into SPP. Once energy imports were restored, SPP could instruct load restoration.

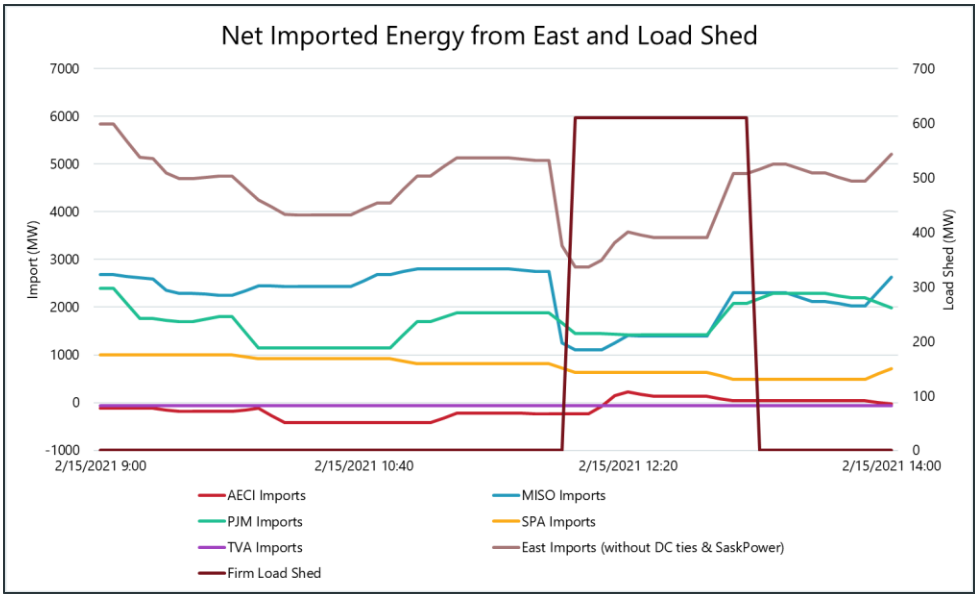

Figure 34: Eastern Interchange (Feb. 15, 2021)

As illustrated in Figure 35, on Feb. 16, schedule curtailments effective at 7 a.m. reduced energy imports into SPP. The sudden spike in imports that appeared shortly after 8:30 a.m. was the result of an inadvertent schedule adjustment during execution of the curtailments that was quickly corrected.

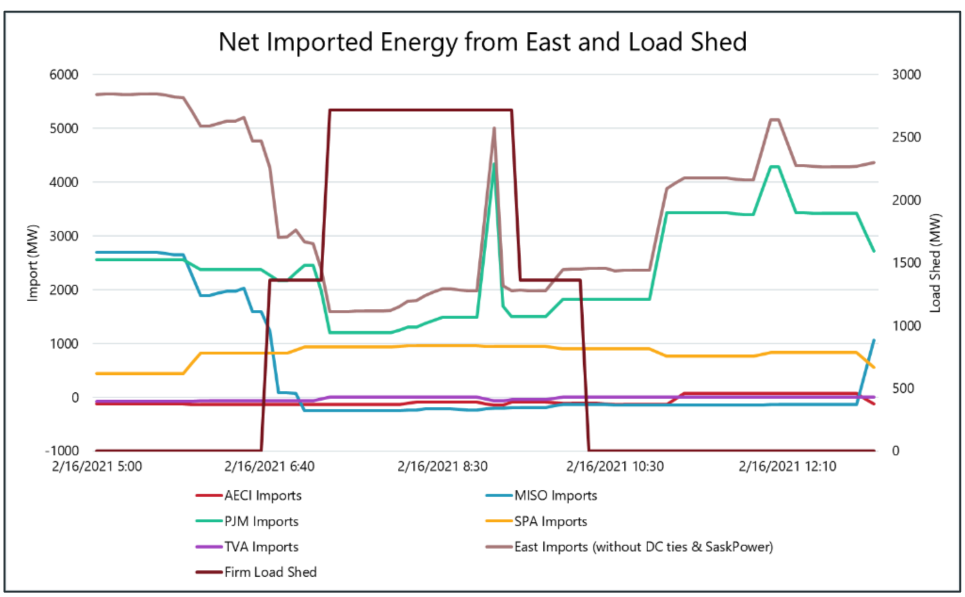

Figure 35: Eastern Interchange (Feb. 16, 2021)

WESTERN INTERCONNECT TIES

Seven DC ties connect SPP to the Western Interconnection. During the winter event, four of the seven ties were in service. The three ties that were not operable were out of service in advance of the winter event on scheduled outages. Figure 36 shows flows across the operable DC ties during Feb. 15-16. Negative values indicate flows into SPP.

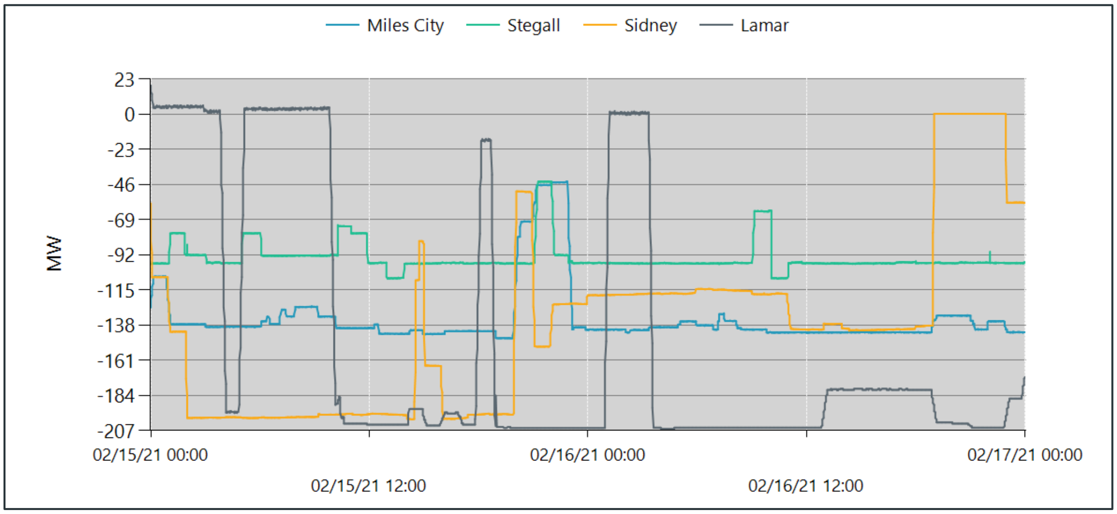

Figure 36: West DC Tie Summary

ERCOT TIES

Two DC ties connect SPP and ERCOT. Both were in operation during the winter event. Figure 37 shows flows across the ERCOT DC ties Feb. 15-16. Positive values indicate flows into ERCOT. At times, ERCOT DC ties were reduced due to curtailments associated with EEA 3 conditions in SPP and TLR curtailments from IDC due to congested constraints.

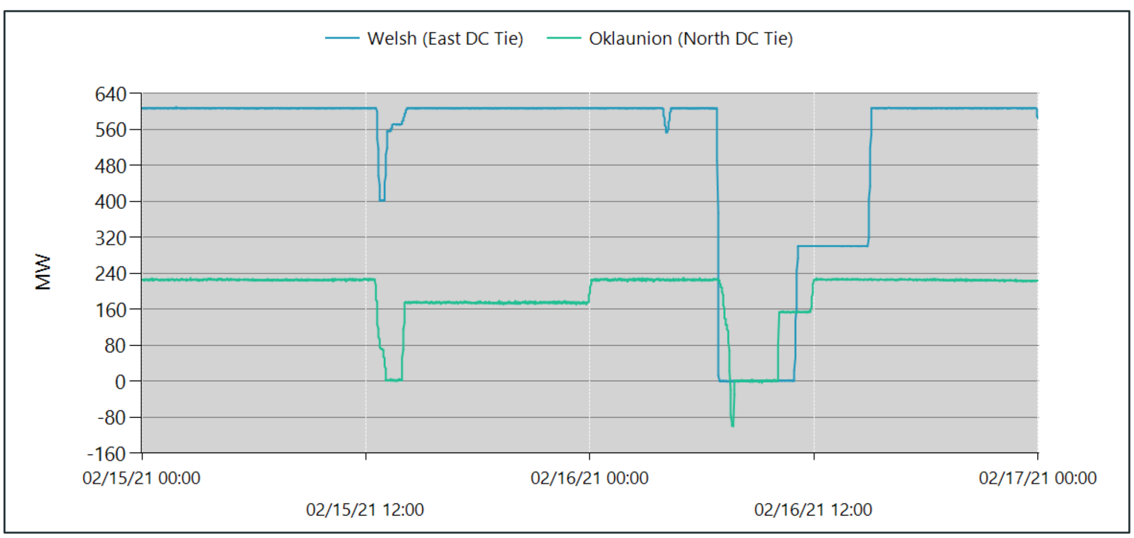

Figure 37: ERCOT DC Tie Summary

SASKPOWER PHASE SHIFTER

SaskPower (Saskatchewan, Canada) connects to SPP through a phase-shifting transformer. This tie was used to import power into SPP during the winter event. Figure 38 shows flows across the SaskPower phase shifter Feb. 15-16. Negative values indicate flows into SPP.

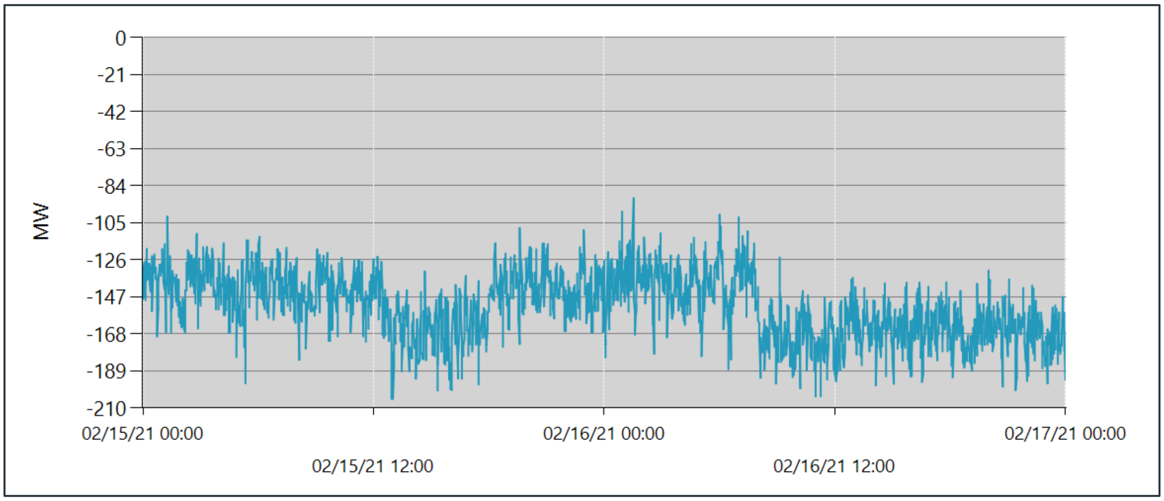

Figure 38: SaskPower Phase Shifter Flow

CONCLUSIONS REGARDING TRANSMISSION UTILIZATION AND PLANNING

Adequate transmission to deliver power is critically important in decreasing the impact of future extreme conditions, provides added resilience and could mitigate the need to implement load-shed procedures.

Although severe congestion was experienced at times during the 2021 winter weather event, significant investments that have been made over the last 10-15 years to upgrade the SPP transmission system allowed SPP to more fully utilize the generating resources that were available. SPP also was able to rely on capability of the broader transmission network to import significant amounts of energy from its neighbors. Transmission, both within and outside SPP, proved critical and beneficial in avoiding longer controlled interruptions of service.

Future evaluations of transmission needs should consider impacts of severe events.

This increased transmission utilization during the event pointed to the importance of appropriately assessing the deliverability of a dispersed set of resources across the Eastern Interconnection during such times. The event and congestion that existed also highlighted that SPP should improve efforts in the transmission planning study processes to evaluate adequate transmission capacity needed during normal and emergency conditions. Other forms of energy and an increased focus on improving the transmission system are critical to decrease the

possibility of further controlled interruption of service to customers. The 2021 winter weather event is a credible scenario that needs to be adequately scrutinized to understand potential impact of such events and protect against as SPP plans for the future (gas unavailability and the inability to meet demand with intermittent resources).

TRANSMISSION PLANNING RECOMMENDATIONS

Table 17: Summary of recommendations to the board related to transmission planning

#	TIER	CATEGORY	RECOMMENDATION
TXP 1	2	Policy	Develop policies that facilitate transmission expansion needed to improve SPP's ability to more effectively utilize the transmission system during severe events.
TXP 2	3	Policy	Develop transmission planning policies that improve input data, assumptions, or analysis techniques needed to better account for severe events.

SEAMS AGREEMENTS AND EMERGENCY ASSISTANCE

The SPP market relies on price signals to incent market participants to submit import interchange transactions when energy supply becomes limited. However, there may be situations where these commercial import interchange transactions are insufficient for the SPP BA to maintain adequate operating reserves and SPP must initiate an EEA in accordance with NERC Reliability Standards. Assistance from neighboring BAs and RTOs may need to be relied upon to provide emergency energy during these situations.

SPP had seams agreements with each of its neighbors during the winter weather event, but those agreements had inconsistent provisions regarding the exchange of and compensation for emergency energy. SPP relied heavily on imported energy provided by neighboring entities during the event, including from those with whom SPP has a seams agreement.

Certain agreements require that the requesting entity be in an EEA Level 2 or higher, that the emergency energy be formally requested, and that the amount (MWs) and duration be coordinated. As specified in these agreements, emergency energy transactions are intended to continue only until they can be replaced by normal commercial transactions. The rates and charges associated with these emergency energy transactions include a transmission charge and an energy portion.

Other agreements contain provisions specifying expectations for sharing emergency energy but do not specify payment terms. When emergency energy is provided pursuant to those

agreements, the provider is subject to prevailing market prices. The lack of specific payment terms in these agreements denies those providers certainty that they may recover costs associated with providing emergency energy. Lack of certainty could dis-incent the provision of available emergency assistance in the future.

CONCLUSIONS REGARDING SEAMS AGREEMENTS

During the 2021 winter weather event, SPP relied heavily on emergency assistance it received, but the inconsistent terms and provisions in current seams agreements create uncertainty going forward and should be addressed.

SEAMS AGREEMENTS RECOMMENDATIONS

Table 18: Summary of recommendations to the board related to seams agreements

#	TIER	CATEGORY	RECOMMENDATION
SEAMS 1	2	Action	Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance and fairly compensate emergency energy.

ANALYSIS OF FINANCE, SETTLEMENTS AND CREDIT

Extreme cold, increased electricity use, high price of natural gas and limited generation resulted in dramatic price increases across SPP's Integrated Marketplace footprint. SPP experienced historically high market settlements for the impacted operating days: $16.3 billion have been settled for Feb. 13-19. Figure 39 shows the sum of payments made to (MP Credits) and collected from (MP Charges) market participants (MP) from August 2020 to June 2021. The dramatic spikes in the invoice totals are due to the high prices during the event's operating dates.

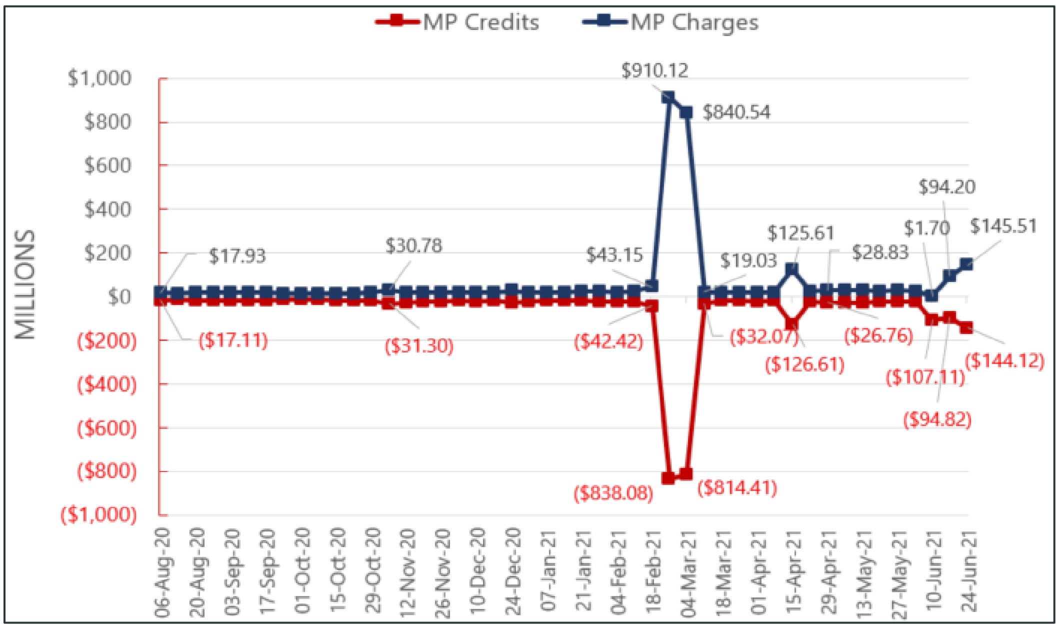

Figure 39: Weekly Marketplace Invoice Amounts (August 2020-June 2021)

Note: The June 10 invoice included the yearly ARR/TCR closeout dollars paid out on the last day of the planning year (May 31).

COST OF ENERGY

74% of settlement dollars ($12.13 billion) were due to various energy product charge types. Energy settlement dollars are paid to resources for injecting energy into the market and collected from load for consuming it. Prices were much higher than the typical averages for February. Due to the emergency status of the RTO and the need to find as much generation as possible, the DAMKT was committing all available units. In some cases, uneconomical units were committed, which resulted in high prices and led to a larger than normal volume of commitments in the DAMKT compared to the real-time balancing market (RTBM).

ORDER 831 – OFFER CAPS

SPP implemented tariff and system changes to comply with FERC Order 831. The order requires that each resource's incremental energy offer be capped at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer, as well as capped verified cost-based incremental energy offers at $2,000/MWh. Energy offers over $1,000 must be approved by the Market Monitoring Unit (MMU) before the start of the market (DA, RUC and RTBM).

SPP and the MMU filed a joint waiver with FERC to adjust the timelines for submission and verification of final costs and to align timing of deadlines with the anticipated timing of when generators would receive their final gas invoices.

MAKE-WHOLE PAYMENTS (MWP)

14% of total settlement dollars during the event were the result of make whole payments (MWP) to generators to make them whole to their costs (offers) in the market. A total of almost $880 million was paid out to resources that supplied energy in the DAMKT during the impacted days. That amount was funded by MPs with energy withdrawals in the DAMKT. An additional $220 million in MWP was paid in the RTBM to make generators whole to their real-time energy provided. RT MWP are funded by cost causers: virtual offers, deviations between day-ahead and real-time market for loads and imports/exports, and generators that deviate in real time.

SETTLEMENTS

Settlement calculations are performed for each operating day using the data available at that time. In addition to the three 'standard'[24] settlement postings, resettlements can be scheduled *as needed* following the S120 settlement posting for a given operating day. An MP may dispute items included in a settlement statement (or invoice) according to the following criteria established in the tariff/protocols.

There was a significant increase in settlement disputes as a result of the event. Many of the disputes were expected to be resolved with the posting of the S120 settlements. Some have already been granted upon verification that the issues were resolved.

MARKET PARTICIPANT CREDIT

The event created credit requirements never before seen for many of SPP's MPs. Market participants who were net purchasers of energy during the event experienced significant post-event collateral liabilities. The severity of energy prices could have potentially created a liquidity

[24] Standard settlement postings occur seven, 53 and 120 days after the operating day. These are referred to as the S7, S53, and S120 postings

crisis in the energy market and caused some participants to default on collateral calls or payment obligations. FERC approved a waiver extending the timing of collateral calls, which assisted load-serving utilities with capital management.

The event also exposed many MPs to payment of significantly higher natural gas invoices than normal and their accompanying collateral requirements from suppliers. Some participants were simultaneously exposed to neighboring energy markets that also experienced sustained and severe price spikes.

SPP's credit policy (Attachment X of the tariff) reacted aggressively to sudden and extreme energy price increases. By design, it assumes that swings in trading volumes and/or energy prices indicate sustained trends. Market participants with extremely high energy invoices were also required to post collateral to ensure future payments could be made. Many collateral requirements significantly outran the unsecured credit allowances granted by SPP.

During the event, the MMU calculated that virtual energy participants made $400 million in the market. The MMU expressed that had prices "gone the other way," SPP's market may have been exposed to credit/payment defaults from some of these financial-only participants.

Total potential exposure (TPE) calculations for day-ahead and real-time energy were ineffective in dealing with the short-term, temporary price spikes. The TPE would have required temporary collateral postings up to five times higher than actual invoice liabilities, inconsistent with the specific event risk. FERC's waiver effectively helped maintain liquidity, assuming all load-serving entities paid their invoices in full and on time.

Virtual reference prices may have undervalued credit risk during scenarios where actual DA/RT variances were greater than the reference prices used for credit exposure calculations. The extreme pricing experienced during the 2021 winter weather event may also have an adverse impact on the calculations of virtual reference prices for first quarter 2022.

DATA ISSUES

A number of factors had an impact on the data provided to settlements. There have been no identified issues with the settlement calculations, only the upstream data provided to the settlement system for use in the calculations:

- **Multiday reliability commitments:** A software error incorrectly locked in resources from Feb. 13 through Feb. 14. Software changes allowed offers to be updated starting Feb. 15, but analysis found this change did not completely fix the issue.
- **Day-ahead reprice:** Original DAMKT results for operating days Feb. 13 and 14 were not accurate as a result of commitments and prices based on MDRA offers, rather than updated offers. This caused prices to be much lower than if correct offers were used and impacted the day-ahead quantities awarded.

- **Order 831 offer caps:** As a result of MMU-verified offers pushed for Feb. 13 and 14 (due to the MDRA software error), some previously settled MWP were clawed back in the S120. For Feb. 15-19, the majority of offers were not approved before the market closed, and S120 MWP increased as offers were verified and approved by MMU.
- **Other data issues:** SPP was in a dispatch target adjustment (DTA) anytime an EEA 2 or above was declared. Unlike previous usage of DTA, the market continued to solve in these instances. Some resources were moved counter to the offer provided to the market. The decision was made to settle DTA time periods as out of merit energy.

EMERGENCY SCHEDULES

Four neighboring entities submitted emergency schedules to provide assistance to SPP during the event. The majority were settled via the normal settlement process, with some limited manual adjustments via processes outlined in SPP's seams agreements.

SPP ACCOUNTING

SPP utilizes automated clearing house (ACH), a form of electronic funds transfer that settles usually the day after a transaction is initiated to pay MPs on a weekly basis. SPP also uses ACH to debit the accounts of those MPs owing SPP for their market invoices and who have elected to have such amounts drawn from their accounts by SPP. Due to the next-day-settlement nature of ACH payments, banks impose limits on their customers for ACH transactions to mitigate their credit risk. The event resulted in the total amount of weekly market ACH payouts and ACH receipts being exponentially larger than SPP's ACH limits with its bank for a two-week period in March.

SPP'S PERFORMANCE OF FINANCIAL FUNCTIONS

The new settlements system enabled SPP to be efficient, flexible, collaborative and proactive during the settlement of the winter event operating days. The efficiency of the new system, including the ability to process and validate manual data files to address data issues in real time, provided a means to deliver financial data to other departments and to the officer team quickly for consideration in the decision-making process.

SPP's credit department was able to use this data to research and analyze various scenarios that might have resulted in potential credit default events. As a result, staff filed a waiver request approved by FERC to extend the collateral call timeframe to help ensure liquidity in the energy market during the event. Staff was able to coordinate with all of the significantly affected utilities to provide data for their capital management and to ensure payments were made in full and on time.

As soon as SPP's ACH issue became known, staff reached out to and regularly updated its bank to explain the event and to alert them about the issue with the upcoming large ACH

transactions. SPP and the bank were able to temporarily switch to an ACH process called ACH secured funds, resolving limit issues and ensuring MPs received their payments on the regular payment due date. All transactions cleared on time with no problems and with no adverse or unexpected impacts on MPs.

CONCLUSIONS REGARDING CREDIT AND SETTLEMENTS

MDRA commitments resulted in data scenarios that are not typically seen in the market. In many cases, the tariff does not provide clear language with regard to how SPP systems should treat these scenarios. There should also be consideration given to where the tariff is lacking and what additional language is needed to avoid similar data issues should there be another weather event that impacts the SPP footprint.

Some scenarios encountered during the event weren't addressed in the original 831 compliance filing. SPP and the MMU will collaborate to understand these impacts and potential need for future changes to the tariff language, market processes and settlement calculations.

SPP should consider changes to the language filed with FERC regarding cost submissions and verification timelines. The timeline outlined in the tariff is not feasible in instances like those experienced during the event. SPP may also consider working with FERC to establish possible changes to capping levels based on the emergency status of the RTO.

The current design of the market allows for participation of non-asset owning MPs or financial-only participants. In some cases, these financial-only MPs benefited greatly from these events. Further analysis should be conducted to determine if these payments are appropriate and if the current design of the market is sufficient.

CREDIT AND SETTLEMENT RECOMMENDATIONS

Table 19: Summary of recommendations to the board related to credit

#	TIER	CATEGORY	RECOMMENDATION
CR 1	2	Assessment	Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in 1Q'22.
CR 2	3	Assessment	Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes.
CR 3	3	Action	Clarify tariff language related to SPP's settlements and credit-related authorities and responsibilities.

ANALYSIS OF COMMUNICATIONS

Throughout the February 2021 winter weather event, SPP used a number of communication channels to keep members and public throughout its service territory apprised of changing grid conditions. Operators followed clearly defined protocols for coordinating with member utilities.

In its analysis of communications before, during and immediately after the event, the Communications Comprehensive Review (CCR) team sought to identify ways to improve the accuracy, timeliness, reach and overall effectiveness of future emergency communications. To do so, they conducted several analyses and gathered input from several specific stakeholder audiences.

First, the CCR team evaluated the timeline and content of written communications during the week of Feb. 14-20. This review helped the team identify where messaging could have been clearer, where the sequence of communications activities was either helpful or problematic, why some messages were timelier than others and whether the appropriate audiences received the right information at the right time.

Second, the team conducted surveys of specific stakeholder groups to gauge their assessment of SPP's storm-related communications. The team surveyed:

- Members of the Regional State Committee (RSC) and Cost Allocation Working Group (CAWG), and representatives of SPP's member and market participant companies, to gauge the overall effectiveness of SPP's emergency communications.
- SPP's officers and directors to assess the time they spent communicating with individual stakeholders during the winter storm and to identify opportunities to make more effective use of leadership resources during emergency events.

Third, SPP staff and stakeholders conducted interviews with television, radio and newspaper journalists who reported on SPP's activities during the winter storm. The team sought to learn whether SPP's public relations activities during the winter storm were effective and appropriate.

Fourth, SPP facilitated discussions with stakeholders to learn more about the impacts of SPP's communications activities. Over a series of virtual meetings, the CCR explored stakeholders' experiences and emergency response activities, sought context for SPP's event data, and identified lessons learned and best practices that could be applied in future emergencies.

Lastly, the CCR team reviewed the effectiveness of SPP's public communications tools: SPP's website, social media channels, press releases and email distribution lists. Staff reviewed and shared SPP's website analytics, including up and downtime, traffic and frequently visited pages; social media analytics regarding the reach and engagement of storm-related posts; and reports of newspaper, web, television and radio coverage of SPP's storm response.

Overall, SPP's stakeholders were satisfied with and felt appropriately informed by SPP's emergency communications efforts. SPP's surveys of stakeholders showed strong ratings of the effectiveness of SPP's communications, a majority of respondents agreed that SPP's communications increased their trust in the organization's credibility.

There were, however, opportunities to improve communication practices for future emergency events. Before the cold weather event, SPP's communication and updates to members was beneficial and helped prepare the members for the event. Once the event began, the need for frequent communication increased, as did the size and complexity of SPP's audience.

SPP and its members and other stakeholders can improve communications by working together to improve communication with broad audiences and to clearly delineate communications roles during emergency events. A coordinated communication effort can reach all critical audiences with the information they need to take appropriate action and to reduce misunderstanding. A summary of the CCR's findings is included below, and more detail is available in their full report published on SPP.org.[25]

TIMELINE OF COMMUNICATIONS

Beginning Feb. 4, 2021, SPP issued several weather alerts, conservative operations declarations and emergency energy alerts. Figure 1, provided in the section labeled Events of Feb. 4-20 shows the times each of these alerts was declared.

Each of the following sections examines the timeline of SPP's communications with different audiences related to these operational events.

OPERATIONAL COMMUNICATION

Operational communication differs from other types of communication because it is almost exclusively between SPP operations and member company operations staff. This operator-to-operator communication happens daily under normal operations but was thrust into the public eye during the winter weather event.

SPP used R-Comm for the majority of its operational communications. Other communication channels used were email, phone calls and the Open Access Same Time Information System (OASIS) an internet-based information and scheduling system for electric power transmission services.

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[25] "A Comprehensive Review of SPP Communications during the Feb. 2021 Winter Storm: Analysis and Recommendations"

CONCLUSIONS REGARDING OPERATIONAL COMMUNICATION

When examining operator-to-operator communication, the team looked at many data points including survey results, analysis of the existing energy emergency alert (EEA) process and comments and feedback from operational staff.

SPP worked with members' corporate communications departments to issue public appeals on Sunday, Feb. 14 to reduce load on days following. The timing allowed customers to be aware and appeared to significantly reduce load compared to forecast during the highest load periods. The North American Electric Reliability Corporation (NERC) Attachment 1 of EOP-011-1 does not recommend public appeals to reduce load until a balancing authority reaches an EEA level 2. Issuing public appeals does require some time to make the appeal and for customers to respond. It seems more reasonable to have an appeal issued in advance of the event when possible.

SPP and nonoperational stakeholders should routinely drill load-shed and other procedures to prepare for future events. SPP should encourage consistent assessment, updates and testing of member emergency plans and communication with attention to critical infrastructure.

Stakeholders felt SPP should have provided earlier operator notifications to individuals in member organizations outside of operations staff. They should create an operational event early notification process, using R-Comm, OASIS or other operational system alerts, for key stakeholders. During long events, SPP operations should provide interim updates to member company operations staff.

Before the cold weather event, SPP's communication and updates to members were beneficial and helped prepare the members for the event. Once the event started, communication between SPP and the members reduced. Increased communication during these time would help the members' operations staff understand the current situations and what is needed.

If operational system alerts are utilized for nonoperations staff and the public, SPP should develop talking points, graphics and other materials that simplify and explain these alerts for broader audiences.

SPP should designate dedicated subject matter experts for communication during events.

STAKEHOLDER COMMUNICATION

SPP used various platforms to reach stakeholders, including alerts from its emergency communication tool, xMatters, emails to exploders and distribution lists, daily webinar briefings, social media and website updates.

Beginning Feb. 14, SPP issued press releases and alerts about the winter weather event and its impact on system conditions. These notices continued throughout the week to inform

stakeholders and customers of changing conditions, concluding with an alert issued Feb. 19 noting that SPP had ended its EEA1 state and returned to conservative operations.

Daily briefings were also held with stakeholders throughout the week of the event. These daily briefings helped communication efforts tremendously. The briefings helped members communicate with their end-users and equipped them with consistent language, resources and materials to explain the event to public audiences.

Additionally, SPP officers hosted calls with members, reached out to individuals and provided open and direct lines of communication.

SPP's communication efforts were greatly helped by the years of preparation staff had done before the event to build relationships with member communication staff. This included an annual testing of its emergency communication system, developing contact lists and hosting annual communication conferences.

CONCLUSIONS REGARDING STAKEHOLDER COMMUNICATION

While there were many things that SPP did well when communicating with stakeholders, the CCR identified areas for improvement.

More preparation is needed ahead of any future events. SPP should reassess who receives emergency alerts and tools for updating contacts. They should consider defining a "calling tree" procedure that clearly assigns responsibilities for communicating with specific audiences and implement a process to regularly update contact lists.

Many stakeholders felt communication should have been earlier and more varied. SPP should identify opportunities to send members notices about more alert levels and provide more detailed event information to points of contact identified at each organization. SPP should consider more effective and frequent communications on other aspects of the event, including market and repricing activities.

There are many efforts SPP and member companies can do together to improve communication to stakeholders, including coordination of press releases and media briefings. The planning of media briefings should be done with members and local utilities with enough time for them to coordinate their own local press briefings as a follow-up. They should also work to develop educational materials that explain SPP's and members' load-shed procedures or responsibilities.

GOVERNMENT AFFAIRS AND REGULATORY COMMUNICATION

As conditions started to deteriorate, SPP staff alerted member company government affairs representatives, the SPP Regional State Committee (RSC) and Federal Energy Regulatory

Commission (FERC) staff about worsening conditions in our footprint. This was done in a variety of ways through emails, phone calls and webinars. SPP also sent emails to U.S. congressional offices as well as governor offices and state energy offices across the SPP region, apprising of changing conditions throughout the week of the event.

CONCLUSIONS REGARDING GOVERNMENT AND REGULATORY COMMUNICATIONS

SPP identified opportunities for improvement when communicating with government affairs staff and regulatory officials.

Early in the storm, SPP included government relations staff on communications to member company communication staff. This helped to ensure messaging was getting to the right individuals. In the future, SPP should examine additional opportunities for collaborative communication between SPP's government affairs and regulatory teams and consider including member government affairs and regulatory staff earlier and on more notifications.

Contact list management impacted SPP's ability to reach government affairs and regulatory representatives. Some lists were outdated due to election-related turnover. SPP may more frequently update contact, improve contact-update processes for public officers, or consider tools to allow self-updates.

More frequent joint calls and webinars with the RSC, CAWG, member government affairs and regulatory staff and elected officials would ensure more consistent communication and address some concerns from stakeholders who felt communication to these groups was insufficient. SPP should have clear emergency points of contact for RSC and other public officials, and examine opportunities for rapid notification of certain alerts from operations to commissioners.

SPP should develop educational materials and resources about SPP, RTO/TOPs and energy emergencies for government affairs and regulatory staff, state commissioners, congressional offices and governors' offices. Staff should look for opportunities to remind officials of the benefits of RTO services in event communications.

PUBLIC COMMUNICATION

During the winter weather event, SPP distributed nine press releases and provided 10 informational updates regarding grid conditions. These were sent to various groups including stakeholders, news release exploder subscribers, media outlets with whom SPP had developed relationships, member company communication staff and posted to www.spp.org. When possible, member company communication staff were given previews of releases to create consistent messaging.

SPP communication staff received an influx of media inquiries at the onset of the event. In addition to our regular media contacts, we received inquiries from a large number of small, local news outlets across the footprint. The most inquiries came from Oklahoma, but all SPP states were represented. We also received inquiries from media outside the footprint.

It quickly became apparent the request load was too large to respond to all inquiries individually. At that point, SPP decided to host daily press briefings. SPP held three daily "State of the Grid" briefings for news media and stakeholders with 924 attendees across three days. These livestreams were broadcast by some affiliate networks, and recordings of each briefing were posted on social media.

SPP saw increased traffic on its website. After the first EEA3 was declared Feb. 15, SPP experienced rapid increases in website traffic, slowing or interrupting site access for some users. These spikes in traffic often followed social media posts, especially about EEAs or impending outages. Due to the increased traffic, SPP created a grid conditions page where current alerts, definitions of alert levels and a timeline with each new event were posted.

Throughout the storm, SPP posted updates to Twitter, Facebook, LinkedIn and Instagram. The first post to social media about the storm was the Feb. 14 press release. Between Feb. 14 and Feb. 20, 42 Twitter tweets, 24 Facebook posts, 23 LinkedIn posts and 18 Instagram posts were made.

On Twitter, SPP gained 5,479 followers and had 3.5 million engagements with posts. On Facebook, SPP gained over 12,000 page likes and had over 160,000 engagements.

Facebook engagement escalated quickly, peaking Feb. 15 and began to decline Feb. 16. Twitter impressions peaked quickly and declined more slowly. LinkedIn and Instagram had far fewer engagements than Facebook or Twitter.

SPP communications posted five videos during the winter weather event, including the three recordings of the "State of the Grid" news briefings and two "explainer" videos. The explainer videos were titled "Who is Southwest Power Pool?" and "Why was power interrupted during this storm?" and featured SPP officers. These video postings resulted in 8,800 views, totaling over 1,000 hours, and 139 new YouTube subscribers.

CONCLUSIONS REGARDING PUBLIC COMMUNICATIONS

SPP gained invaluable insight from managing social media during the winter weather event that will help navigate social media platforms in the future, both during normal operating circumstances and emergencies.

During a multiday event, day one is the most critical time to engage social users. Spikes in engagement are short-lived, and SPP should use these temporary increases in engagement to their advantage to reach as many people as possible. SPP should focus on using the most effective platforms, and SPP received the most engagement on Twitter and Facebook. In the

future, SPP should utilize Twitter and Facebook for real-time notifications since they provide the most engagement. Graphics that explain the status of the grid and what to do will get high engagement. To combat negative sentiment scores, SPP can change messaging to better empathize with end-user challenges and combat misinformation by collaborating with news outlets and members.

Because there was limited engagement on LinkedIn and Instagram, it may not be worth the time to monitor and create real-time content for these platforms during emergencies. These platforms may be better utilized for post-event information or pre-event educational materials. Since Facebook proved to be the greatest driver of traffic to videos, SPP should prioritize video sharing on that platform primarily.

SPP received positive feedback on both the daily briefing and explainer videos. While the explainer videos received more views than videos posted under typical circumstances, the recordings of the daily "State of the Grid" briefings were the most watched. Audiences wanted to know who SPP is, but they wanted to know what was happening more. In light of this information, SPP should consider promoting daily briefing information on social media platforms before they begin. SPP can better utilize video in emergencies by preparing videos in advance for a public audience that are tailored to emergency events.

SPP staff interviewed four reporters from a local newspaper, local public radio, industry publication and a local TV station anchor to gather feedback on its communication with media. This audience represented a variety of media outlets and covered the majority of the SPP footprint. Each of the reporters indicated they got their news from a mix of sources including SPP's social media, emails from SPP, its website and communication with member companies and would likely continue to use a variety of sources in the future. All reporters said they would benefit from educational and other related materials posted on the SPP website before the event or sent in conjunction with press releases.

In the wake of the storm, there may be demand for direct education from SPP to news media, and SPP should consider an annual media day in collaboration with members to educate the public on who SPP is, who are their members are, the benefits they provide and how they work together to protect the grid.

SPP received such a flood of media requests at the onset of the winter weather event that the "State of the Grid" press briefings became critical for responding to media and providing public updates. While feedback from media told SPP these briefings were helpful, SPP should consider a mix of morning and afternoon briefings to better meet the needs of the different types of reporters.

SPP's media briefings were often livestreamed by local news outlets. Knowing this, SPP should work to create messages tailored for the public, and ensure speakers receive proper media training. To reach a broader audience at briefings, SPP can improve promotion of briefings and its news distribution sign-up process.

The electric industry is complex, and information regarding the status of the grid can be difficult to communicate. This event highlighted the need to improve public emergency communication. Press releases should use clear, simple terms and be free of industry jargon. All communication should provide up-to-date information, local utilities impacted by the event, and simple actions to take.

SPP's website is a valuable source of information, but winter weather event was a unique test of its capabilities. It experienced rapid increases in website traffic, hindering the distribution of information. From this, SPP learned how large traffic spikes can be during emergency events and what should be done to mitigate against the risk of negative impacts to the site due to increased traffic. SPP should increase server capacity ahead of weather events and more clearly label banners on the site. Throttling and file reduction can help to reduce disruption further.

KEY FINDINGS RELATED TO COMMUNICATIONS

Overall, SPP's stakeholders were satisfied with and felt appropriately informed by SPP's emergency communications efforts. In a survey of 155 representatives of SPP's member and market participant organizations, 80% rated the overall effectiveness of SPP's communication during the winter storm either "effective" or "highly effective." In a survey of SPP's RSC and CAWG, 85% of respondents rated SPP "effective" or "highly effective." More than 70% of stakeholder respondents and 55% of RSC and CAWG respondents agreed or strongly agreed that SPP's communications increased their trust in the organization's credibility.

There were exceptions to stakeholders' satisfaction with SPP's emergency communications. Some individuals did not receive information in as timely a manner as they would have liked. In many cases, this occurred because SPP sent communications to particular points of contact at its stakeholder organizations and that information was not further disseminated within those organizations.

Some stakeholders were unsure what to do with the information they received during the event. While SPP and its member operators had already developed and practiced response procedures, some other stakeholders were unsure of their roles during the event. This event marked the first time some audiences in the SPP region had heard of or from SPP.

The electric utility industry is complex, and SPP's role is usually "behind-the-scenes." General audiences (including the public, media and elected officials) lack an understanding of the variables that affect the reliable delivery of electricity on a regional scale. SPP tends to communicate using technical language that may be useful for industry professionals but contains too much jargon for general audiences.

The winter weather event exposed a need for better coordination between SPP, members and distributors to communicate about load shed. As the event worsened and threat of outages became real, audiences who were previously unaware of SPP's role became interested in the RTO's load-shed procedures. They wanted to know what factored into SPP's decisions

regarding Energy Emergency Alerts, calls for conservation and load curtailment. A spike in interest and a need to communicate complex concepts to new audiences proved a challenge.

Post-event analysis confirmed that SPP's transmission-operating and load-serving member utilities all received and responded to load-shed communications in a timely manner. Utilities quickly brought the system into balance and SPP restored load quickly and effectively.

Long after the outages, SPP and its members continued to field questions from distribution companies, regulators, reporters and the public about SPP's authority to curtail load, SPP's and its members' roles in choosing what load to curtail and why curtailing load was necessary.

COMMUNICATIONS RECOMMENDATIONS

Table 20: Summary of recommendations to the board related to communications

#	TIER	CATEGORY	RECOMMENDATION
COMM 1	2	Action	Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: • Processes that ensure stakeholders have a dependable way to receive timely, accurate and relevant information regarding emergencies. • Plans to drill emergency communications procedures with all relevant stakeholders. • Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers, and government entities and stay up-to-date.
COMM 2	2	Assessment	Evaluate and propose needed enhancements to communications tools and channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc.
COMM 3	3	Action	Form a stakeholder group whose scope would include discussion of matters related to emergency communications.
COMM 4	3	Action	To increase public awareness of and satisfaction with SPP, develop materials intended to educate general audiences on foundational electric utility industry concepts and SPP's role in ensuring electric reliability.

CONCLUSION

The February 2021 winter weather event was historic in nearly every respect, from the widespread and severe nature of the storm itself to the response it required from SPP and its stakeholders to preserve the reliability of the regional grid. SPP credits its success in responding to the winter storm to its many partners, including its member utilities, neighboring systems and millions of people who voluntarily made sacrifices to conserve energy in the interest of the greater good. Likewise, SPP owes its stakeholders thanks for their thoughtful and deliberate contributions to this report.

In a statement to SPP's staff on Feb. 18, in the immediate aftermath of the storm, SPP's president and CEO wrote the following regarding the organization's obligation to learn from the experience:

> *"We will do our best and we will come out on the other side wiser and more prepared for the future. Will we learn from the events of this week? Definitely. Will we identify improvements? Most certainly. Will our best be even better next time? Absolutely."*

Many of the factors that contributed to the severity of the February storm's impacts were externalities that SPP could not control: low temperatures, the duration of the storm and fuel prices set by gas providers, for instance. Similarly, SPP and its stakeholders will almost inevitably face other crises that arise from circumstances they cannot prevent, whether they result from natural disasters, mechanical failures or acts of terrorism. This comprehensive review, though, demonstrates the SPP organization's commitment to doing everything in its power to safeguard the reliability and affordability of electricity delivery in its region.

As this report's name suggests, SPP's analysis of its response to the February storm was comprehensive. The results are indicative of dozens of meetings in which hundreds of stakeholders spent thousands of hours considering how to achieve SPP's mission — responsibly and economically keeping the lights on today and in the future — even when facing the toughest challenges imaginable. This report does not mark the end of SPP's learning process, though. From here, with direction from SPP's independent board, SPP will set about the ongoing process of continuing to engage stakeholders in making the recommended improvements. Where assessments need to be made, plans carried out or policies written or amended, SPP staff will partner closely with stakeholders, because SPP's success, in the past, present and future, depends largely on the strength of its stakeholder engagement.

APPENDICES

APPENDIX A: SPP'S ROLES IN ASSURING ELECTRIC RELIABILITY

SPP serves in a number of capacities related to the coordination of the regional power grid. Those most relevant to the February 2021 winter weather event are its roles as a regional transmission organization (RTO), reliability coordinator, balancing authority and market administrator.

SPP AS AN RTO

As an RTO, SPP is granted specific responsibilities by the Federal Energy Regulatory Commission (FERC). Rates, terms and conditions by which SPP oversees the regional power grid and coordinates with its member utilities are defined in a FERC-approved tariff. 106 member utilities in 14 states are members of the SPP RTO, meaning they have placed their power plants and extra high-voltage transmission facilities under SPP's functional control. RTO membership is voluntary, though the member roster has steadily grown since SPP became an RTO in 2004 because of the value the organization provides: enhanced reliability and cost savings as compared to the status quo of utilities operating on their own.

SPP AS A RELIABILITY COORDINATOR

As a reliability coordinator (RC), SPP functions like an air traffic controller for electricity. Air traffic controllers don't own skies, planes or airports they coordinate. Similarly, SPP doesn't own power plants, transmission lines or electricity, but it directs these and other components of the bulk power system to ensure electricity is delivered safely and affordably from where it's generated to where it's used in real time. RC activities are governed by the North American Electric Reliability Corporation (NERC), who enforces standards related to the reliable operation of the country's bulk electric system. (For more information on the standards most relevant to the winter event, see the Applicable Standards and Regulations section.)

SPP staffs a 24/7 control room and backup facility from which it maintains constant communication with member utilities. RC staff constantly plan for contingencies and operate from an N-minus-one posture, meaning they work to keep the grid ready to respond to the next worst contingency such as the loss of our largest generating unit. SPP keeps operating reserves online equivalent to one-and-a-half times its region's largest generating unit. This means it keeps enough generation online to meet real-time demand and enough "spinning" and ready to flow onto the grid immediately if committed generation becomes unavailable.

SPP AS A BALANCING AUTHORITY

The nation's power grid comprises three interconnections: Eastern, Western and ERCOT (Texas). Each is a single massive, highly interconnected network of generators, transmission lines and substations that feed power to local distribution networks that serve homes and businesses. Disturbances anywhere on one of these networks are felt across the entire interconnection. The SPP RTO is part of the Eastern Interconnection.

As a balancing authority (BA), SPP keeps real-time production and consumption of electricity in balance. It does this for its entire 14-state balancing authority area. Other entities serve as the BAs in other regions, big and small, across the country. Production and consumption of electricity must be kept nearly perfectly in balance to prevent equipment failures and the potential for large-scale, cascading outages. In the absence of utility-scale energy storage devices like batteries, electricity is produced, transported, delivered and consumed nearly simultaneously. Damage to the grid can occur if either more or less energy is produced than is needed at that time. SPP forecasts demand (also called load) in five-minute increments, and sends signals to 800+ generators in its BA area to ensure they're collectively producing just enough power to meet demand without overloading lines or burning out equipment.

SPP AS A MARKET ADMINISTRATOR

SPP facilitates a wholesale electricity market that automates selection of the cheapest available energy to serve load minute-by-minute. SPP's market is fuel-agnostic, meaning it doesn't favor any particular fuel type over another but treats coal the same as wind, natural gas the same as nuclear power, etc. The market only takes into account the price at which generators offer energy into the market, and it picks the least-cost power available to meet demand, taking into account operating characteristics such as lead times (the amount of time it takes a generator to spin up from inactivity), minimum run-times, etc.

SPP's is a day-ahead market, meaning it commits generation a day in advance. As the region nears real-time, intraday market processes make additional commitments to ensure the right amount of generation is online as weather patterns, electricity use and other factors vary from forecasts.

Like its tariff, SPP's market design is approved by FERC, and its administration is overseen by an independent market monitor that watches to ensure the market operates fairly and without undue influence by any single participant or group of like-minded participants. SPP is a not-for-profit organization, registered as a 501(c)(6) in the state of Arkansas. As a market administrator, it facilitates the sale and purchase of power through its market, and SPP administers the process by which those transactions are invoiced and settled, but it does not profit off these activities. SPP is completely funded by an administrative fee charged to our members and market participants based on the use of our services.

In summary, SPP is authorized and regulated by FERC to carry out certain responsibilities related to the reliable operation of the regional power grid. It is required to comply with enforceable NERC standards, and its staff works around the clock every day to ensure energy production and consumption are held in balance while planning against contingencies that could threaten reliability. SPP's market helps do this by committing the least-cost generation that's available to serve load.

APPENDIX B: PREPARATION AND TRAINING

SPP holds its operators to exceptionally high training standards, ensuring every operator exceeds NERC's minimum training requirements and is equipped to respond to a wide array of operational issues. This includes specific training that addresses cold-weather events. SPP's operators work on six-week shifts, which include one week every rotational schedule dedicated to training.

NERC requires system operators to undergo 200 hours of training every three years to maintain their RC certification. SPP holds its operators to standards above those requirements, ensuring every one receives 85-100 hours of training every year. SPP also requires every operator to be certified both as an RC and on the specific functions they perform.

SPP requires its operators to receive training consistent with NERC Standard PER-005. Additionally, it requires operators to complete emergency operations training annually consistent with standards EOP-006 (System Restoration), EOP -011 (Emergency Operations), IRO-008 (Reliability Coordinator Operational Analyses and Real-time Assessments), IRO-009 (Reliability Coordinator Actions to Operate within IROLs) and PRC-001 (System Protection Coordination).

Operators typically earn 65-80 continuing education hours (CEH) annually from events developed and delivered by SPP's customer training staff. These training events — also attended by SPP members' operators — include Regional Emergency Operations (REOPS) classes, Power System Restoration drills, System Operations Conferences, and classes that focus on specific topics like conservative operations, event reporting, energy emergency alerts and unit commitment fundamentals. Many of these sessions include training specifically intended to prepare operators to respond to cold-weather events, and plans are already underway to update training content that incorporates circumstances and lessons learned from the February 2021 winter weather event.

Operators also receive training delivered by SPP's operations analysis and performance support (OAPS) team. This training, which does not count toward NERC CEH requirements, is based on real-world situations that might occur in SPP's control room and addresses topics like communications, the potential loss of a control center, remedial action schemes, capacity emergencies, severe loading transmission emergencies, load shed and energy emergency alerts. OAPS training typically provides every operator 30-35 hours of role-specific training each year.

SPP also performs R-Comm training to review how the SPP BA uses R-Comm to issue load-shed instructions and how entities are expected to respond to the communication.

LOAD-SHED TRAINING

SPP's operations staff performs load-shed tests every 11th Wednesday. SPP does not test individual TOP plans, but some TOPs inform SPP when they test their demand-side load-shed plans.

SPP operations engineering staff review documents that members submit related to NERC EOP standards, including load-shed plans. SPP reviews TOP or BA-submitted plans within 30 days of receipt to:

- Confirm that notification to the RC is included when experiencing an operating emergency.
- Mitigate operating emergencies regarding any reliability risks identified between operating plans.
- Confirm compatibility and interdependency with other BA and TOP operating plans.
- Confirm coordination to avoid risk to wide-area reliability.
- Review and confirm any communication information listed for SPP.
- Review each document for consistency with SPP criteria and procedures when interactions with SPP are required.
- Review each topic discussed for criteria and compare against SPP's operating criteria.

APPENDIX C: APPLICABLE STANDARDS

Below are the NERC standards most relevant to SPP's and its members' obligations during the winter weather event.

- Emergency Preparedness and Operations (EOP): EOP-011-1 - Emergency Operations.
- Transmission Operations (TOP):
  - TOP-001-4 – Transmission Operations.[26]
  - TOP-002-4 – Operations Planning.
- Resource and Demand Balancing (BAL): BAL-001-2 - Real Power Balancing Control Performance.
- Interconnection Reliability Operations and Coordination (IRO): IRO-001-4 - Reliability Coordination – Responsibilities.

[26] TOP-001-4 was in effect during the event but was retired and replaced with TOP-001-5 on April 1, 2021.

APPENDIX D: PRIOR RELIABILITY EVENTS

Before the February 2021 winter storm event, the SPP and neighboring regions experienced extreme winter weather conditions in 2011 and 2018 that resulted in two joint Federal Energy Regulatory Commission and North American Electric Reliability Corporation (FERC/NERC) reports. [27,28] The 2011 event report made 26 recommendations for the electric industry and six for the gas industry, including improved coordination between the electric and gas industries. Recommendations for the electric industry focused on five areas: planning and reserves, coordination with generator owners and operators, winterization, communication and load shedding. The 2018 event report contained 13 recommendations related to generator cold weather reliability, situational awareness, reliability coordinator communications, seasonal studies, system operating limits, reserves and load forecasting.

As part of SPP's comprehensive review following the February 2021 event, an assessment of the previous event recommendations was conducted. SPP's current operational and planning processes and tools incorporate a majority of the applicable recommendations from both events.

FEB. 1-5, 2011, SOUTHWEST COLD WEATHER EVENT

This event involved extremely low temperatures, wind, snow and ice. Electric entities located within three NERC regions, the Texas Reliability Entity, Inc. (TRE), the Western Electricity Coordinating Council (WECC), and SPP were affected by the extreme weather, as were gas entities in Texas, New Mexico and Arizona. While three balancing authorities (BA) in the SPP footprint issued varying levels of energy emergency alerts (EEAs), no load shedding occurred, and SPP was not directly mentioned in any of the recommendations.

SPP was not a BA at the time of the 2011 event, but due to SPP's current NERC registrations as a BA, planning coordinator (PC), transmission planner (TP), reliability coordinator (RC), reserve sharing group (RSG) and transmission service provider (TSP), a number of the recommendations were considered for potential improvements to SPP's operational and planning processes. Some recommendations are specific to the Electric Reliability Council of Texas (ERCOT) and WECC, but due to SPP's current NERC registrations, these were included as part of the comprehensive assessment.

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[27] https://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/SW_Cold_Weather_Event_Final.pdf

[28] https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

PLANNING AND RESERVES

The 2011 event report recommended that all entities responsible for the reliability of the bulk power system in the Southwest prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season. Recommendations included augmenting studies with scenarios like the 2011 winter conditions and changing operating practices to allow increased lead time for generator preparations, canceling previously scheduled outages and increasing reserves.

SPP conducts seasonal planning assessments as part of the integrated resource planning process. These assessments consider scenarios across a broad range of weather conditions, including seasonal generator capabilities. Extreme scenarios are included in NERC Transmission Planning Standards (TPL), Under-Frequency Load Shedding (UFLS) and annual transfer capability studies. SPP's planning criteria specifies generator testing requirements and generator owners and operators convey current information on seasonal capabilities including fuel switching, fuel supply and black-start capability.

SPP's staff works constantly to prepare for a range of expected and unexpected operational conditions by evaluating various scenarios based on short and midterm weather forecasts. These uncertainly levels are incorporated into the load and wind forecast outlook in the multiday resource availability assessments. Recommendations are provided to generator operators (GOPs) if early commitments are needed and SPP relies on the generators to make appropriate preparations, which can include pre-warming. SPP's personnel, processes, and systems have the ability to manage the clearing and delivery of operating reserves through reserve zones.

COORDINATION WITH GENERATOR OWNERS AND OPERATORS

Several recommendations involve coordination between transmission operators (TOPs), BAs and GOPs to develop mechanisms to verify generator capabilities such as fuel-switching, black-start capability and temperature performance. SPP's planning criteria includes testing requirements for generating units that incorporates seasonal parameters.

SPP also holds an annual winter preparedness workshop and transmission operators and generator operators typically give presentations on their upcoming winter preparedness. Attendees include members of SPP's ORWG. The 2020-2021 winter preparedness workshop was Sept. 29, 2020.

COMMUNICATIONS

This event highlighted the need for better communication about emergency situations between BAs, RCs and other market participants. SPP utilizes a number of communications including cold weather alerts, resource alerts and conservative operation notices. SPP's Reliability Communication Tool (R-COMM) is used to facilitate operator to operator communication between SPP and TOPs, BAs and RCs. The tool is also used by TOPs, BAs and RCs to communicate with SPP and each other.

ELECTRIC/GAS COORDINATION

This event highlighted many areas for improvement between the electric and gas industries. Recommendations included working with state regulators to adopt standards to winterize critical gas systems, allow critical gas systems to be exempt from load-shedding plans, and prioritize demands on gas supply. Electric/gas coordination requires engagement by numerous stakeholders at the federal and state level and across multiple agencies. After the 2011 event, SPP has been involved in efforts at the North American Energy Standards Board (NAESB) and NERC to improve coordination between the electric and gas industries.

- *North American Energy Standards Board*

  In both 2014 and 2016, NAESB undertook gas-electric harmonization (GEH) in response to a FERC directive. During that time, SPP worked with gas operators within our footprint to improve coordination and to make changes to the market bidding timeline.

- *North American Electric Reliability Corporation*

  SPP has been involved in the NERC Electric Gas Working Group who has been updating a guideline that includes recommendations to improve electric gas coordination. The guideline focuses on the areas of preparation, coordination, communication and intelligence that may be applied to improve gas and electric coordinated operations and minimize interdependent risks. The guidance is not a "one size fits all" set of measures but rather a list of principles and strategies that can be applied according to the circumstances encountered in a particular system, balancing authority, generator fleet or even an individual generator operator.

SOUTH CENTRAL COLD WEATHER EVENT JAN. 17, 2018

Below-average temperatures resulted in 183 individual generating units within the reliability coordinator footprints of SPP, Midcontinent Independent System Operator (MISO), Tennessee Valley Authority (TVA) and Southeastern Reliability Coordinator (SeRC) experiencing either an outage, a derate or a failure to start between Jan. 15-19, 2018. All of the recommendations from this event were reviewed, although a number of the recommendations were specific to MISO.

NERC RELIABILITY STANDARDS

The 2018 report recommended a three-pronged approach to ensure generator owners/generator operators, RCs and balancing authorities prepare for cold weather conditions, including the development of new or enhanced reliability standards. Recognizing the importance of the 2018 recommendations to improve operations, communication and coordination during extreme winter weather conditions, SPP sponsored the Standard Authorization Request (SAR) that led to NERC's winter weather reliability standard project. (Project 2019-06 Cold Weather.)

SPP led the industry's effort to finalize the SAR that was approved by NERC's Standard Committee. SPP chaired the Standard Drafting Team (SDT), and through NERC's collaborative process with interested stakeholders, the project recently received strong industry support. The project focuses on the first prong of the recommended approach and includes three revised reliability standards related to emergency preparedness (EOP-011-2), RC data specification and collection (IRO-010-4) and operational reliability data (TOP-003-5).

The NERC board of trustees adopted the project during a special session June 11, 2021, and authorized staff to file it with FERC.

SITUATIONAL AWARENESS

In the 2018 event report, FERC/NERC acknowledged that the relevant RCs (MISO, SPP, TVA and SeRC) had situational awareness throughout the event and communicated as necessary to preserve system reliability. However, four of the recommendations focused on situational awareness since the event involved large power transfers across four RCs. Performing additional studies and scenarios based on event conditions and conveying the results of the analysis to adjacent RC areas was recommended. Voltage stability studies were recommended, and SPP's voltage stability analysis tool became operational in mid-2018. SPP has implemented a process to identify additional study types for different constraint types that includes communication steps with adjacent RCs and impacted TOPs.

SPP and other RCs conduct capacity and energy drills on a periodic basis and system transfer scenarios are included in the training. The Jan. 17, 2018, State Estimator case was used to formulate customer training scenarios for six sessions in 2020. SPP will also conduct a pilot for the capacity and energy exercise for FERC to attend on Sept. 8, 2021, and the joint exercises with MISO on Sept. 23, 2021, and Oct. 7, 2021.

RC TO RC COMMUNICATIONS

To improve RC-to-RC communications, the 2018 report also made specific language change recommendations to the Regional Transfer Operating Procedures (RTOP). The recommendations were meant to provide more specificity to certain sections and improve communications related to Regional Directional Transfers and analysis of flow impacts. SPP is part of the Regional Transfer Operating Committee (RTOC) who owns the RTOP. Following the January 2018 event, the RTOC adopted modifications meeting the intent of the 2018 report recommendation, although some work remains.

SEASONAL STUDIES

The 2018 report recommended that RCs and PAs study more extreme conditions that include removing generators in their entirety, extreme condition load forecasting and benchmarking of actual events. The report also recommended that MISO and SPP perform seasonal transfer studies. SPP and MISO had calls in 2019 and 2020 to discuss worse case scenarios to be

included in seasonal studies. SPP and MISO coordinated and developed a few common scenarios for winter 2021 for multiple contingencies and extreme conditions (similar to Jan. 17, 2018) to identify constraints on seams that may be difficult to mitigate with normal congestion management processes. Operating guides were developed and reviewed with neighboring RCs and impacted TOPs. These scenarios will be provided to the training department for them to develop RC and TOP training including load shedding.

SYSTEM OPERATING LIMITS

This recommendation applied to the establishment of facility ratings by TOs and TOPs and the provision of those ratings to the RC for use in applications such as the Energy Management System (EMS) and Real-Time Contingency Analysis tools. SPP has a Rating Submission Tool used by TOPs to submit facility ratings. SPP staff reviewed this recommendation with RTO stakeholders in the Transmission Working Group (TWG) and ORWG to stress the importance of this recommendation.

RESERVES

The reserve recommendations focused on the deliverability of reserves, and MISO's communication with other RCs when it needs to rely on any amount of nonfirm, as available portion of the Regional Directional Transfer (RDT) to meet its reserves. All BAs have deliverability assurance processes in place. SPP has reserve zones modeled in the SPP Market System and can use those as needed. SPP staff reviews market solutions daily and this includes looking for stranded reserves. MISO and SPP's RCs communicate often during abnormal operating conditions and when MISO is depending on RDT to meet reserves.

LOAD FORECASTING

The load-forecasting recommendations were specific to MISO; however, their forecasting team reached out to SPP and staff reviewed load forecasting best practices. MISO is working on a forecasting survey with other ISOs/RTOs and will share the results with SPP upon completion.

SUMMARY

SPP is committed to identifying and improving our own processes and quickly initiated a comprehensive assessment of the February 2021 event, including a review of FERC and NERC recommendations from past winter events. We have determined SPP's current processes and tools encompass the majority of recommendations from the 2011 and 2018 events.

FERC and NERC began a review of the 2021 event on Feb. 16, 2021, and the results of the inquiry are not expected until this fall. SPP will review the recommendations from the inquiry and if not previously self-identified, will evaluate for inclusion in our implementation plan(s).

It is unknown at this time whether NERC or NAESB will undertake projects to improve electric-gas coordination or develop new or revised standards as a result of the 2021 event, but SPP will engage in projects as appropriate to improve the reliability of the bulk power system during extreme events.

APPENDIX E: COMMUNICATIONS SURVEY OF RSC AND CAWG MEMBERS

EXECUTIVE SUMMARY

The SPP communications department launched the RSC - Winter Storm Event Survey March 30, 2021, and closed the survey April 9, 2021. Staff distributed survey invitations to the 10 members of the Regional State Committee (RSC), the 11 members of the Cost Allocation Working Group (CAWG), and extended an invitation to complete the survey to the Texas Office of Public Utility Counsel (OPUC).

Ten RSC commissioners, nine members of the CAWG, and one member of the Texas OPUC completed the survey. The distribution of respondents by state is shown in Table 1.

On a scale of zero to four, with zero being "Highly Ineffective" and four being "Highly Effective," survey respondents gave an average rating of 2.95 when rating SPP's overall effectiveness during the winter storm event.

Table 1: Respondents by State

State	Respondents
Arkansas	2
Iowa	2
Kansas	2
Louisiana	2
Missouri	1
Nebraska	2
New Mexico	2
North Dakota	2
Oklahoma	2
South Dakota	2
Texas	1

Table 2: Overall Effectiveness

Q1. How would you rate the overall effectiveness of SPP's communication during the winter storm event?		
Respondent Type	**Average Rating**	**Equivalent Score**
Commissioners (10)	3.00	Effective
CAWG representatives (9)	2.88	Effective
Other (Texas OPUC, 1)	3.00	Effective
All Respondents	**2.95**	**Effective**

For individual categories of communication performance, the lowest ratings were given to the performance of SPP's members, and to assessments of how SPP and its members shared responsibility of communication with government and regulatory officials.

Some of the themes staff identified in open-ended responses were: a desire to improve advance notification, a need for more consistent communication from SPP and members, a need for clear sources of information and points of contact, a desire to improve the frequency of communication during an event, a need for more collaboration to reach overlapping audiences, and an opportunity to educate regulators, members and the public about these types of emergency events and how to respond.

SURVEY RESULTS BY QUESTION

The survey asked respondents to their agreement with the following statements below.

Q4: SPP's communication during the winter storm event was timely.

	Response percent	Response total
Strongly Agree	15%	3
Agree	65%	13
I don't know	5%	1
Disagree	15%	3
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q5: SPP communicated with appropriate frequency during the winter storm event.

	Response percent	Response total
Strongly Agree	10%	2
Agree	60%	12
I don't know	15%	3
Disagree	15%	3
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q6: Communication from SPP during the winter storm event was clear and understandable.

	Response percent	Response total
Strongly Agree	15%	3
Agree	70%	14
I don't know	5%	1
Disagree	10%	2
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q7: SPP effectively used a variety of communication methods (email, press releases, webinars, phone calls, website updates and social media) during the event.

	Response percent	Response total
Strongly Agree	20%	4
Agree	40%	8
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q8: SPP's leadership demonstrated necessary knowledge and expertise during the event, and were consistent in the delivery of their message.

	Response percent	Response total
Strongly Agree	25%	5
Agree	65%	13
I don't know	5%	1
Disagree	5%	1
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q9: SPP's communications clearly explained the actions stakeholders should take during the winter storm event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	50%	10
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	5%	1

Statistics based on **20** respondents;

Q10: SPP's communications during the event increased my trust in the credibility of SPP.

	Response percent	Response total
Strongly Agree	10%	2
Agree	45%	9
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	5%	1

Statistics based on **20** respondents;

Q11: SPP staff were available and willing to answer my questions during the event.

	Response percent	Response total
Strongly Agree	25%	5
Agree	45%	9
I don't know	30%	6
Disagree	0%	0
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q12: SPP's member organizations effectively communicated actions they were taking during the winter storm event.

	Response percent	Response total
Strongly Agree	15%	3
Agree	25%	5
I don't know	25%	5
Disagree	20%	4
Strongly Disagree	15%	3

Statistics based on **20** respondents;

Q13: SPP and its member organizations effectively shared responsibility for communicating with regulators during the event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	25%	5
I don't know	40%	8
Disagree	20%	4
Strongly Disagree	10%	2

Statistics based on **20** respondents;

Q14: SPP and its member organizations effectively shared responsibility for communicating with other elected officials during the event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	15%	3
I don't know	75%	15
Disagree	0%	0
Strongly Disagree	5%	1

Statistics based on **20** respondents;

APPENDIX F: COMMUNICATIONS SURVEY OF STAKEHOLDERS

SURVEY RESULTS BY QUESTION

Q1. Which of the following applies to you? (check all that apply)		
Respondent Type	**#**	**%**
Communications staff at an SPP member organization	31	20%
Government affairs staff at an SPP member organization	22	14%
Regulatory staff at an SPP member organization	17	11%
Operational staff at an SPP member organization	45	29%
Market staff at an organization participating in SPP's Integrated Marketplace	15	10%
Roster member of an SPP working group or committee	58	37%
Members Committee member of SPP	25	16%
SPP board member	7	5%
SPP staff	0	0%

Communications staff at an organization that is not a member of SPP	2	1%
Other role at an organization that is not a member of SPP	4	3%
Other role at an SPP member organization	16	10%
Other	8	5%
All Respondents (155 respondents)	**250**	**100%**

Q1. In what state(s) does your organization operate?		
State	**#**	**%**
Oklahoma / OK	53	14%
Kansas / KS	46	12%
Nebraska / NE	40	10%
Texas / TX	33	9%
Arkansas / AR (and one response of "AK" probably intended to be "AR")	27	7%
Missouri / MO	27	7%
South Dakota / SD	25	7%
New Mexico / NM	22	6%
Iowa / IA	21	5%
Louisiana / LA	17	4%
Minnesota / MN	17	4%
North Dakota / ND	17	4%
Montana / MT	12	3%
Wyoming / WY	13	3%
Colorado / CO	9	2%
Arizona / AZ	1	0%
California / CA	1	0%
Nevada / NV	1	0%
Utah / UT	1	0%
All Respondents (152 respondents)	**383**	**100%**

Q3: How would you rate the overall effectiveness of SPP's communication during the winter storm event? (154 responses)

	Response percent	Response total
Highly Effective	13.64%	21
Effective	66.23%	102
Neutral	16.23%	25
Ineffective	2.6%	4
Highly Ineffective	1.3%	2

The survey asked respondents to their agreement with the following statements.

Q4: SPP's communication during the winter storm event was timely. (155)

	Response percent	Response total
Strongly Agree	23.87%	37
Agree	58.71%	91
I don't know	7.1%	11
Disagree	9.03%	14
Strongly Disagree	1.29%	2

Q5: SPP communicated with appropriate frequency during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	26.45%	41
Agree	54.84%	85
I don't know	9.03%	14
Disagree	8.39%	13
Strongly Disagree	1.29%	2

Q6: Communication from SPP during the winter storm event was clear and understandable. (155)

	Response percent	Response total
Strongly Agree	24.52%	38
Agree	56.77%	88
I don't know	10.32%	16
Disagree	7.74%	12
Strongly Disagree	0.65%	1

Q7: SPP effectively used a variety of communication methods (email, press releases, webinars, phone calls, website updates and social media) during the event. (155)

	Response percent	Response total
Strongly Agree	21.94%	34
Agree	54.84%	85
I don't know	17.42%	27
Disagree	5.16%	8
Strongly Disagree	0.65%	1

Q8: SPP's communications clearly explained the actions stakeholders should take during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	18.07%	28
Agree	50.32%	78
I don't know	18.71%	29
Disagree	10.97%	17
Strongly Disagree	1.94%	3

Q9: SPP communications during the event increased my trust in the credibility of SPP. (155)

	Response percent	Response total
Strongly Agree	20%	31
Agree	50.32%	78
I don't know	24.52%	38
Disagree	3.87%	6
Strongly Disagree	1.29%	2

Q10: SPP's leadership demonstrated necessary knowledge and expertise during the event, and were consistent in the delivery of their message. (155)

	Response percent	Response total
Strongly Agree	29.03%	45
Agree	58.71%	91
I don't know	8.39%	13
Disagree	3.23%	5
Strongly Disagree	0.65%	1

Q11: SPP staff were available and willing to answer my questions during the event. (155)

	Response percent	Response total
Strongly Agree	30.32%	47
Agree	41.94%	65
I don't know	27.1%	42
Disagree	0%	0
Strongly Disagree	0.65%	1

Q12: SPP's member organizations effectively communicated actions they were taking during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	8.39%	13
Agree	46.45%	72
I don't know	32.9%	51
Disagree	10.97%	17
Strongly Disagree	1.29%	2

Q13: SPP and its member organizations effectively shared responsibility for communicating with regulators during the event. (22 Respondents – this question was only available to respondents who indicated they were government affairs or regulatory staff)

	Response percent	Response total
Strongly Agree	9.09%	2
Agree	45.46%	10
I don't know	31.82%	7
Disagree	13.64%	3
Strongly Disagree	0%	0

Q14: SPP and its member organizations effectively shared responsibility for communicating with other elected officials during the event. (22 Respondents – this question was only available to respondents who indicated they were government affairs or regulatory staff)

	Response percent	Response total
Strongly Agree	13.64%	3
Agree	31.82%	7
I don't know	27.27%	6
Disagree	27.27%	6
Strongly Disagree	0%	0

SPP Southwest Power Pool

SPECIAL BOARD OF DIRECTORS/MEMBERS COMMITTEE MEETING

July 26, 2021

Agenda

2:00 p.m. – 5:00 p.m.

Board of Directors/Members Committee Special Meeting

1. Call to Order and Administrative Items..Mr. Larry Altenbaumer
2. 2021 February Winter Weather Event Report & Recommendations ....Mr. Lanny Nickell
3. GI Queue Backlog Clearing Recommendations...Mr. Antoine Lucas
4. Western New Member Terms & Conditions Recommendations .... Mr. Bruce Rew

Antitrust: SPP strictly prohibits use of participation in SPP activities as a forum for engaging in practices or communications that violate the antitrust laws. Please avoid discussion of topics or behavior that would result in anti-competitive behavior, including but not limited to, agreements between or among competitors regarding prices, bid and offer practices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that might unreasonably restrain competition.

A COMPREHENSIVE REVIEW OF SOUTHWEST POWER POOL'S RESPONSE TO THE FEBRUARY 2021 WINTER STORM

ANALYSIS AND RECOMMENDATIONS

By Southwest Power Pool

Published on July 19, 2021

Version 1.0

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EXECUTIVE SUMMARY

As a regional transmission organization (RTO) tasked with ensuring the reliable delivery of electricity to a 14-state region, Southwest Power Pool (SPP) experienced the most operationally challenging week in its 80-year history during Feb. 14-20, 2021. Many locations across the entire SPP service territory, from North Dakota to the Texas panhandle, experienced record-low temperatures for days on end. As consumers' use of electricity and natural gas increased in response to the cold, power producers simultaneously faced fuel-supply issues and equipment malfunctions, transmission system equipment approached unsafe operating limits, and the overall reliability of the bulk electric system was severely tested.

Despite the challenges of managing record wintertime electricity use, generation unavailability, fuel-supply issues, transmission congestion and historically high energy costs, SPP kept the lights on across its region throughout the winter storm, with two short exceptions. SPP directed its transmission operators (TOP) to curtail electricity use by temporarily interrupting their customers' electric service twice: once to lessen regional energy consumption by about 1.5% for 50 minutes Feb. 15 and again to lessen it by about 6.5% for a little more than three hours Feb. 16. Underscoring the historic significance of the February 2021 winter weather event, these marked the first times in the organization's history that SPP has called for regionwide curtailments.

In a special meeting of the SPP Board of Directors and Members Committee on March 2, 2021, the board directed a comprehensive review of SPP's and its stakeholders' response to the February storm. The review was organized to analyze operational, financial, communications and other aspects of the events of Feb. 14-20, and to identify how the organization can learn, adapt and be better prepared for future extreme threats to reliability.

Five teams were tasked with evaluating a multitude of factors related to the event, and a steering committee was formed[1]. The five teams' areas of focus, the stakeholder groups and other audiences who primarily contributed input to their reviews, and team leaders are summarized in the table below.

[1] The Comprehensive Review Steering Committee comprised each teams' leader plus board chair Larry Altenbaumer, Members Committee representatives Joe Lang (Omaha Public Power District) and Betsy Beck (Enel Green Power North America), SPP President and CEO Barbara Sugg, and SPP COO Lanny Nickell, who chaired the committee.

Table 1: Comprehensive review teams' focus areas, representation and leadership

REVIEW TEAM	FOCUS AREAS	STAKEHOLDER GROUPS REPRESENTED	TEAM LEAD
Operations	Operational reliability Balancing authority Market performance Resource adequacy Transmission planning	Markets and Operations Policy Committee, Operating Reliability Working Group, Market Working Group, Transmission Working Group, and Supply Adequacy Working Group	**Denise Buffington** MOPC chair, Evergy director of regulatory affairs **Joe Lang** Members Committee representative, Omaha Public Power District director of energy regulatory affairs
Finance	Settlement and credit issues	Finance Committee, Settlements User Forum, Credit Practices Working Group	**Tom Dunn** Finance Committee staff secretary, SPP chief financial officer **Betsy Beck** Members Committee representative, Enel Green Power North America director, organized markets
Communications	Protocols and coordination related to operational, stakeholder, governmental and public communications	Communications representatives from stakeholder organizations	**Mike Ross** SPP senior vice president of government affairs and public relations
Regional State Committee	Resource adequacy and cost allocation	Regional State Committee, Cost Allocation Working Group	**Commissioner Kristie Fiegen** Regional State Committee president, South Dakota Public Utilities commissioner
Market Monitoring Unit	Actual gas costs for settlements purposes Market behavior and rules issues How the markets worked overall	Independent review	**Keith Collins** SPP MMU executive director

This report represents the findings and recommended directional objectives generated during the comprehensive review, as consolidated, synthesized and summarized by SPP staff. A report produced by SPP's independent Market Monitoring Unit (MMU) is published separately and is available on SPP.org along with other MMU reports.

KEY OBSERVATIONS

The comprehensive review yielded seven key observations regarding the root causes of the winter storm's impact, SPP's response and its preparedness to respond to future reliability events.

1. The unavailability of generation, driven mostly by lack of fuel, was the largest contributing factor to the severity of the winter weather event's impacts[2], which was exacerbated by record wintertime energy consumption[3] and a rapid reduction of energy imports[4].

   This root cause drives the need to develop policies that improve fuel assurance and resource adequacy and highlights the need to further assess SPP's ability to reliably operate the system with more intermittent and fewer base-load resources. Better coordination and communication between the gas and electric industries could have significantly improved preparation activities.

2. Extremely high natural gas prices were the primary driver of record-high energy offers that exceeded the FERC-required offer cap of $1,000/megawatt-hour (MWh) for the first time in SPP's market history. On Feb. 15, SPP's market price reached an all-time high of $4,274.96/MWh in the day-ahead market. By comparison, the average price of energy in SPP's day-ahead market for the entire year of 2020 was $17.69/MWh. Natural gas markets are not subject to price or offer caps, while electricity markets like SPP's are.

3. The rapid spike in SPP's market prices resulted in an immediate concern about liquidity of market participants and created an exponential increase in short-term credit exposure.[5]

[2] Up to approx. 59,000 MW of generating nameplate capacity in SPP was unavailable to meet demand during the week of the event. When generation was most needed on Feb. 16, about 30,000 MW of generating capacity was unavailable due to forced outages. The largest single cause of these forced generation outages was attributed to fuel-supply issues, causing nearly 47% of the outages and affecting over 13,000 MW of gas generation.
[3] SPP set a new winter peak load of 43,661 MW the morning of Feb. 15 and likely would have reached a wintertime peak of 47,000 MW if not for conservation and curtailments.
[4] Reductions in imports were due to transmission congestion and tightening supply conditions in neighboring areas. Between 2,000 and 2,500 MW of imports were quickly reduced on both Feb. 15 and 16, contributing to SPP's need to shed load each day.
[5] SPP sought and received a waiver from FERC extending the cure period for load serving entities to satisfy calls for financial security.

4. Relationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event, with net amounts exceeding 6,000 megawatts (MW) at times. This emphasizes the value these relationships and robust transmission interconnections provide during emergency events and the opportunity to further strengthen them.

5. The SPP transmission system was highly congested at times during the event with limitations that prevented full use of generation available in certain locations.[6] This issue exacerbated SPP's need to achieve balance between regional supply and demand through use of its load-shed procedures and raised questions about the appropriateness of regionally allocating load-shed responsibilities.

6. Early preparation, timely decisions and effective communication helped minimize the winter storm's impact on reliability. Early communication of a public appeal for conservation contributed to reduced demand Feb. 15, reducing the amount of controlled service interruptions required. Effective communication of and prompt response to load-shed instructions likewise mitigated the risk of uncontrolled blackouts.

7. SPP's stakeholders indicated general satisfaction with SPP's emergency communications, information sharing and credibility related to the winter storm response, although some areas of improvement were identified, particularly in those related to end-use customer awareness.

More on these key observations and related issues can be found in the following sections provided later in this report:

- Analysis of Operations and Market Performance
- Analysis of Finance, Settlements and Credit
- Analysis of Communications

RECOMMENDATIONS

Throughout the comprehensive review, SPP staff and stakeholders evaluated hundreds of potential process changes, system enhancements, new and amended policies, further assessments, and other potential solutions meant either to address the root causes of the February 2021 event's impact on the SPP system or to better enable SPP and its stakeholders to respond to future extreme system events. Ultimately, this report recommends 22 actions, policy changes and assessments categorized in three tiers[7] according to urgency, importance, impact

[6] SPP experienced 54 transmission constraints at the time load shedding began Feb. 16 that resulted in nearly 1,900 MW of generation being reduced to maintain reliable energy flows on those facilities.
[7] Of these 22 recommended objectives, four are tier 1, thirteen are tier 2 and five are tier 3.

and other factors. Full implementation of many of these recommendations will be subject to further approvals as prescribed by SPP bylaws.

Recommendations are categorized according to a three-tier ranking system defined as follows:

- **Tier 1:** Recommended actions, policies or assessments deemed necessary and urgent to avoid severe reliability, financial, operational, compliance or reputational risks.

  These recommendations are expected to address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts.

  Upon board approval, work associated with implementation of these recommendations shall be prioritized by the organization at the highest level and begin immediately.

- **Tier 2:** Recommended actions, policies or assessments deemed necessary to minimize the risk of severe reliability, financial, operational, compliance or reputational consequences associated with extreme system events.

  These recommendations may not address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts, but are important, are expected to significantly improve SPP's response to extreme system events in the future, and shall be treated as high-priority initiatives.

- **Tier 3:** Recommended actions, policies or assessments that would improve SPP's response, communications and public perception during extreme system events, but are not urgent.

Recommendations are also categorized into one of three possible types, defined as follows:

- **Action**: Development and/or implementation of a new process, requirement, protocol or other activity.

- **Policy**: Development of principles to be used to guide subsequent development of requirements, protocols, and/or processes using the stakeholder process in accordance with bylaws, tariff provisions and applicable regulations.

- **Assessment**: Performance of analysis that informs development of solutions through the stakeholder process.

FUEL ASSURANCE

Table 2: Summary of recommendations to the board related to fuel assurance

#	TIER	CATEGORY	RECOMMENDATION
FA 1	1	Policy	Develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region.
FA 2	1	Assessment	Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events.
FA 3	2	Policy	Develop policies to improve gas-electric coordination that better inform and enable improved emergency response.

RESOURCE PLANNING AND AVAILABILITY

Table 3: Summary of recommendations to the board related to resource planning and availability

#	TIER	CATEGORY	RECOMMENDATION
RPA 1	1	Assessment	Perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix.[8]
RPA 2	1	Policy	Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives[9] that ensure sufficient resources will be available during normal and extreme conditions.

[8] The Holistic Integrated Tariff Team's (HITT) recommendation R1 should be considered when addressing RPA 1.
[9] HITT recommendation R2 should be considered when addressing this part of RPA 2.

EMERGENCY RESPONSE PROCESSES AND PLANNING

Table 4: Summary of recommendations to the board related to emergency response processes and planning

#	TIER	CATEGORY	RECOMMENDATION
ERP 1	2	Assessment	Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations.
ERP 2	2	Action	Implement improvements to load-shed processes to be developed by the Operating Reliability Working Group (ORWG), such as: • Utilize real-time load values when determining load-shed ratio shares. • Train and drill on multiple overlapping load-shed instructions. • Perform a detailed review of models used to determine load-shed ratio shares. • Develop and document procedures and processes to address the timing and responsibility of curtailing exports before and during a load-shed event.
ERP 3	2	Policy	Develop a policy to ensure TOP emergency response and load-shed plans have been reviewed, updated and tested on an annual basis to verify their effectiveness, with attention to critical infrastructure.

OPERATOR TOOLS, COMMUNICATION AND PROCESS

Table 5: Summary of recommendations to the board related to operator tools, communications and processes

#	TIER	CATEGORY	RECOMMENDATION
OTCP 1	2	Action	Develop or enhance the tools, communications and processes identified by the ORWG and needed to improve SPP and stakeholder response to extreme conditions, such as: • Enhance real-time cascading analysis studies and post results. • Develop tool(s) to increase operator awareness of Out of Merit Energy (OOME) instructions. • Enhance and expand the use of R-Comm.[10] • Create a reliability dashboard to improve situational awareness for operators. • Utilize member-maintained distribution lists for communications purposes. • Develop a process to update operations management during extreme conditions.

[10] R-Comm is the Reliability Communications tool, the primary means of communication for responsible entities to receive, acknowledge and carry out load-shed instructions issued by the SPP Balancing Authority.

SEAMS AGREEMENTS

Table 6: Summary of recommendations to the board related to seams agreements

#	TIER	CATEGORY	RECOMMENDATION
SEAMS 1	2	Action	Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance and fairly compensate emergency energy.

MARKET DESIGN

Table 7: Summary of recommendations to the board related to market design

#	TIER	CATEGORY	RECOMMENDATION
MKT 1	2	Policy	Develop and improve policies to ensure price formation and incentives reflect system conditions.
MKT 2	2	Action	Develop and implement market design and market-related enhancements identified by the Market Working Group to improve operational effectiveness and ensure governing language provides needed flexibility and clarity, such as: • Improve the Dispatch Target Adjustment Process. • Enhance the Multiday Reliability Assessment Process.[11]
MKT 3	2	Policy	Develop policies to ensure financial outcomes during emergency conditions are commensurate with the benefits provided.

TRANSMISSION PLANNING

Table 8: Summary of recommendations to the board related to transmission planning

#	TIER	CATEGORY	RECOMMENDATION
TXP 1	2	Policy	Develop policies that facilitate transmission expansion needed to improve SPP's ability to more effectively utilize the transmission system during severe events.
TXP 2	3	Policy	Develop transmission planning policies that improve input data, assumptions or analysis techniques needed to better account for severe events.

[11] HITT recommendations R3 and R4 should be considered when addressing MKT 2.

CREDIT AND SETTLEMENTS

Table 9: Summary of recommendations to the board related to credit and settlements

#	TIER	CATEGORY	RECOMMENDATION
CR 1	2	Assessment	Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in the first quarter of 2022.
CR 2	3	Assessment	Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes.
CR 3	3	Action	Clarify tariff language related to SPP's settlements and credit-related authorities and responsibilities.

COMMUNICATIONS

Table 10: Summary of recommendations to the board related to communications

#	TIER	CATEGORY	RECOMMENDATION
COMM 1	2	Action	Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: • Processes that ensure stakeholders have a dependable way to receive timely, accurate and relevant information regarding emergencies. • Plans to drill emergency communications procedures with all relevant stakeholders. • Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers, and government entities and stay up-to-date.
COMM 2	2	Assessment	Evaluate and propose needed enhancements to communications tools and channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc.
COMM 3	3	Action	Form a stakeholder group whose scope would include discussion of matters related to emergency communications.
COMM 4	3	Action	To increase public awareness of and satisfaction with SPP, develop materials intended to educate general audiences on foundational electric utility industry concepts and SPP's role in ensuring electric reliability.

COMPREHENSIVE REVIEW PROCESS

SPP's comprehensive review of the February 2021 winter weather event included input from SPP staff and representatives of stakeholder groups including members, market participants, SPP's independent market monitor, regulators, elected officials and members of the media, among others. A steering committee was formed to ensure coordination and communication among parallel efforts conducted by the five teams identified below. Members of the steering committee were:

Lanny Nickell, Chair (SPP chief operating officer)

Larry Altenbaumer (Chair of the SPP Board of Directors)

Barbara Sugg (SPP president and chief executive officer)

Betsy Beck: Finance review co-lead (Members Committee representative, Enel Green Power North America director, organized markets)

Denise Buffington: Operations review lead (Evergy director of regulatory affairs)

Keith Collins: Market monitoring review lead (Executive director of SPP Market Monitoring Unit)

Tom Dunn: Finance review lead (SPP chief financial officer)

Kristie Fiegen: Regional State Committee review lead (South Dakota Public Utilities commissioner)

Joe Lang: Operations review co-lead (Members Committee representative, OPPD director of energy regulatory affairs)

Mike Ross: Communications review lead (SPP senior vice president of government affairs and public relations)

Reporting to the steering committee were five teams tasked with performing their own evaluations of various aspects of the February winter weather event's impacts. Each team's roster and scope are identified below along with notes regarding their evaluation process and/or outcomes.

OPERATIONS REVIEW

Four of SPP's working groups reviewed the event to develop recommendations: the Market Working Group (MWG), Operating Reliability Working Group (ORWG), Supply Adequacy Working Group (SAWG) and Transmission Working Group (TWG).

Operations Review Leads

Denise Buffington, chair
Evergy, SPP MOPC chair

Joe Lang
Omaha Public Power District

Market Working Group

Richard Ross, MWG chair
American Electric Power-Southwestern Electric Power

Jim Flucke, MWG vice chair
Evergy Companies

Erin Cathey, MWG staff secretary
SPP

Aaron Rome
Midwest Energy

Betsy Beck
Enel Green Power North America

Carrie Dixon
Xcel Energy

Chandler Brown
Sunflower Electric Power Corporation

Eric Alexander
Grand River Dam Authority

Jack Clark
NextEra Energy Resources

Jack Madden
East Texas Electric Cooperatives

John Varnell
Tenaska Power Services

Lee Anderson
Lincoln Electric System

Michael Massery
Arkansas Electric Cooperative Corporation

Neal Daney
Kansas Municipal Energy Agency

Rick Yanovich
Omaha Public Power District

Shawn Geil
Kansas Electric Power Cooperative

Shawn McBroom
Oklahoma Gas and Electric

Valerie Weigel
Basin Electric Power Cooperative

Yohan Sutjandra
City Utilities of Springfield

Operating Reliability Working Group

Allen Klassen, ORWG chair
Evergy Companies

Ron Gunderson, ORWG vice chair
Nebraska Public Power District

Zachary Sharp, ORWG staff secretary
SPP

Abubaker Elteriefi
ITC

Allan George
Sunflower Electric Power

Bryn Wilson
Oklahoma Gas & Electric

Chance Myers
Western Farmers Electric Cooperative

Chris Shaffer
American Electric Power

David Pham
The Empire District

Doug Peterchuck
Omaha Public Power District

Gary Plummer
Independence Power & Light

Jeff Wells
Grand River Dam Authority

Jim Useldinger
GridLiance High Plains

John Roemen
Western Area Power Administration

Keith Carman
Tri-State Generation and Transmission Association

Kyle McMenamin
Southwestern Public Service Company /Xcel Energy

Laurie Gregg
Lincoln Electric System

Mark Eastwood
City Utilities of Springfield

Matt Pawlowski
NextEra Energy Resources

Supply Adequacy Working Group

Natasha Henderson, SAWG chair
Golden Spread Electric Cooperative

Tom Hestermann, SAWG vice chair
Sunflower Electric Power Corporation

Chris Haley, SAWG staff secretary
SPP

Aaron Castleberry
Oklahoma Gas & Electric

Aaron Ramsdell
Basin Electric Power Cooperative

Adam Graff
Heartland Consumers Power District

Amy Newton
City Utilities of Springfield

Bennie Weeks
Xcel Energy Services

Brian Berkstresser
Liberty Utilities

Colton Kennedy
Omaha Public Power District

David Sonntag
Western Farmers Electric Cooperative

Eric Alexander
Grand River Dam Authority

Ernesto Perez
East Texas Electric Cooperative & Northeast Texas Electric Cooperative

Jeffrey Plew
NextEra Energy Resources

Jim Jacoby
American Electric Power-Public Service Co of OK

Jodi Knutson
WAPA

John Varnell
Tenaska Power Services

Robert Janssen
Dogwood Energy

Thomas Saitta
Kansas Municipal Energy Agency

Timothy Cerveny
Nebraska Municipal Power Pool

Traci Bender
Nebraska Public Power District

Walt Cecil, CAWG liaison
Missouri Public Service Commission

Transmission Working Group

Nathan McNeil, TWG chair
Midwest Energy

Derek Brown, TWG vice chair
Evergy Companies

Adam Bell, TWG staff secretary
Southwest Power Pool

Andrew Berg
Missouri River Energy Services

Arash Ghodsian
EDF Renewables Development

Chris Pink
Tri-State Generation and Transmission Association, Inc.

Clifford Franklin
Sunflower Energy

Gayle Nansel
Western Area Power Administration

James Ging
Kansas Power Pool

Jarred Cooley
Xcel Energy

Jason Shook
East Texas Electric Cooperative

Jim McAvoy
Oklahoma Municipal Power Authority

Joe Fultz
Grand River Dam Authority

John Boshears
City Utilities of Springfield, Missouri

John Knofczynski
East River Electric Power Cooperative

Joshua Verzal
Omaha Public Power District

Kalun Kelley
Western Farmers Electric Cooperative

Matthew McGee
American Electric Power

Michael Mueller
Arkansas Electric Cooperative Corporation

Michael Wegner
ITC Holdings

Nate Morris
Liberty Utilities

Noman Williams
GridLiance High Plains

Phil Westby
Basin Electric Power Cooperative

Randy Lindstrom
Nebraska Public Power District

Scott Benson
Lincoln Electric System

Shane McMinn
Golden Spread Electric Cooperative

Steve Hardebeck
Oklahoma Gas & Electric

SCOPE OF WORK

Immediately after the winter storm, SPP staff began analyzing the event. Staff prepared a draft report and shared it with members of the MWG, ORWG, SAWG and TWG. The report included information pertaining to operational activities and observations before and during the events.

The working groups met multiple times to review the draft event report and develop recommendations. The SAWG held six executive sessions to discuss the event and reviewed the recommendations at three regular meetings. The ORWG held 13 executive sessions dedicated to the event and discussed it at one regular meeting. The TWG held four executive sessions to discuss the event and reviewed recommendations at two regular meetings. The MWG held seven executive sessions dedicated to the event and discussed it at three regular meetings. The four groups held a joint executive session where all members could come together to collaborate.

FINANCIAL REVIEW

Staff from SPP's accounting, settlements and credit departments conducted SPP's financial analysis of the February 2021 winter weather event and validated their observations with the Finance Committee and Credit Practices Working Group.

Financial Review Leads

Tom Dunn, chair
SPP chief financial officer

Betsy Beck
Enel Green Power North America

SPP Staff

Brent Wilcox
SPP settlements

Dana Boyer
SPP settlements

Dianne Branch
SPP accounting

Don Shipley
SPP settlements

Jared Barker
SPP credit

Scott Smith
SPP credit

Steve White
SPP settlements

Tony Alexander
SPP settlements

Zeynep Vural
SPP accounting

Finance Committee

Susan Certoma, Chair
SPP Board of Directors

Sandra Bennett
American Electric Power

Julian Brix
SPP Board of Directors

Darcy Ortiz
SPP Board of Directors

Matt Pawlowski
NextEra Energy Resources

Sarah Stafford
OGE Energy

Al Tamimi
Sunflower Electric Power

Mike Wise
Gold Spread Electric Cooperative

Credit Practices Working Group

Caleb Head, CPWG chair
Northeast Texas Electric Cooperative

Mark Breese, CPWG vice chair
Xcel Energy

Seth Cochran
DC Energy

Tom Hestermann
Sunflower Electric Power Corporation

Mark Holler
Tenaska Power Services

LaGena O'Neal
Oklahoma Municipal Power Authority

Jason Regehr
City Utilities of Springfield, MO

Justin Riddell
The Energy Authority

Matthew Simon
Basin Electric Power Cooperative

Zachary Wegner
Omaha Public Power District

Terri Wendlandt
Evergy

SCOPE OF WORK

SPP's financial review focused on credit implications, settlement impacts and communication of financial matters as related to the February 2021 winter weather event. The observations and analysis detailed in the Analysis of Finance, Settlements and Credit section of this report are based on survey data, analysis of settlement disputes, the content of Request Management System tickets and settlement runs conducted by staff.

COMMUNICATIONS REVIEW

The Communications Comprehensive Review Team (CCR) comprised the following representatives of SPP and its stakeholder organizations. Its roster was intended to include individuals with responsibilities related to corporate communications, public relations, regulatory and government affairs and related fields, and to represent all of SPP's geographic regions and types of members.

Mike Ross, chair
SPP

Carl Stelly
SPP

CJ Brown
SPP

David Kimmel
OGE Energy

David Mindham
EDP Renewables

Derek Wingfield
SPP

Don Martin
SPP

Dustin Smith
SPP

Gina Penzig
Evergy

Jean Schafer
Basin Electric Power Cooperative

Jillian Janik
SPP

John McClure
Nebraska Public Power District

Kara Fornstrom
SPP

Kirkley Thomas
Arkansas Electric Cooperatives

Laura Lutz
Evergy

Lee Elliott
SPP

Leslie Sink
SPP

Lisa Meiman
Western Area Power Administration

Mark Becker
Nebraska Public Power District

Meghan Sever
SPP

Peter Main
American Electric Power/Southwestern Electric Power Company

Rae Rice
OGE Energy

Commissioner Randy Christmann
North Dakota Public Service Commission

Rob Roedel
Arkansas Electric Cooperatives

Russell Carey
SPP

Steve Gaw
Advanced Power Alliance

Tessie Kentner
SPP

Usha Turner
OGE Energy

Victor Schock
North Dakota Public Service Commission

SCOPE OF WORK

The CCR gathered documentation and data of relevant SPP communication from Feb. 4 through Feb. 20, and conducted an analysis of the processes, policies, staffing and resources used to conduct them. Analysis and recommendations covered four categories of communications:

- Operational communications.
- Stakeholder communications.
- Governmental and regulatory communications.
- Public communications (press, end-users and general public).

For each category, the CCR analyzed:

- What legal or standard requirements exist for SPP communication.
- How SPP's communication during the event met requirements.
- What procedures exist for additional communication.
- SPP's performance of internal procedures and processes.
- Communication performed by peers during the event.
- Other communication needs (perceived ⁄ expressed ⁄ relative) of operators, stakeholders, government and the public related to the event.

For each category, the CCR made recommendations to improve:

- *Internal* communication processes:
  - Interdepartmental communication.
  - Flow and responsibility of communication.
  - Resources provided for communication.
- *External* communication processes:
  - Effectiveness and timeliness of external communication.
  - Inclusion in each type of communication.
  - Stakeholder-driven communication process improvement.
  - Education about RTO emergency procedures and processes.
- *Member-conducted* communication processes:
  - Resources provided to SPP members to aid in communication.
  - Recommendations for standardizing public appeals and other processes.

For topics beyond the timeline and scope of the comprehensive review process, the CCR made some recommendations for additional analysis and recommendations, including topics for organizational groups or task forces to address in the future.

REGIONAL STATE COMMITTEE REVIEW

The Regional State Committee (RSC) of state utility commissioners, along with its Cost Allocation Working Group (CAWG), reviewed the winter event.

Regional State Committee

Kristie Fiegen, RSC chair
South Dakota Public Utilities Commission

Randel Christmann, RSC vice chair
North Dakota Public Service Commission

Paul Suskie, RSC staff secretary
SPP

Andrew French
Kansas Corporation Commission

Dana Murphy
Oklahoma Corporation Commission

Dennis Grennan
Nebraska Power Review Board

Geri Huser
Iowa Utilities Board

Jefferson Byrd
New Mexico Public Regulation Commission

Mike Francis
Louisiana Public Service Commission

Scott Rupp
Missouri Public Service Commission

Ted Thomas
Arkansas Public Service Commission

Will McAdams
Public Utility Commission of Texas

Cost Allocation Working Group

Greg Rislov, CAWG chair
South Dakota Public Utility Commission

Victor Schock, CAWG vice chair
North Dakota Public Service Commission

Lee Elliott, CAWG staff secretary
SPP

Adam McKinnie
Missouri Public Service Commission

Anna Hyatt
Iowa Utilities Board

Cindy Ireland
Arkansas Public Service Commission

Harika Basaran
Public Utility Commission of Texas

Jason Chaplin
Oklahoma Corporation Commission

John Krajewski
Nebraska Power Review Board

John Reynolds
New Mexico Public Regulation Commission

Lane Sisung
Louisiana Public Service Commission

Shari Albrecht
Kansas Corporation Commission

SCOPE OF WORK

RSC President Kristie Fiegen created the Cost Allocation Working Group Ad Hoc Task Force in response to the extreme weather event. The task force members were John Krajewski, John Reynolds and Shari Albrecht. The task force was charged with gaining a broad understanding of the factors that resulted in the emergency and developing recommendations related to the RSC's authority: cost allocation, financial transmission rights, resource adequacy and transmission planning for remote resources.

The task force interfaced with SPP staff, the MMU, the SAWG and the RSC in developing their recommendations. In total, the RSC review team held 32 meetings to discuss the event and develop recommendations.

The task force's report is posted on the SPP.org RSC page.

MARKET MONITORING UNIT REVIEW

Keith Collins, executive director of SPP's independent Market Monitoring Unit (MMU), led the MMU's review of the winter event. MMU staff invested a significant amount of effort into researching and analyzing what happened during the storm, including issues related to FERC Order No. 831, price formation, generation outages, scheduling and dispatch, and gas-electric coordination.

They engaged with the MWG, SAWG, ORWG, CPWG, CAWG, and communications review team to hear stakeholder concerns and discuss issues. The MMU held discussions with the Federal Energy Regulatory Commission and other independent system operators/regional transmission organizations regarding the event and related best practices.

The MMU's report and recommendations are posted to the MMU's page on SPP.org.

EVENTS OF FEB. 4-20

The winter weather event of February 2021 was historic in nature, requiring SPP to take steps to preserve the reliability of the regional power grid that it has not previously taken in its 80-year history. The entire SPP balancing authority (BA) region, stretching from the Canadian border in the north to the Texas panhandle in the south, was impacted by extreme cold temperatures that lasted days. This led to increased electricity use at the same time a number of factors limited generators' ability to produce power. Still, over the course of the week, SPP limited service interruptions to a total of just more than four hours spread over two days.

On the following pages are a timeline and review of the events leading up to, during and immediately following the winter storm. This report's appendices contain additional background information on subjects pertaining to SPP's role in managing regional reliability and preparing for winter-weather events like this one. See the appendices for information on these and other background topics:

- SPP's and its members' roles in assuring electric reliability
- Winter-weather preparation and training taken by SPP and stakeholder operations staff
- Industry standards related to SPP's and its members obligations during the winter weather event
- Findings and SPP's response to prior winter-weather reliability events in 2011 and 2018

The section titled Analysis of Operational and Market Performance presents a detailed evaluation and observations regarding the events described above.

Figure 1 is an illustrated timeline of SPP Balancing Authority operations from Feb. 4-20, 2021, followed by a high-level overview of five phases of the event: early forecasts, conservative operations, the declaration of a series of energy emergency alerts, controlled interruptions of service, and a period of lessening severity concluding with a return to normal operations. Note that time blocks in the following illustration are not to scale.

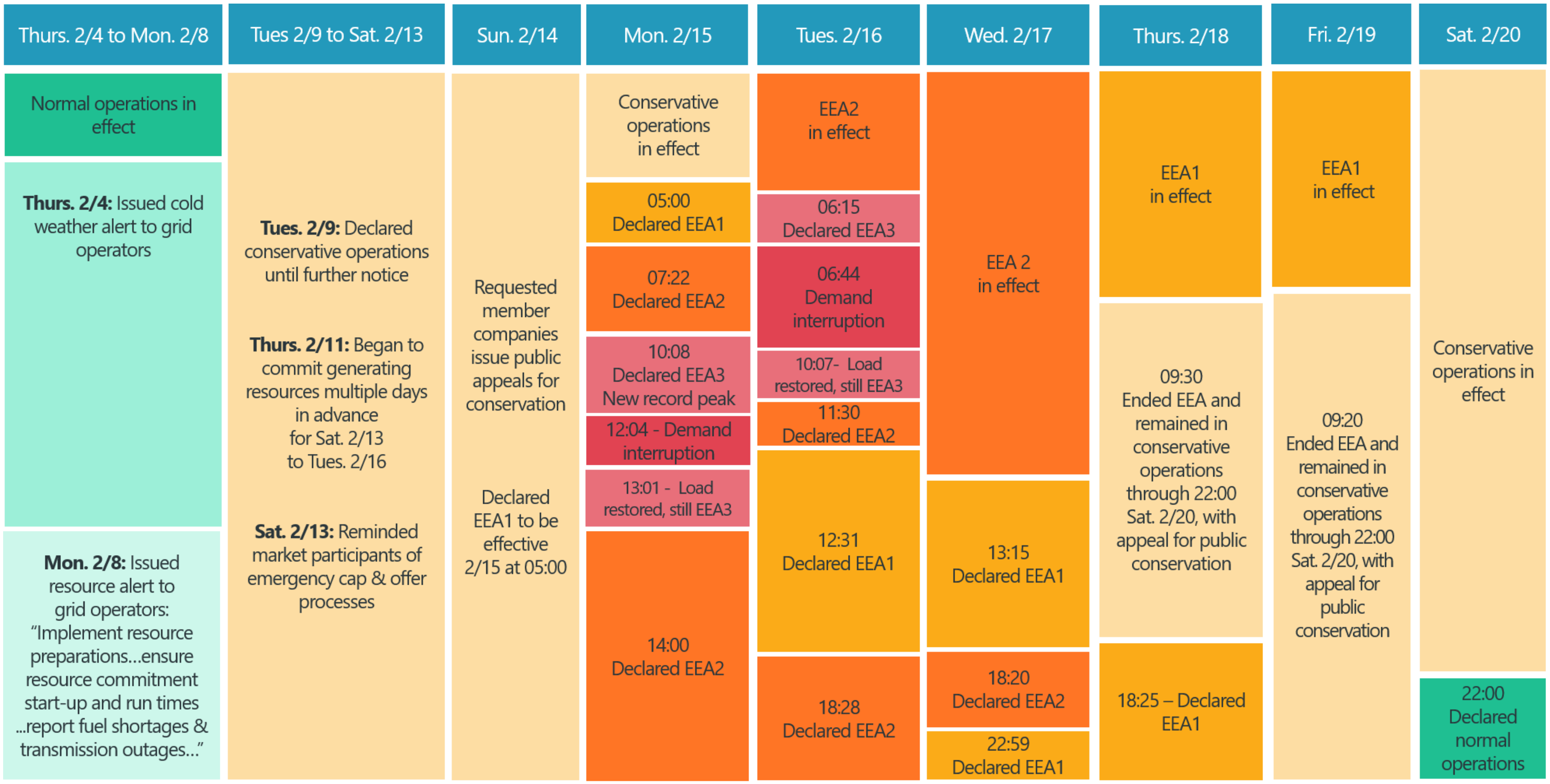

Figure 1: Timeline of BA Operations (Feb. 4-20, 2021)

REVIEW OF FEB. 4-20 ACTIVITIES

WEATHER

In February 2021, a major winter storm impacted the SPP region and much of the continental United States. On Feb. 14, the National Weather Service Prediction Center tweeted, "This cold snap is forecast to result in record low temperatures that are comparable to the historical cold snaps of Feb 1899 & 1905."[12] According to the National Operating Hydrologic Remote Sensing Center, on Feb. 16, about 73% of the mainland U.S. was covered in snow.[13] On Feb. 19, the National Weather Service tweeted that over 3,000 daily record cold temperatures had been reported, and within that dataset were 79 all-time cold records.[14]

The SPP region was inside the coldest portion of the continental U.S., as depicted in the following map.

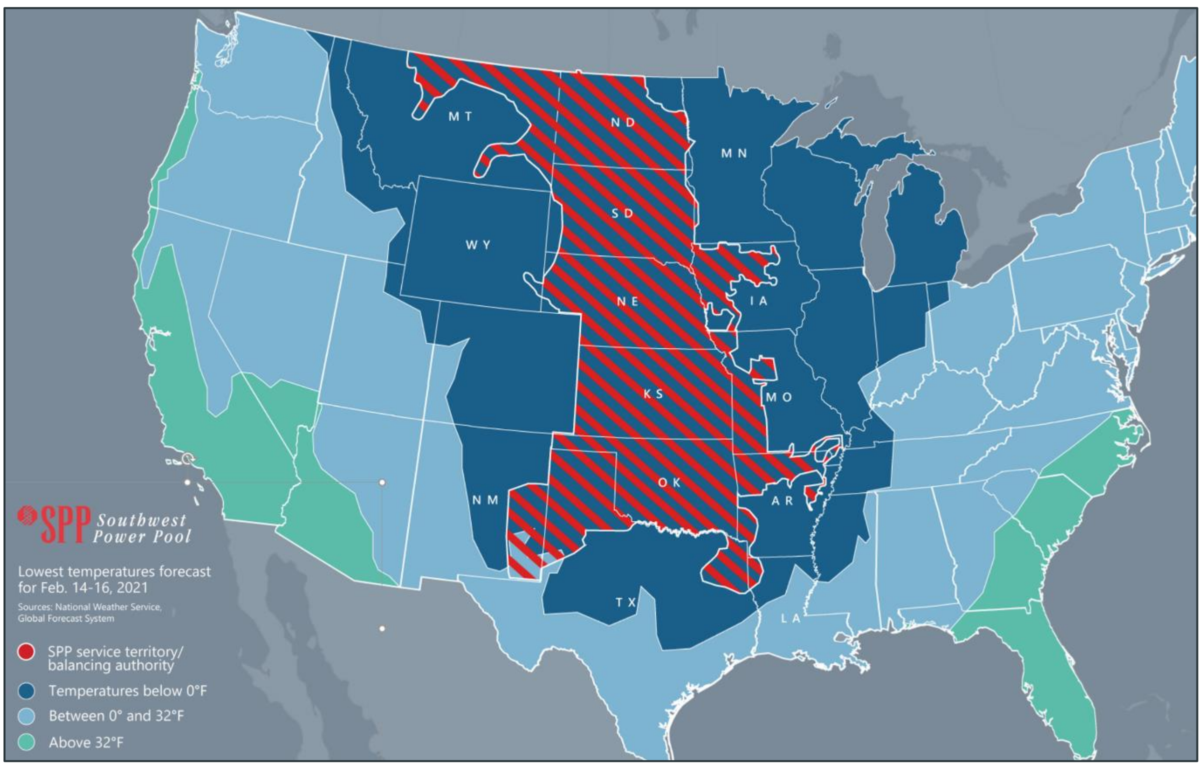

Figure 2: Low-Temperature Map

12 https://twitter.com/NWSWPC/status/1361000008519086085
13 https://www.nohrsc.noaa.gov/nsa/index.html?region=National&year=2021&month=2&day=16&units=e
14 https://twitter.com/NWSWPC/status/1362953109681672199

EARLY FORECASTS

First communication to member utilities about possible impacts of the winter storm occurred Feb. 4, 10 days before the storm hit.

1. **Feb. 4:** SPP issued a Cold Weather Alert effective Feb. 6. A Cold Weather Alert signals that forecasts anticipate extreme weather that could impact grid reliability.

2. **Monday, Feb. 8 at 10 a.m.**: SPP escalated status to Resource Alert. A Resource Alert signals that member utilities should implement resource preparations, ensure resource commitment startup and run times, and report fuel shortages and transmission outages that might impact normal operations.

CONSERVATIVE OPERATIONS AND OTHER PREPARATORY ACTIVITIES

3. **Tuesday, Feb. 9 at 12 a.m.**: SPP declared a period of Conservative Operations until further notice. SPP does this periodically when weather, environmental, operational or other events prompt us to operate the system conservatively to avoid an emergency.

4. **Thursday, Feb. 11**: SPP began committing generating resources using its multiday reliability assessment process. Instead of committing generation a day ahead, as is standard practice, SPP began sending instructions to generators several days in advance that they would be responsible for serving load for the period Saturday, Feb. 13 through Tuesday, Feb. 16.

ENERGY EMERGENCY ALERTS AND PUBLIC APPEALS

5. **Sunday, Feb. 14**

   a. **9:27 a.m.**: SPP emailed a declaration of an Energy Emergency Alert (EEA) Level 1 beginning Feb. 15, 2021, at 5 a.m. due to concerns regarding expected weather and fuel-supply issues.

   b. **1:57 p.m.**: SPP requested member utilities make public appeals for energy conservation effective beginning on Feb. 15.

   This marks the first time in SPP's history it has taken this step. A public appeal is a tool SPP has available to lessen electricity use when it forecasts that its generating capacity and reserves are at risk. A public appeal for conservation precedes service interruptions by calling for voluntary reductions, in hopes it will prevent the need for mandatory curtailments.

6. **Monday, Feb. 15 at 5 a.m.:** The SPP BA entered EEA Level 1 for its entire region. EEA Level 1 signals that all available generation is in use.

   Due to the expected severity of this winter storm's impacts, SPP had already issued a public appeal for conservation by this time. Public appeals typically follow an EEA Level 1, but SPP determined if public conservation were to have the desired effect, it would have to be done quickly. The decision proved beneficial: Actual load came in under forecast, at least partly because people responded and used less electricity than predicted.

7. **Monday, Feb. 15 at 7:22 a.m.:** SPP escalated to EEA Level 2. This marks the first time it had ever done so for its entire region.

   EEA Level 2 indicates that in addition to using all available generation, operating reserves are at risk of dropping below minimum requirements. It is at this point SPP typically would direct public appeal for conservation, but it had already done so given the extreme conditions the SPP BA region faced.

8. **Monday, Feb. 15 at 8:58 a.m.:** Even as load came in under forecast, SPP set an all-time peak of 43,661 megawatts (MW) for systemwide electricity use in winter across its region. This underscores the historic nature of this event: Even while using tools like voluntary conservation appeals, SPP still set a new winter peak.

9. **Monday, Feb. 15 at 10:08 a.m.:** SPP declared its first-ever regionwide EEA Level 3, the most severe of three EEA levels.

   EEA Level 3 indicates energy reserves have dropped below minimum requirements, meaning SPP has to find additional generation — by importing it or bringing another plant online — or lessen regionwide electricity use to keep the system in balance.

CONTROLLED INTERRUPTIONS OF SERVICE

10. **Monday, Feb. 15 at 12:04 p.m.:** Two hours after declaring an EEA Level 3, and having exhausted all other options, SPP directed member utilities to deliberately curtail region's energy use by 1.5%. This controlled interruption of service (also called a "load-shed event" lasted 57 minutes.

    When SPP directs controlled interruptions, it spreads their impacts across the whole region. For example, if demand exceeds supply by 100 MW, SPP asks each transmission operator (TOP) throughout the region to decrease electricity use by a proportional share to bring the whole system back into balance. The most load a single TOP was asked to shed during this interruption was 101 MW, or about 17% of the total by which we needed to lessen regional energy use at the time.

    It's up to each TOP to determine how to lessen its use, whether by curtailing residential, commercial or industrial load. SPP has no visibility into and has no authority to direct

how utilities lessen their load. In other words, there's no way for SPP to see or direct whether that reduction comes from particular homes, neighborhoods, farms, businesses, factories, etc. SPP simply monitors the aggregate impact of TOPs' actions to ensure the reliability of the regional grid.

11. **Monday, Feb. 15 at 1:01 p.m.**: SPP restored all load, bringing an end to the period of controlled interruptions of service that began at 12:04 p.m.

12. **Monday, Feb. 15 at 2 p.m.:** SPP declared an EEA Level 2, having restored minimum reserves, and remained in an EEA Level 2 for the duration of that day.

13. **Tuesday, Feb. 16**: The region's electricity use rose again during the typical morning peak — a natural occurrence as people woke up, raised their thermostats, began using appliances, went to work, etc.

14. **Feb. 16 at 6:15 a.m.:** SPP declared a second EEA Level 3.

15. **Feb. 16 at 6:44 a.m.:** SPP directed its member TOPs to implement controlled interruptions of service for a second time.

    The second interruption of service lasted three hours and 21 minutes and was required to lessen regional electricity use by 6.5%. As before, SPP spread the impact out across the region, asking TOPs to decrease their use by a proportional share of this total 6.5% reduction. The most a single entity had to shed in this event was about 227 MW, again about 17% of the total by which SPP needed to lessen total regional energy use.

16. **Feb. 16 at 10:07 a.m.:** SPP restored load, bringing an end to the second and final controlled interruption of service of the winter weather event.

RETURN TO NORMAL OPERATIONS

17. Throughout the remainder of the week, from **Tuesday, Feb. 16 at 11:30 a.m. until Friday, Feb. 19 at 9:20 a.m.**, SPP fluctuated between EEA Levels 1 and 2, de-escalating to Conservative Operations with no EEAs for several hours (9:30 a.m.-6:25 p.m.) on Thursday, Feb. 18.

18. **Saturday, Feb. 20 at 10 p.m.**: SPP declared an end to all applicable alerts and returned to normal operations.

EARLY GENERATION COMMITMENTS

Per the SPP BA Emergency Operating Plan, during a period of conservative operations, the SPP BA may take actions including the use of greater unit commitment notification timeframes, and making commitments prior to the day-ahead market (DAMKT) and/or committing resources in reliability status.

During the week of Feb. 7, SPP was notified of growing concerns about natural gas availability for the upcoming week. Staff worked to ensure all available resources were utilized.

SPP carried out several multiday Reliability Unit Commitment (RUC) studies, committing resources of various lead times well in advance of the DAMKT. These commitments were issued to give early notice that the resources would be needed in real time and that fuel should be procured accordingly. Figure 3 shows the amount of economic maximum capacity committed in each of the market's assessments, distinguished by case (i.e., the results of each assessment). The horizontal axis indicates the timeframe for which the commitments were made.

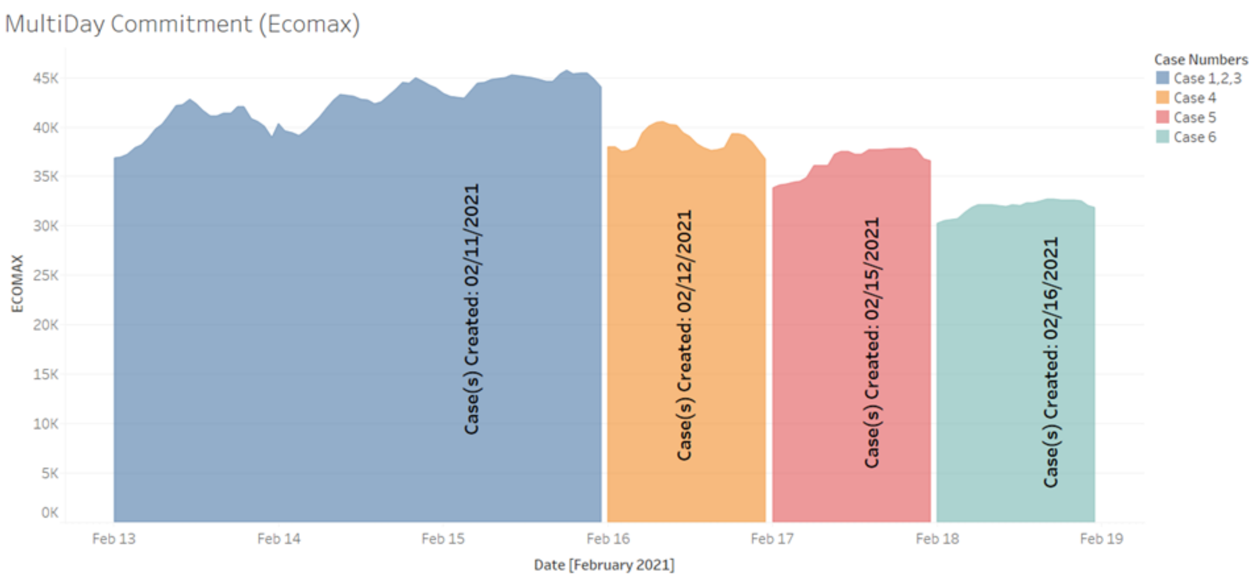

Figure 3: Multiday Commitment Cases

RESCHEDULED TRANSMISSION OUTAGES

Beginning Feb. 9, operations planning staff worked with TOPs to reschedule 134 transmission outages planned to take place Feb. 14-19. Figure 4 illustrates the number of outages rescheduled by kilovolt level. Outages that were previously implemented or were due to emergent work were not rescheduled. Approximately 130 transmission outages of various equipment types and voltage levels were ongoing throughout the event. Outages that were previously implemented or were due to emergent work were not rescheduled.

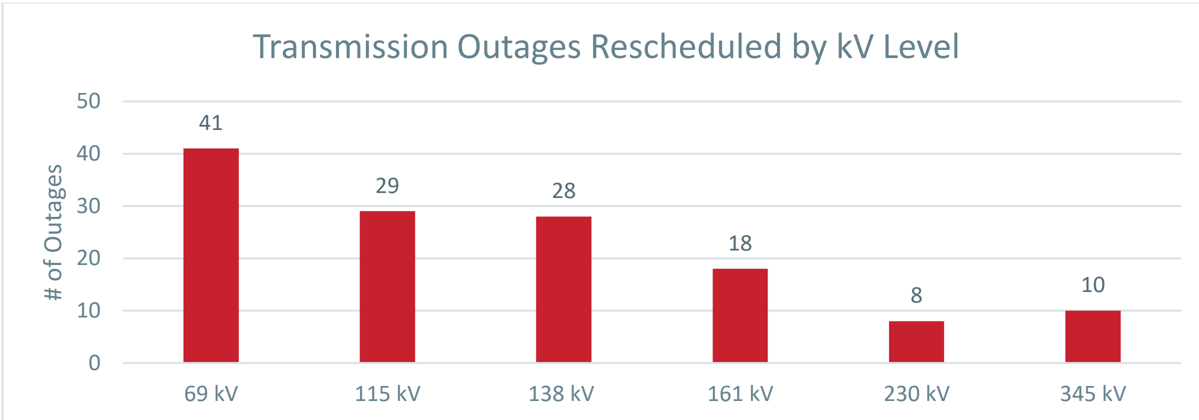

Figure 4: Rescheduled Transmission Outages (Feb. 14-19)

RESCHEDULED GENERATION OUTAGES

SPP allows a certain amount of planned generation outages on the system during the month of February. Over the last five years, planned generation outages during this time of year average around 6,000 MW. As shown in Figure 5, planned outages ran higher than normal during the early part of February but dipped below historical averages during the winter event.[15] This was primarily due to proactive efforts taken to reschedule planned maintenance.

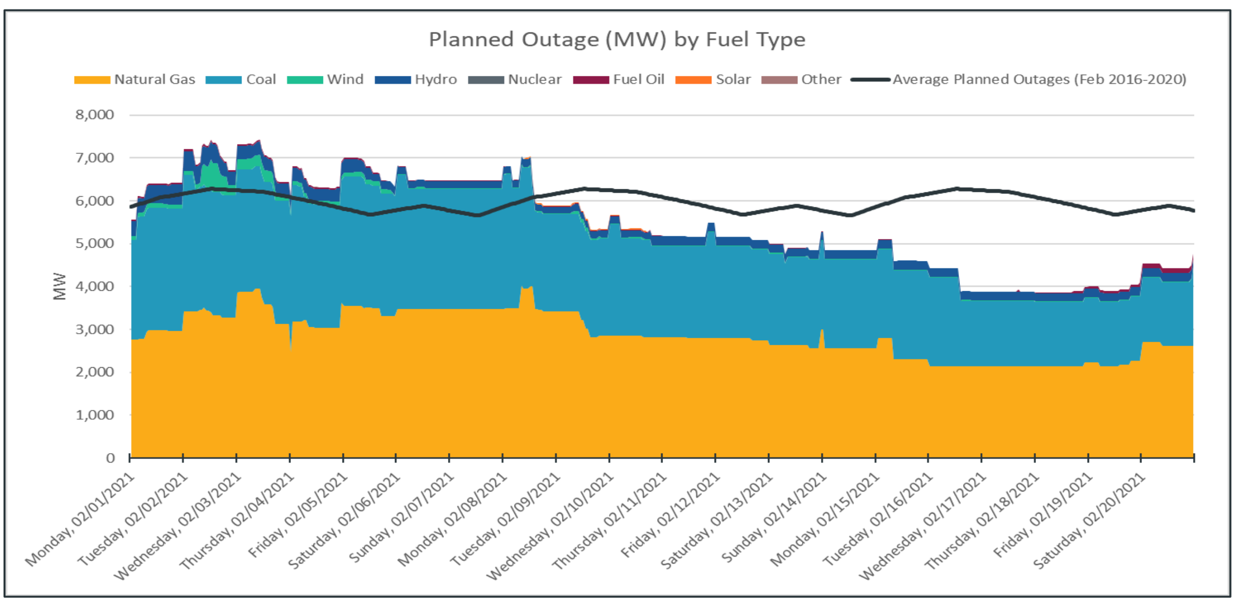

Figure 5: Planned Outages by Fuel Type (Feb. 1-20, 2021)

[15] Due to the nature of some planned outage maintenance, certain outages were not recallable during February 14-19.

Operations planning staff began working with GOPs on Feb. 9 to reschedule generation outages planned to take place Feb. 14-19. Outages that were previously implemented or were due to emergent work were not rescheduled. Resources in the midst of maintenance work may not have been recallable and maintained the original schedule.

Figure 6 illustrates the number of outages and associated capacity rescheduled by fuel type. The rescheduled outages account for roughly 4 gigawatts (GW) of generation capacity. The data includes outages that were canceled, moved or denied.

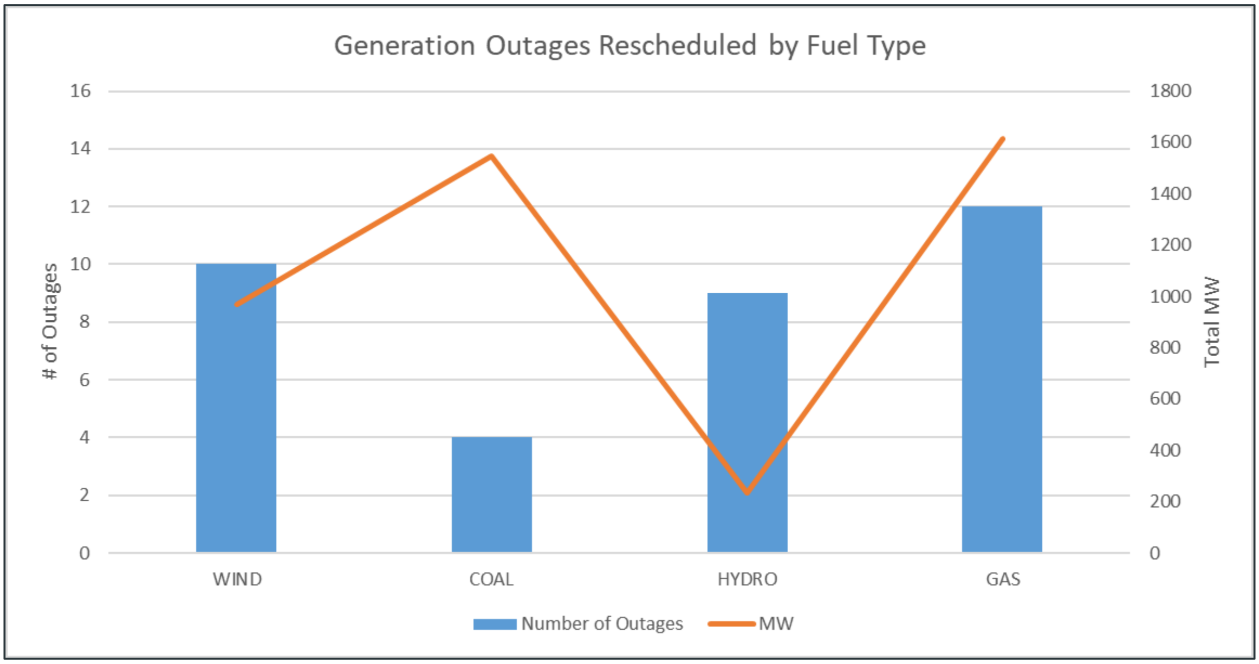

Figure 6: Rescheduled Generation Outages (Feb. 14-19)

LOAD

SPP experienced high winter load levels for multiple days leading up to Feb. 15. On the morning of Feb. 15, load reached 43,661 MW surpassing SPP's previous winter load peak of 43,584 MW set Jan. 17, 2018. It is noteworthy that this new winter load peak was reached Feb. 15 while SPP was taking actions, including issuing public requests for energy conservation, to reduce system load. SPP's midterm load forecasting applications projected load in excess of 44,000 MW for Feb. 15 and 47,000 MW for Feb. 16.

It is difficult to accurately determine how much higher SPP's system load may have been had load management procedures not been in effect during those times but it is likely SPP's previous winter load peak would have been surpassed by nearly 8% if sufficient generating resources had been available.

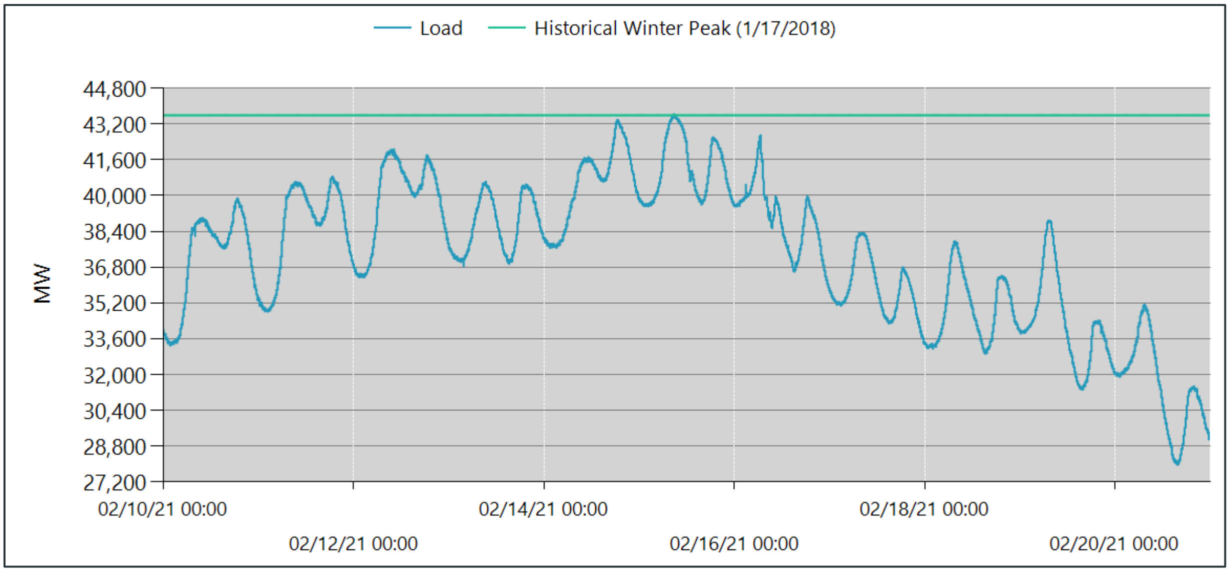

Figure 7: SPP BA load and historical winter peak

LOAD FORECASTING

The projected non-coincident peak load forecasted leading into the 2020-2021 winter season was approximately 43,700 MW. During the 2021 winter weather event, the SPP BA experienced a coincident peak demand of 43,661 MW. During this event, the highest forecasted day-ahead peak load was close to 46,000 MW while midterm forecasts indicated peak loads as high as 47,000 MW for Feb. 16.

SPP's day-ahead load forecasts projected higher load levels than were observed in real time for much of the week of Feb. 15. A few factors may have contributed to this over-forecasting of system load, including:

- President's Day holiday Monday, Feb. 15.
- Public appeals and load management.
- Commercial customer reductions following system load-shed events.
- Winter weather including snow and ice caused abnormal load behavior due to school and work closures.

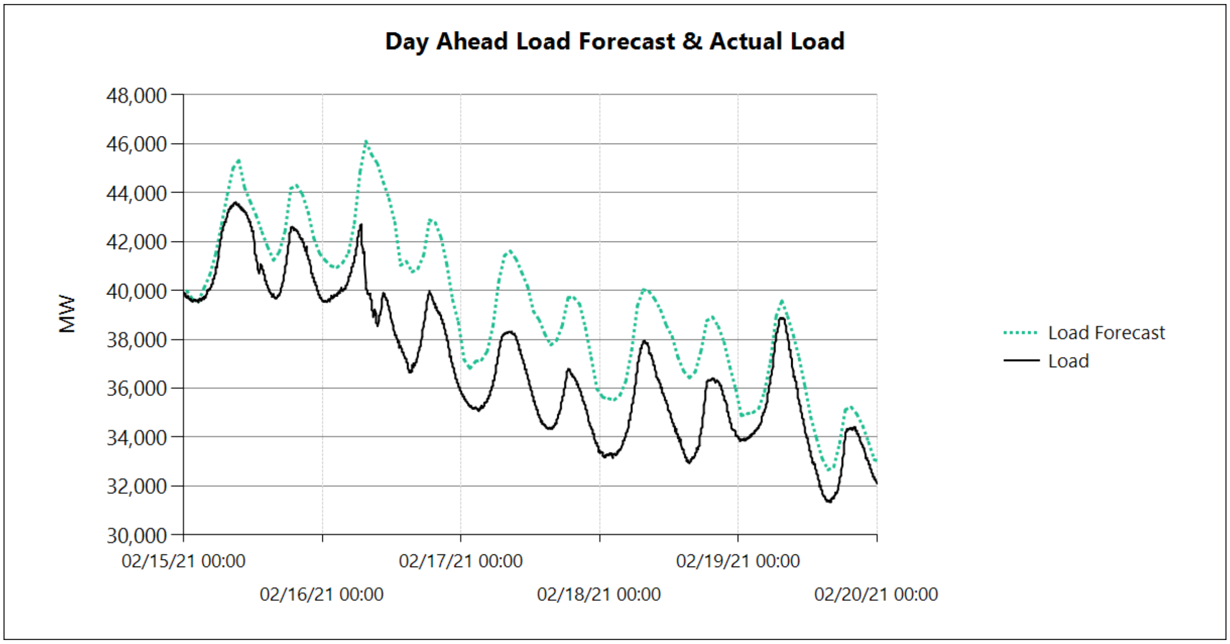

Figure 8: Day-ahead load forecast and actual load

WIND FORECASTING

Figure 9 shows the performance of the day-ahead wind forecast during the week of Feb. 15. The deviation observed late Feb. 15 through the morning of Feb. 17 was in part due to curtailments associated with system congestion.

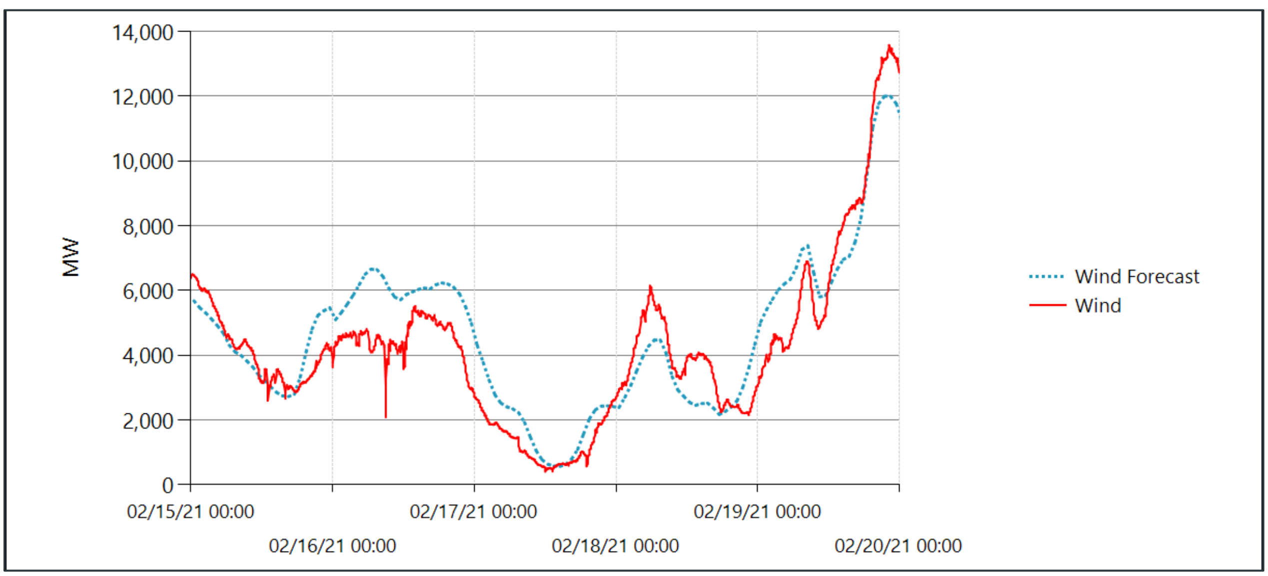

Figure 9: Day-ahead wind forecast and actual wind

MONDAY, FEB. 15: IN-DEPTH REVIEW

On Feb. 15, available capacity became insufficient to meet system demand. At 12:04 p.m., SPP directed 610 MW of load shed. Figure 10 shows online available generation combined with net scheduled interchange, load and Area Control Error (ACE). ACE is the instantaneous difference between a BA's scheduled and net actual interchange, taking into account the effects of frequency bias and correction for meter error. Near the time of load shed, when available generation fell below load, SPP experienced negative ACE indicating that the SPP BA was deficient and relying on unscheduled imports from the Eastern Interconnection to serve load. The morning outage and fail-to-start total of 3,790 MW at 10 a.m. represents capacity on resources that were in the current operating plan (COP) but failed to meet their commitment.

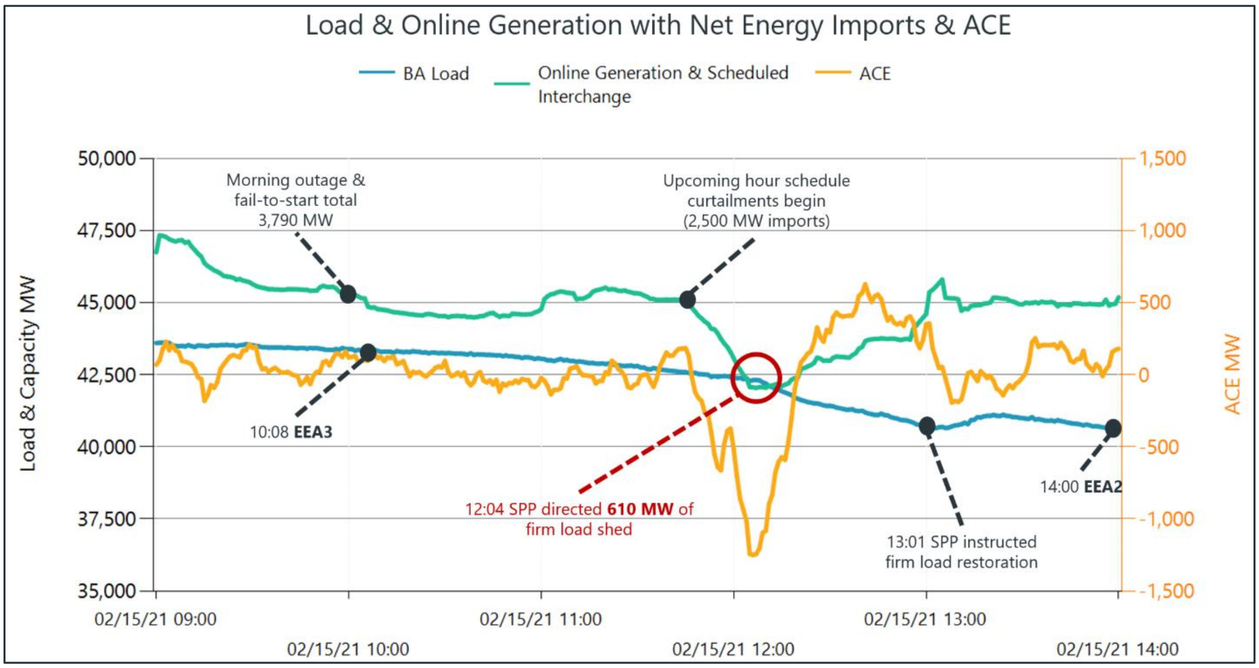

Figure 10: Load & Capacity with Area Control Error (ACE) (Feb. 15, 2021)

At the time of load shed, the real-time balancing market (RTBM) was completely deficient of reserves and dispatchable headroom. Capacity was present on resources that were manually reduced by out-of-merit-energy (OOME) instructions. This capacity was not deliverable due to transmission constraints and could not be utilized to serve load. Figure 11 shows the general areas of online capacity near the time of load shed Feb. 15. For this snapshot, a total of 648 MW of capacity was manually reduced. The red arrow indicates the region and direction of flow of the constraint that drove the manual reductions.

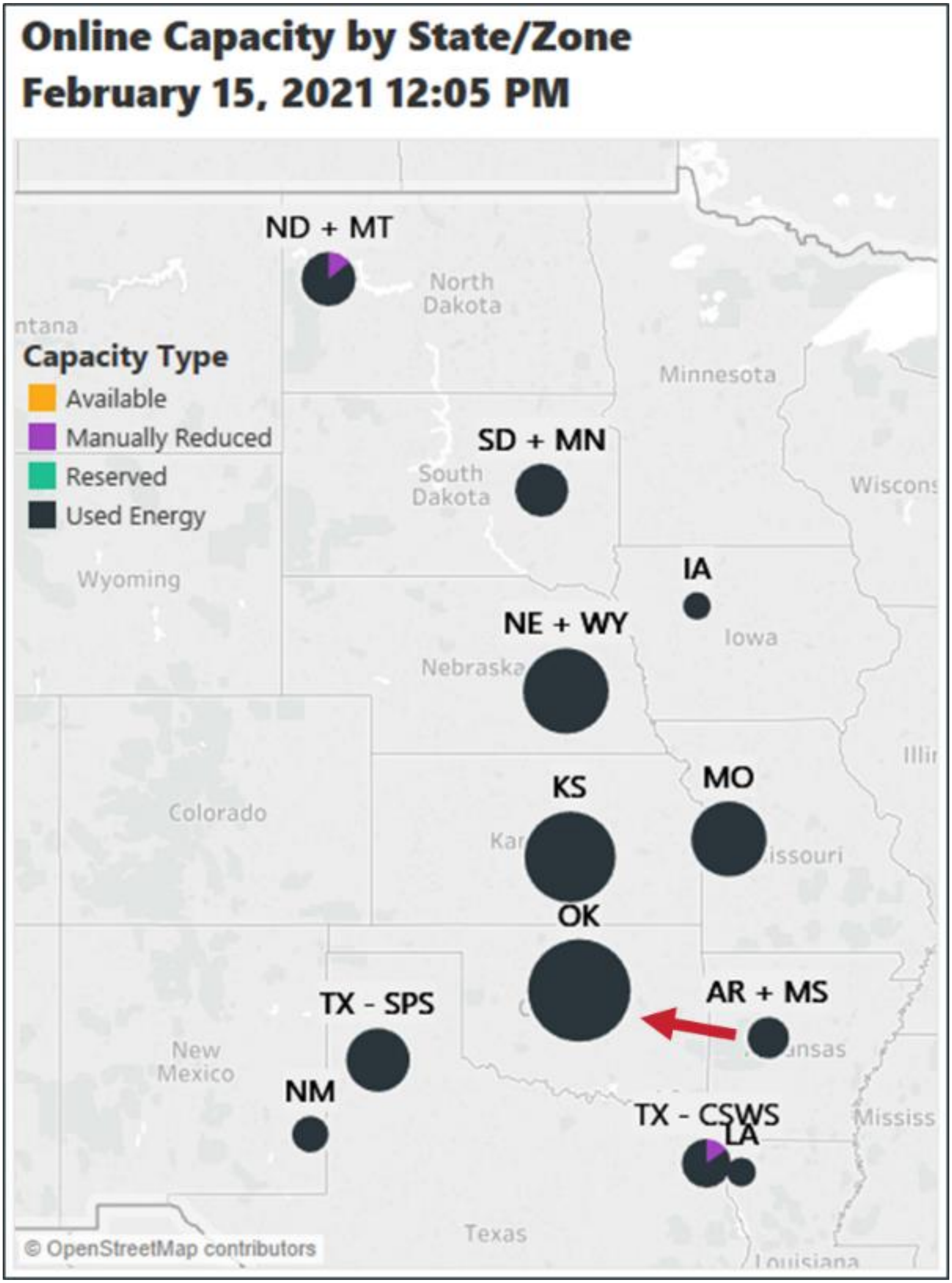

Figure 11: Map of online capacity (Feb. 15, 2021)

TUESDAY, FEB. 16: IN-DEPTH REVIEW

On Feb. 16, SPP directed a total of 2,718 MW of load shed: 1,359 MW at 6:44 a.m. and an additional 1,359 MW at 7:17 a.m. SPP also initiated the curtailment of up to 287 MW of firm exports as a share of SPP firm load obligation interruption. SPP sent its first instructions to partially restore load at 9:32 a.m., and sent subsequent instructions to restore the remainder of load at 10:07 a.m., effectively indicating that all load effected by the load-shed instructions could be returned to service. Figure 12 illustrates load and online generation with net energy imports and ACE during the morning of Feb. 16.

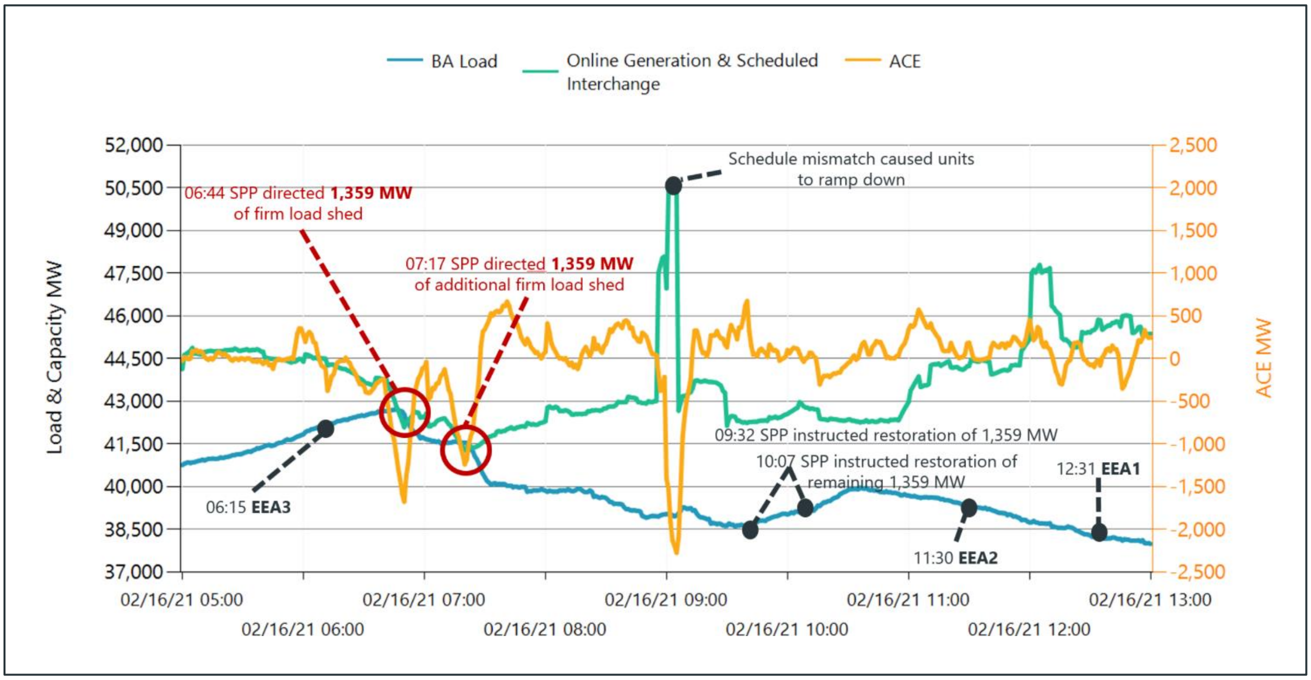

Figure 12: Load & Capacity with ACE (Feb. 16, 2021)

Near the time SPP issued load-shed instructions, the RTBM was unable to clear dispatchable headroom and was clearing only a small amount of reserves. As on Feb. 15, there was undeliverable capacity present on resources that were manually reduced. Figure 13 shows the general areas of online capacity near the time of load shed Feb. 16.

For this snapshot, a total of 1,862 MW was the manually reduced. Manual reductions were in place on several different resources to mitigate loading on various constraints across the SPP region. The red arrows indicate the locations and directions of flow for a few of the main constraints limiting generation.

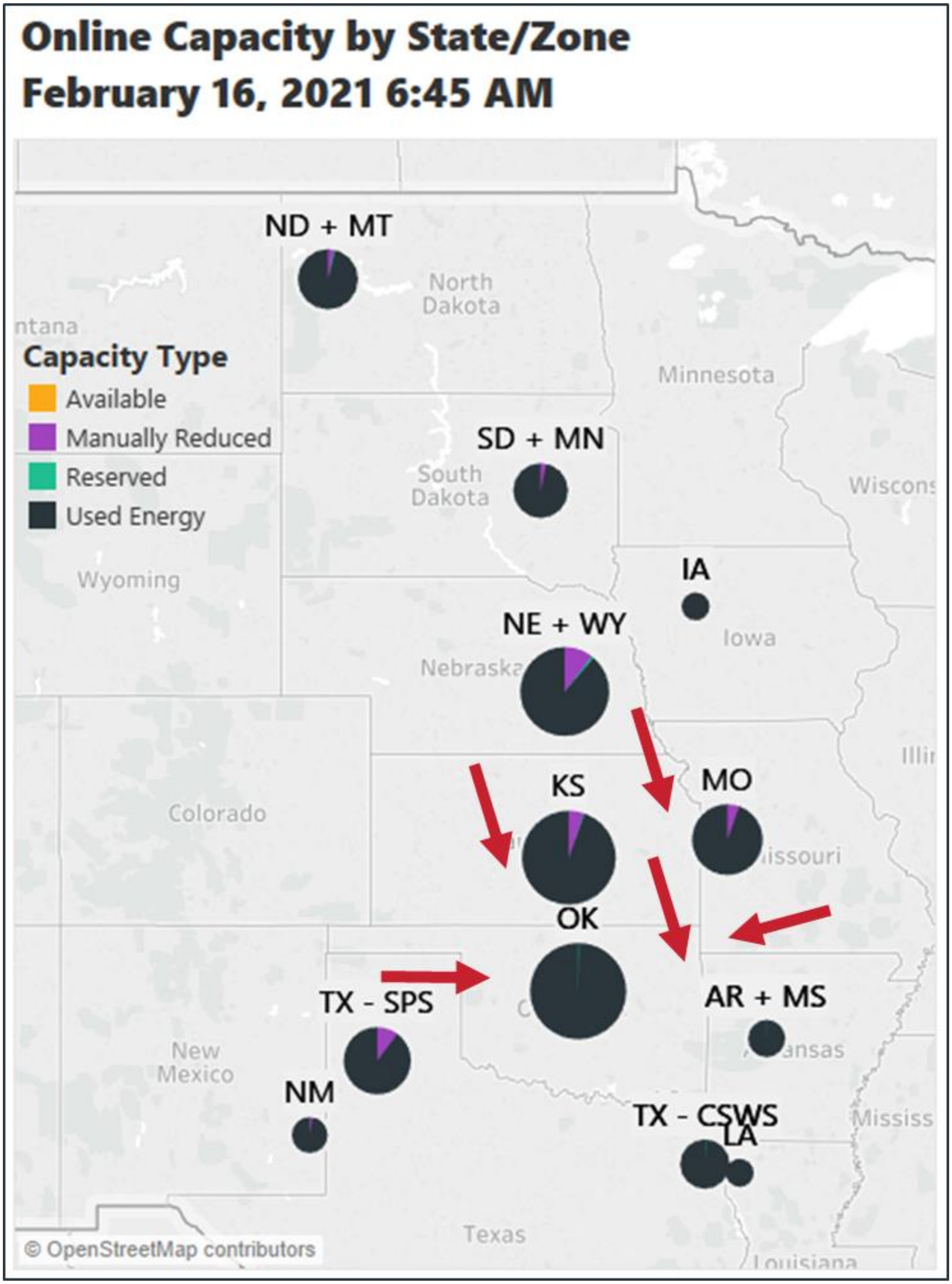

Figure 13: Online capacity map (Feb. 16, 2021)

WEDNESDAY, FEB. 17-FRIDAY, FEB. 19: OVERVIEW OF OPERATIONS

Although the worst of the event had passed, SPP continued to experience moments during Feb. 17-19 where its energy supply encroached on its ability to meet load and reserve requirements, requiring the declaration of heightened levels of Energy Emergency Alerts. Figure 14 shows generation with scheduled interchange and load, as well as load with contingency reserves.

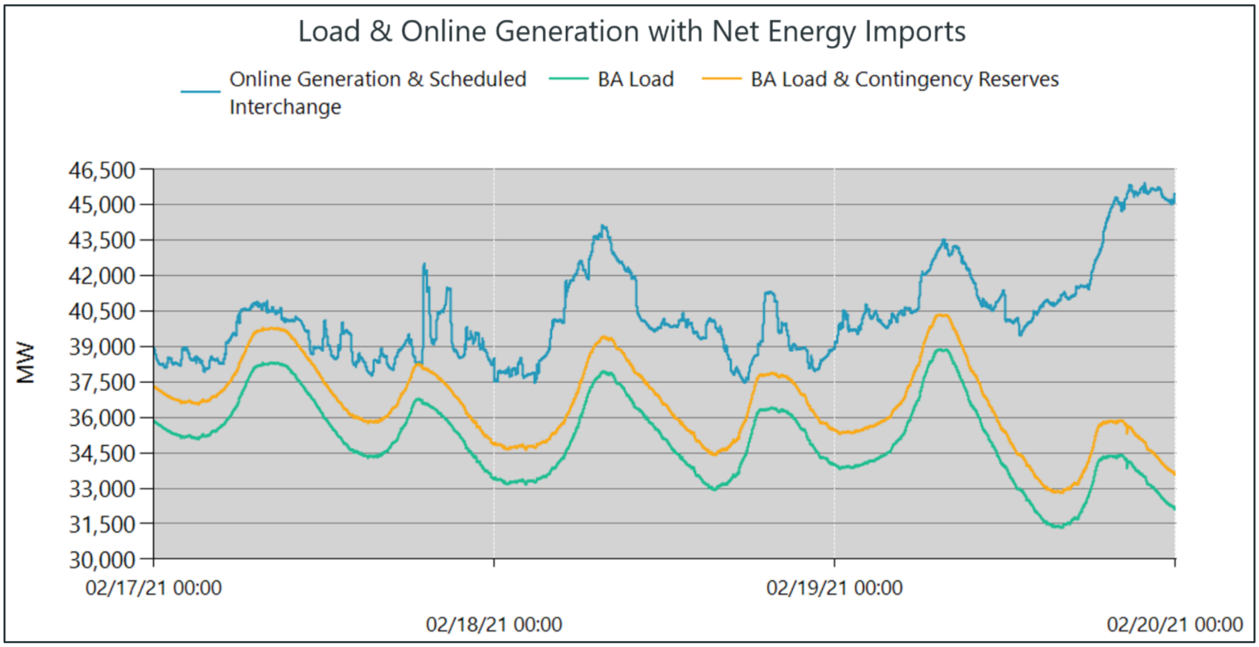

Figure 14: Load, Capacity and Load with Contingency Reserves (Feb. 17-19, 2021)

ANALYSIS OF OPERATIONAL AND MARKET PERFORMANCE

GENERATION AVAILABILITY AND FUEL ASSURANCE

During the 2021 winter weather event, all resource types experienced challenges ranging from operational reductions to total resource outages resultant from either frozen equipment or interrupted fuel supplies.

GENERATION ASSESSMENT PROCESS

SPP utilizes its Generation Assessment Process (GAP) to help ensure the SPP Balancing Authority's obligations can be met and to identify timeframes of allowable maintenance margin. The GAP methodology was reviewed and endorsed by the Operating Reliability Working Group. GAP is executed three times daily and results are posted publicly to ensure the most accurate information is available to generator owners/operators looking to schedule outages. SPP uses this information as part of its outage pre-approval process.

GAP creates a data set of actual historical values from the previous three years for all intervals plus and minus 15 days from the operating day. Maintenance margin calculation considerations include: total installed generation capacity (excluding variable energy resources), historical forced generation outages, current scheduled generation outages, historical wind performance, historical load and historical operating reserves.

CAPACITY AVAILABILITY

Based on historical averages over the past five years, SPP's market typically has about 55 gigawatts (GW) of available generation capacity[16] in February. As illustrated in Figure 15, that capacity dipped to roughly 35 GW during the week of Feb. 14, 2021. This 20 GW reduction from typical available capacity was primarily due to higher than usual fuel-supply deficiencies, wind-turbine freezing, and other challenges associated with operating equipment in extremely cold conditions such as frozen cooling towers, intakes, fuel lines, transmitters, etc. On Feb. 15 and 16, roughly 50% of forced generation outages cited fuel-supply issues as their cause.

[16] Includes reported available capacity of nonvariable resources and forecasted available energy from variable resources.

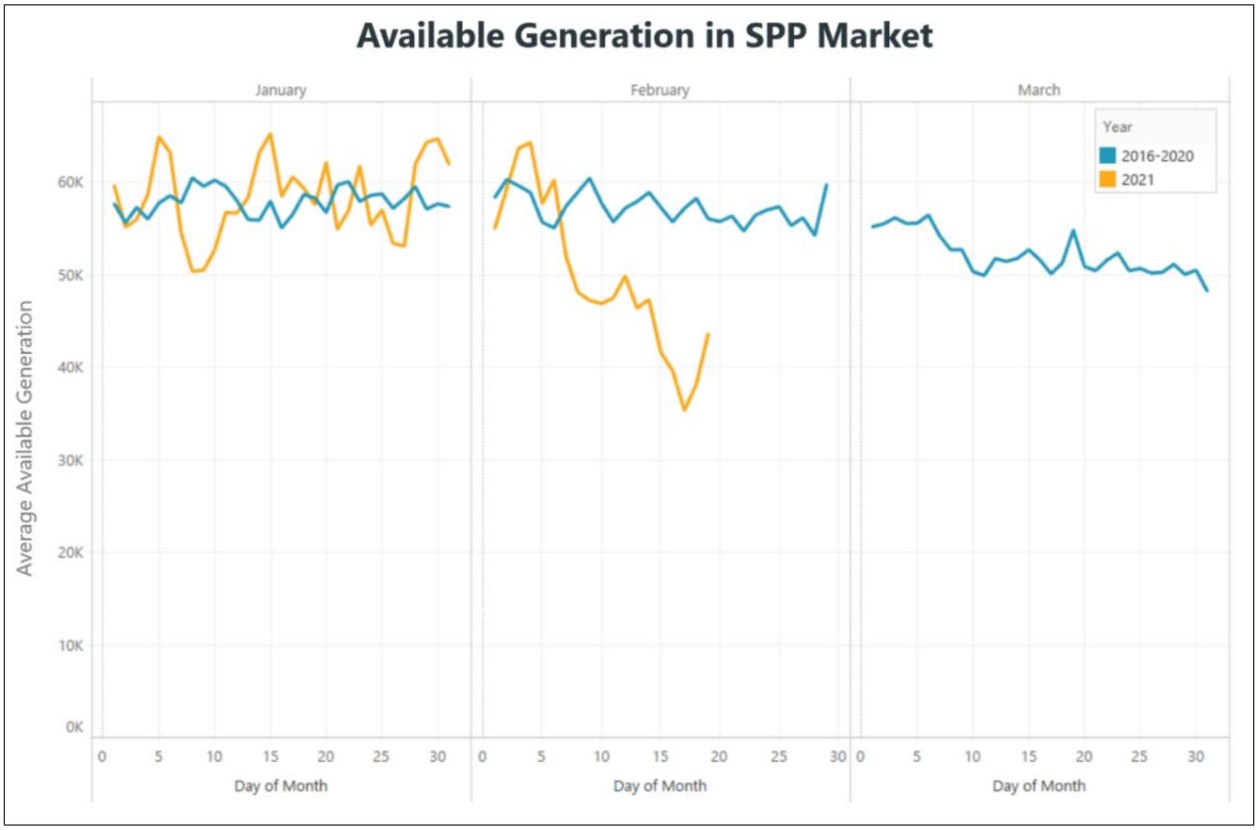

Figure 15: Available Generation in the SPP Market

FORCED OUTAGES

Figure 16 shows the forced generation outages in effect by fuel type during the two weeks preceding and the week of the event.

On Feb. 7, freezing rain and freezing fog moved into the central and southern regions of SPP (Kansas, Oklahoma and the Texas panhandle) and reduced available wind capacity due to ice buildup on turbine blades. Natural gas supply was limited due to extremely cold temperatures across the central U.S. [17]

SPP observed up to approximately 33 GW of forced outages during the week of the event, with an average of 30.5 GW of forced outages Feb. 16. Natural gas generation experienced an average of nearly 18 GW of forced outages during Feb. 16, and of those outages, nearly 75% cited lack of fuel supply as the cause.

[17] Members and market participants submitted CROW tickets indicating icing issues on wind resources and fuel supply concerns for natural gas generators.

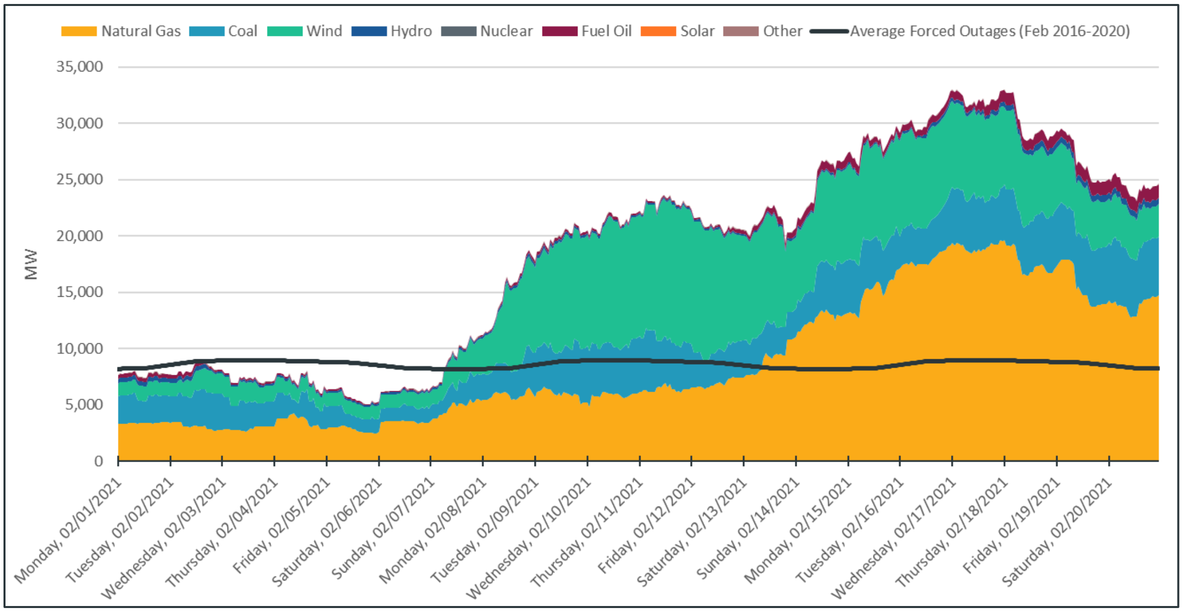

Figure 16: Forced generation outages as submitted in CROW by Fuel Type

Figure 17 shows the total generation unavailable due to forced outages, distinguished by the cause for the outage[18] as submitted into SPP's outage scheduling tool, Control Room Operations Window (CROW). On average, over 48% of all forced outages experienced during the week of the event were caused by fuel supply issues.

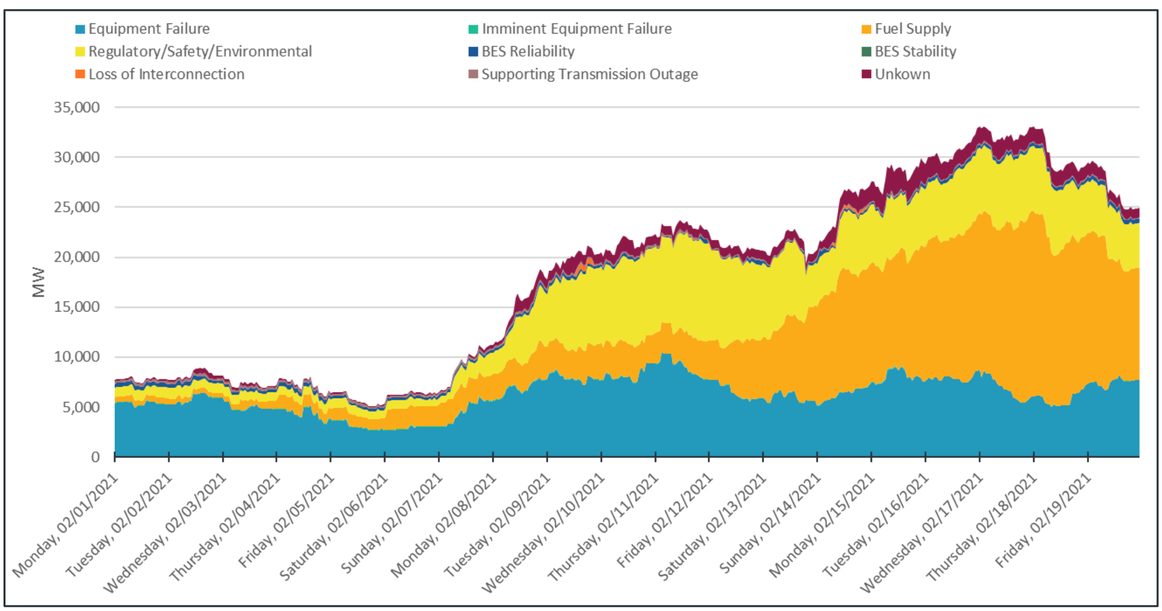

Figure 17: Forced generation outages as submitted in CROW by Cause Code

[18] Outages citing the regulatory/safety/environmental cause code consist largely of wind turbine outages due to cold weather and icing.

GAS SUPPLY

Figure 18, Figure 19 and Figure 20 illustrate natural gas, wind and coal generation that were unavailable Feb. 1-20 due to forced outages, distinguished by the associated cause as submitted in CROW. On average, approximately 72% of all forced gas generation outages experienced during the week of the event were caused by fuel-supply issues.

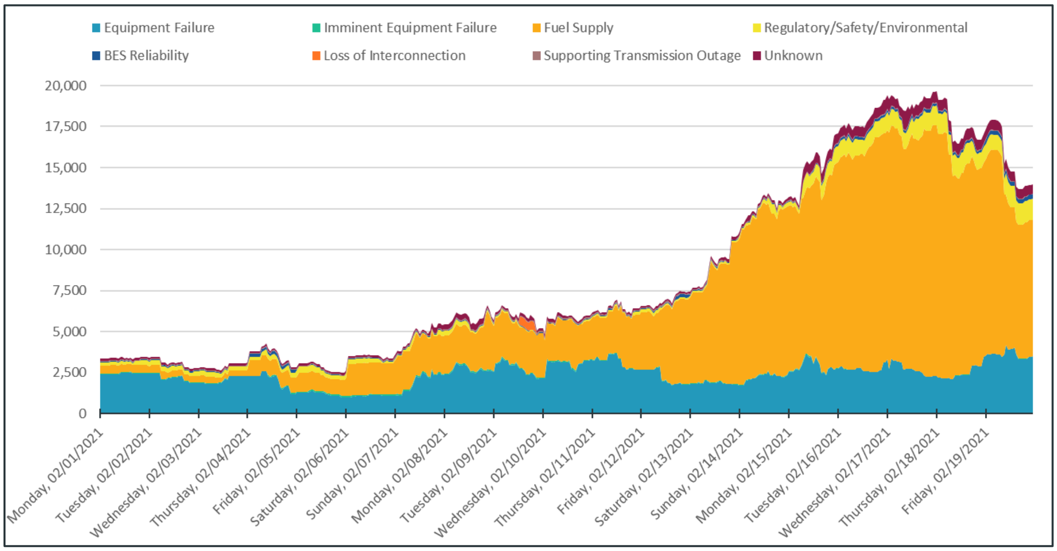

Figure 18: Forced natural gas generation outages as submitted in CROW by Cause Code

On average, approximately 51% of all forced wind generation outages experienced during the week of the event were caused by regulatory/safety/environmental issues, with 90% of those related to icing conditions.

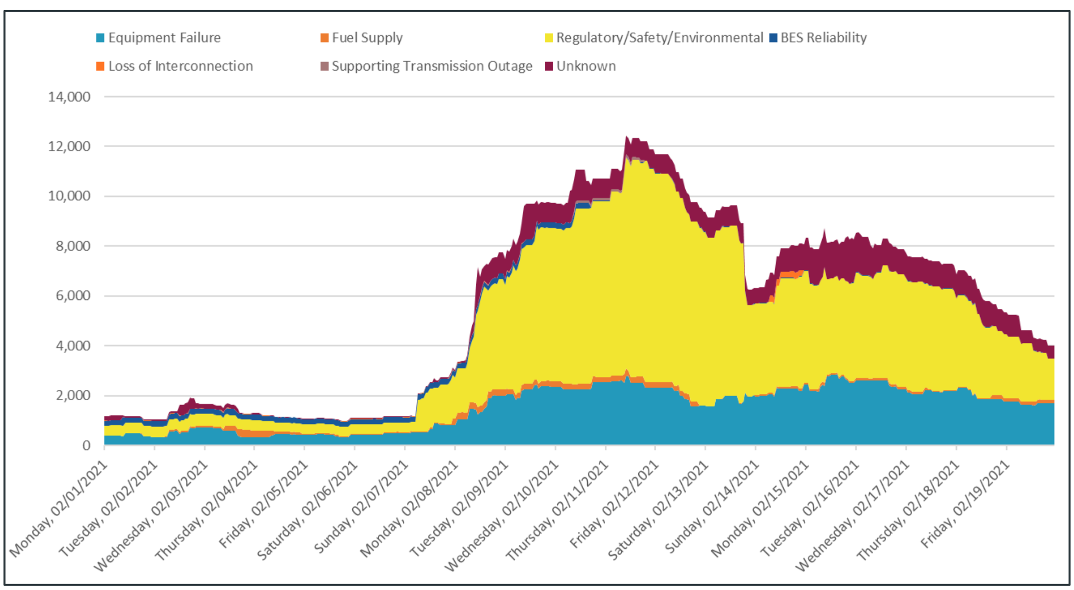

Figure 19: Forced wind generation outages as submitted in CROW, by Cause Code

On average, approximately 43% of all forced coal generation outages experienced during the week of the event were caused by equipment failure with another 28% caused by fuel-supply issues.

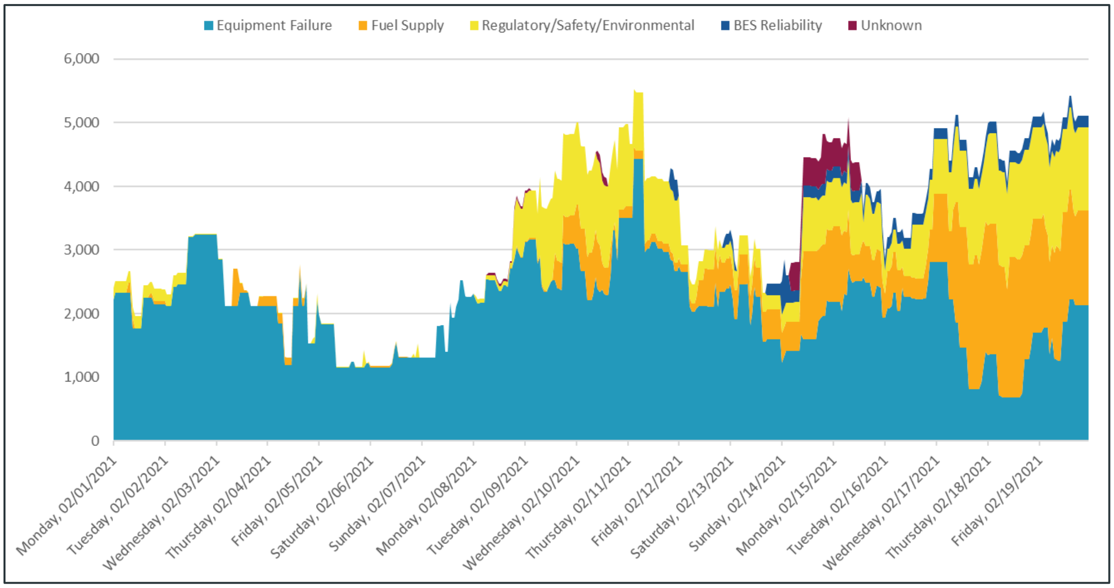

Figure 20: Forced coal generation outages as submitted in CROW, by Cause Code

GRID-SWITCHABLE RESOURCES

During the winter event, SPP coordinated with ERCOT regarding the use of grid-switchable resources that can operate in either SPP or in ERCOT. Three such resources are considered accredited capacity in SPP. These resources were committed and used as available to supply SPP load during the event when necessary to prevent service interruptions Feb. 15 and Feb. 16. SPP allowed the resources to supply load in ERCOT during times when they were not needed in SPP.

MUNICIPAL GENERATION, DEMAND RESPONSE AND BEHIND-THE-METER AVAILABILITY

There were municipal generators not directly connected to the SPP transmission system that were capable of operating but did not run during the event. SPP, as the BA, does not have a complete picture of all resources that may be available to assist during an energy emergency, and as a result some resources did not assist where needed. SPP did issue appeals to members to identify any resources not in the market that could assist with supplying load, but some were still not notified to come on-line.

CONCLUSIONS REGARDING FUEL ASSURANCE

The generating resources most impacted by the 2021 winter weather event were those fueled by natural gas.

Similar to electric power, the available natural gas fuel for consumption by electric generation and other customers is limited by the capacity of the supplies and transportation provided by the gas pipeline system. Extreme cold weather experienced across the SPP region resulted in natural gas procurement and deliverability issues. Increased demand for natural gas to heat homes combined with production issues attributed to wellhead freeze-offs resulted in a lack of access to natural gas by generator operators.

Upon review of information provided by the SPP Market Monitoring Unit (MMU), it is clear that extremely high natural gas prices were the primary driver of record high energy offers that exceeded the Federal Energy Regulatory Commission (FERC)-required offer cap of $1,000/megawatt-hour (MWh) for the first time in SPP's market history. On Feb. 15, SPP's market price reached an all-time high of $4,274.96/MWh in the day-ahead market (DAMKT). By comparison, the average price of energy in SPP's DAMKT for the entire year of 2020 was $17.69/MWh. Natural gas markets are not subject to price or offer caps, while electricity markets like SPP's are.

It is important to note that the electric industry does not have the ability, nor should it have the responsibility, to ensure a reliable, resilient and affordable natural gas supply. It is incumbent upon the natural gas industry to make the changes necessary to improve the supply of natural gas during extreme weather events. It is imperative that regulators understand the limitations of the electric industry in improving natural gas supply. Any new requirements to improve natural gas supply need to be imposed upon the gas industry and not the electric industry if this situation is to be improved.

The lack of access to natural gas was the largest contributing factor to the severity of the event, and establishes the need for better coordination and communication between the gas and electric industries moving forward.

In particular, additional early communication of potential severe conditions and the forecasted high demand for natural gas could have provided both industries with useful preparation time.

SPP has made several improvements related to gas-electric coordination in the past five years. In 2015, FERC issued Order No. 809 "Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities." In response to the order, in October 2016, SPP shortened the DAMKT timeline by 30 minutes and shifted the closing and posting times earlier in the day. In May 2020, SPP further reduced the DAMKT timeline by an hour. In addition, between 2016 and 2018, SPP coordinated with market participants to increase awareness of the need for additional detail in outage reporting, particularly fuel issues. SPP also recently implemented a multiday commitment and pricing forecast, which should provide generation-owning market participants with additional information related to generation needs. SPP

continues to seek opportunities for gaining efficiencies that better align the DAMKT with the gas day.

While SPP has focused on communication between the RTO and the market participant, SPP believes there should be a focus on increased communication between the RTO and the gas industry, i.e., communicating the need for gas and any deliverability issues of gas. SPP also believes it is important to understand the impacts of the development of natural gas fueled resources on the gas industry. SPP also thinks it is imperative to coordinate new projects with the gas industry, with the goal being to either increase the RTO knowledge of gas resource availability or increase the availability of gas to those same resources.

Certain system conditions may result in severe impacts to the electric or gas infrastructure. Better coordination is needed between the electric and gas industries to identify potential infrastructure contingencies within the RTO that could have a large impact on gas generators within the SPP region. The SPP Balancing Authority (BA) Emergency Operating Plan (EOP) does not presently include procedures for assessing and analyzing gas infrastructure reliability impacts on the SPP region during severe weather events, capacity emergency procedures, significant pipeline maintenance outages, pipeline operational flow orders, or during any other applicable conservative operations event.

FUEL ASSURANCE RECOMMENDATIONS

Table 11: Summary of recommendations to the board related to fuel assurance

#	TIER	CATEGORY	RECOMMENDATION
FA 1	1	Policy	Develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region.
FA 2	1	Assessment	Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events.
FA 3	2	Policy	Develop policies to improve gas-electric coordination that better inform and enable improved emergency response.

RESOURCE ADEQUACY, PLANNING AND AVAILABILITY

Figure 21 illustrates generation capacity in SPP. Nameplate capacity reflects the maximum amount of energy that all generation in SPP can produce based on equipment ratings.

Accredited capacity is the amount of generation capability owned or purchased by entities in SPP responsible for serving load that is expected to be available to meet peak demand. Energy production reflects how much energy was actually produced by generating assets in SPP during the most recent year.

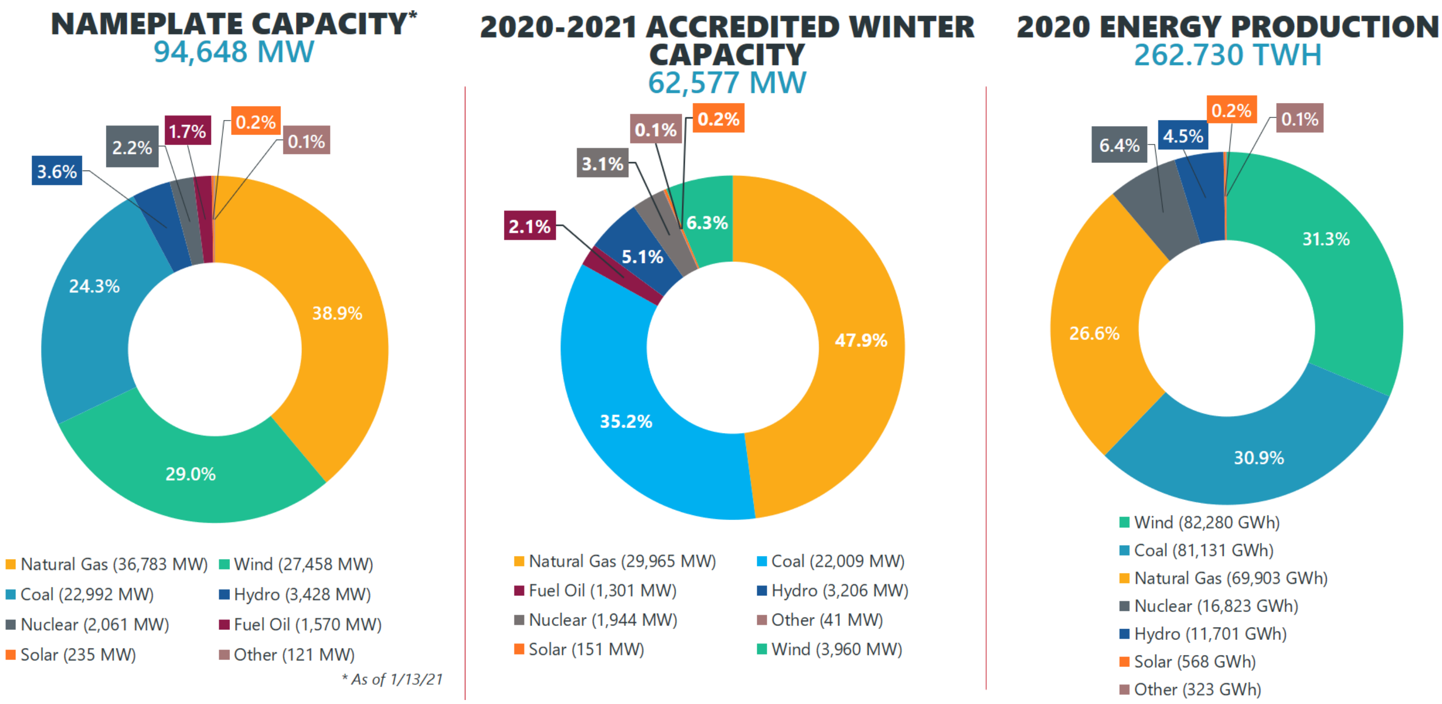

Figure 21: SPP generating capacity overview

During the periods on Feb. 15 and 16 when SPP declared an EEA 3, approximately 42% of nameplate capacity was available on average. The total amount of generation available during these time frames constituted approximately 65% of SPP's accredited capacity, with 87-88% of that available generation provided by accredited resources.[19]

[19] Each year, SPP verifies the specific amounts of each generating resource owned by load-responsible entities in SPP that are accredited for capacity purposes. During the event, generation available to SPP consisted of both accredited capacity resources and those that are not accredited. For these numbers, available generation represents the total economic maximum capability of online generation resources.

Figure 22 shows the status of generation capacity in SPP, distinguishing capacity that was on outage, unavailable and available. It also shows the used energy.

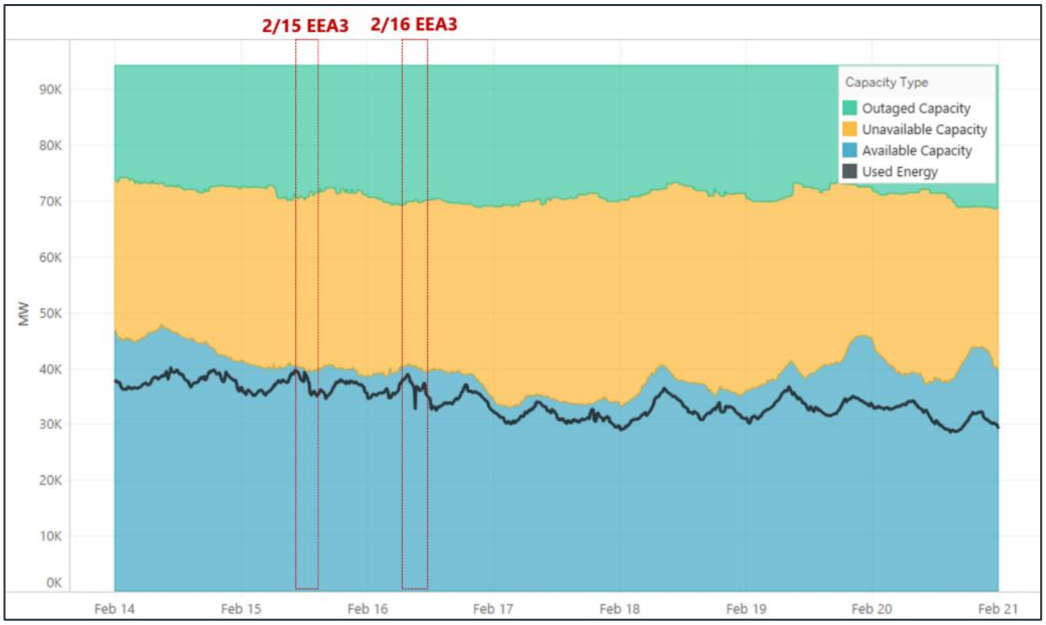

Figure 22: Total generating capacity in SPP

Considering only wind generation, 12-16% of nameplate capacity was available on average during the EEA3 events. The total amount of wind energy produced on average during these time frames constituted approximately 79-101% of accredited wind capacity, with 43-54% of that energy provided by accredited resources. This is illustrated below in Figure 23.

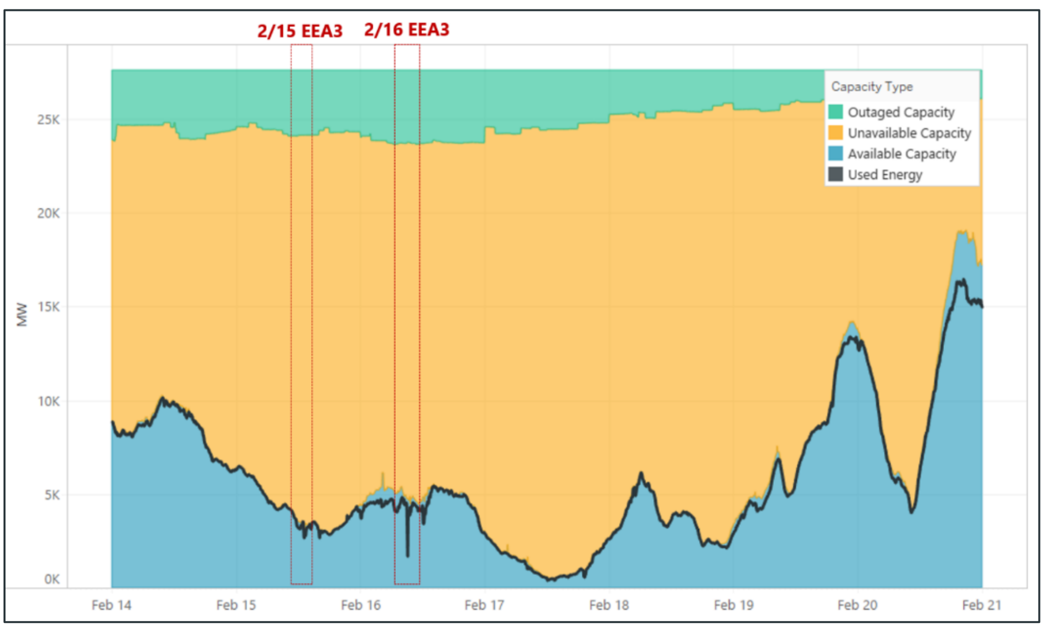

Figure 23: Total wind generating capacity in SPP

Regarding coal generation, about 77-79% of nameplate capacity was available on average during the EEA3 events. The total amount of coal energy produced on average during these time frames constituted approximately 87-89% of accredited coal capacity, with 98% of that energy provided by accredited resources. This is illustrated below in Figure 24.

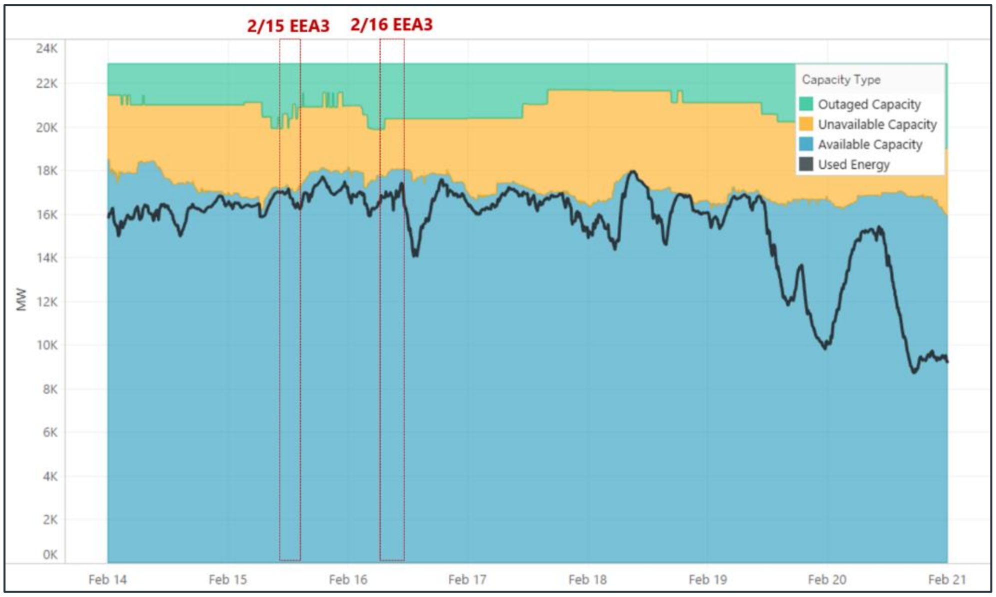

Figure 24: Total coal generating capacity in SPP

Regarding gas generation, about 34-37% of nameplate capacity was available on average during the EEA3 events. The total amount of gas energy produced on average during these time frames constituted approximately 40-45% of accredited gas capacity, with 95% of that energy provided by accredited resources. This is illustrated below in Figure 25.

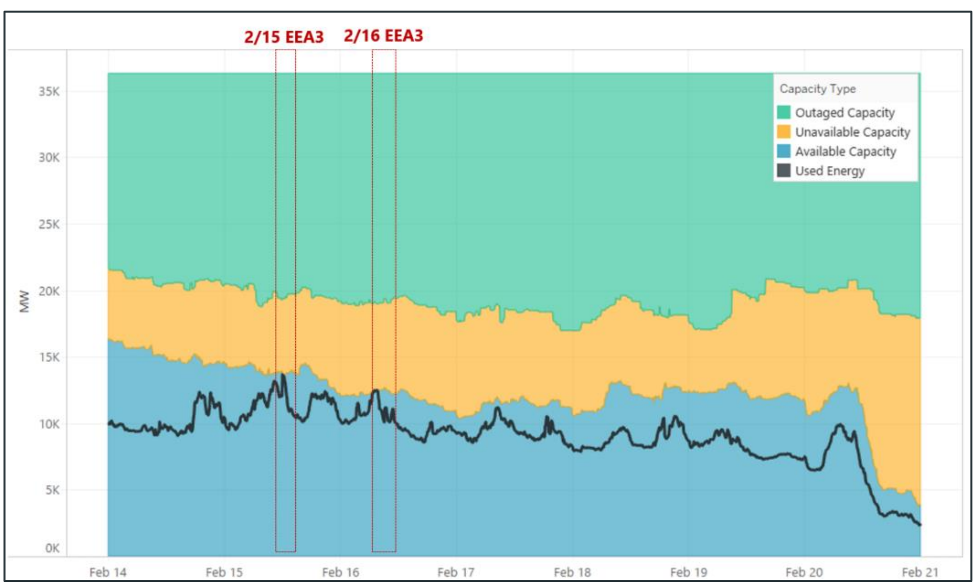

Figure 25: Total gas generating capacity in SPP

The following graphs compare available generating capacity with historical accredited capacity in February. The historical data set includes available generating capacity from each February of years 2014 through 2020. The shaded background indicates the total accredited amount of capacity that was applicable during February 2021.

The accredited value applicable to the 2020-2021 winter season is 62,577 MW for resources registered in the SPP market. The total accredited capacity used to meet resource adequacy requirements was 65,174 MW, which includes behind-the-meter generation not registered in the SPP market and firm imports to the SPP BA.

In the following graphs, available generating capacity for wind and solar is equivalent to the real-time dispatch amounts, while the generating capacity for all other fuel types relies on the real-time economic maximum limits for units that were not on outage. The economic maximum limit is the uppermost limit set in the resource market offer for which a resource can operate to without moving into emergency ranges.

Accredited capacity amounts used in these graphs are based on market resources only.

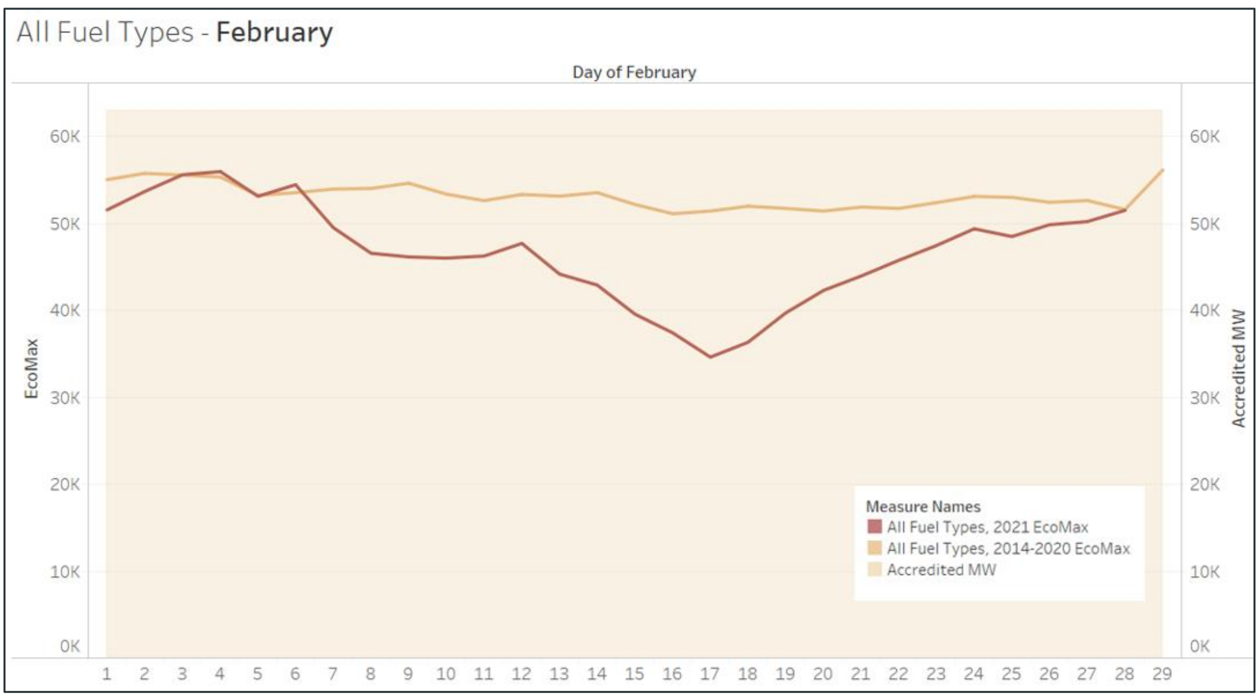

Figure 26: February 2021 available capacity as compared to prior year average

Wind availability was variable during February 2021. A significant icing event began Feb. 7, which contributed to the sharp decline in availability, as shown in Figure 27 below. Available capacity for wind is set to the real-time market dispatch of wind resources.

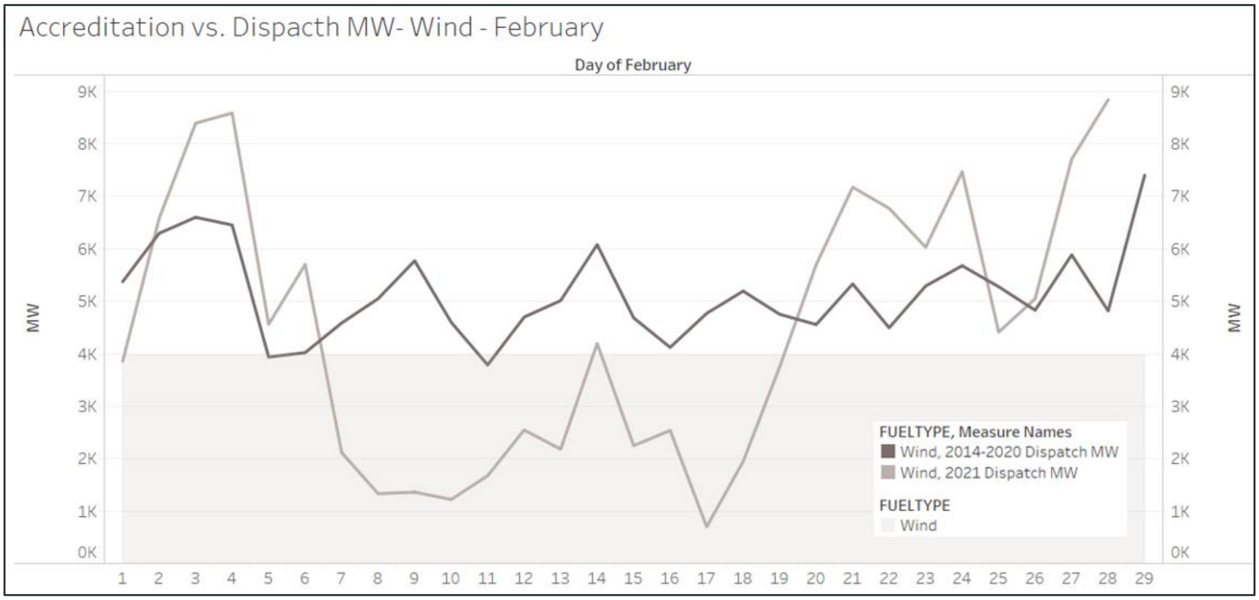

Figure 27: February 2021 available wind capacity as compared to prior year average

Coal availability for February 2021 fell roughly 2 GW below prior years. Available capacity for coal, shown in Figure 28, is based on the real-time economic maximum for units not on outage.

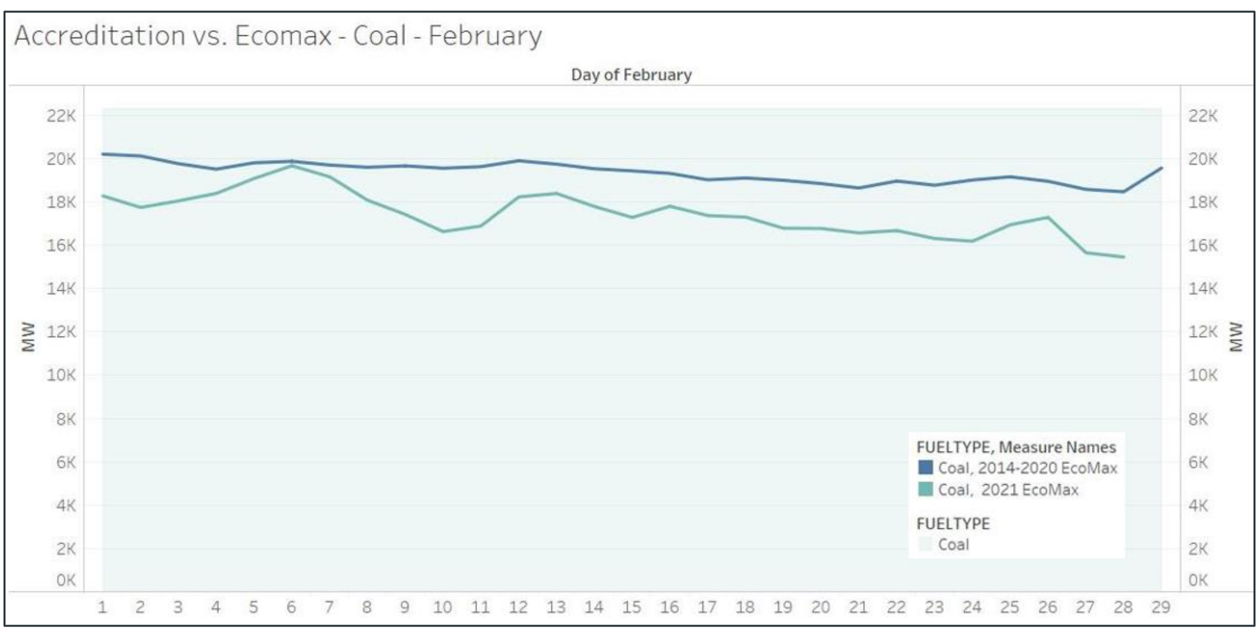

Figure 28: February 2021 available coal capacity as compared to prior year average

Gas generation availability dipped substantially during the week of Feb. 14. In Figure 29, available gas capacity is set to the real-time economic maximum for units not on outage.

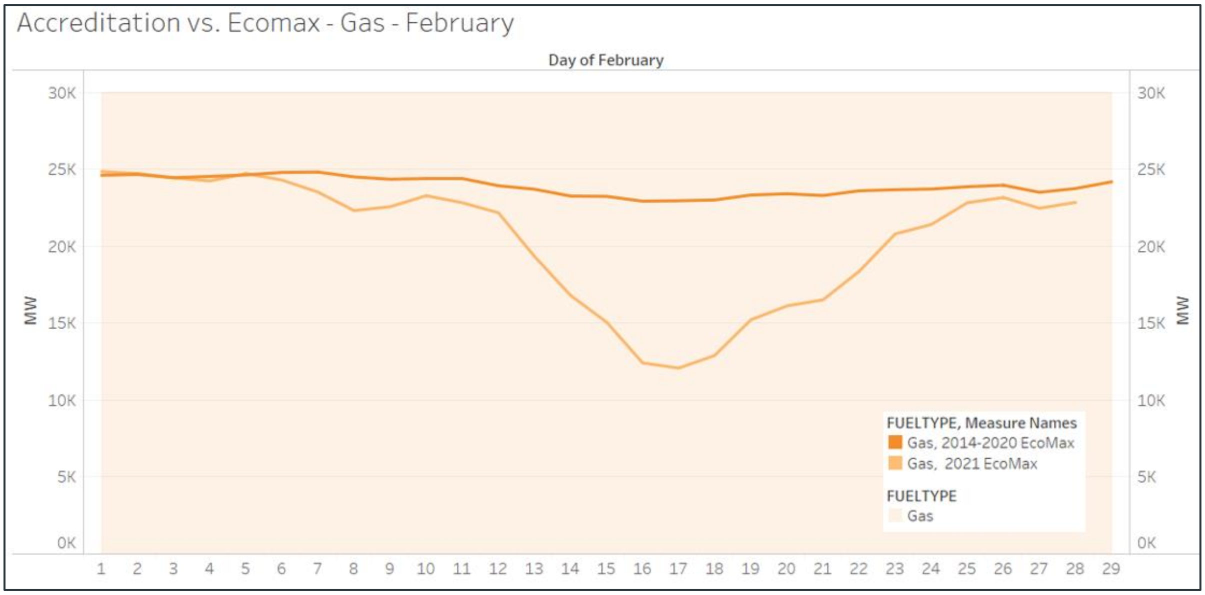

Figure 29: February 2021 available gas capacity as compared to prior year average

CONCLUSIONS REGARDING RESOURCE PLANNING AND AVAILABILITY

The 2021 winter weather event highlighted weaknesses of the components of the supply-side of the grid.

All forms of generation were stressed, and there were outages across all generation types. The event struck during a time of change in the way energy and capacity are supplied in the region. The event highlighted the need to further assess SPP's ability to reliably operate the system with the increased use of intermittent resources and further reduction of base-load resources. As the resource mix has changed and is expected to continue to evolve, the way resource adequacy has been determined in the past does not appear adequate to meet the needs of the future.

Accreditation values and capacity requirements based on summer assumptions do not adequately portray the amount of capacity that can be relied upon and needed during other critical seasons.

Summer peak assessments cannot accurately determine the needs of a severe event in the winter. Fuel supplies are under different constraints, wind and solar patterns are different, and the ability of a generator to start can vary markedly. Because of this, SPP needs to have a better understanding of the strengths and weaknesses of all resource types during times other than summer. SPP should also assess the importance of diversity in supply and demand resources

and how these resource types interact with each other during periods of stress and assess cost effective ways to ensure that reliability is able to be maintained. The 2021 winter weather event underlined the importance of this work.

Historically, data has shown the average economic max capacity for conventional resources in SPP's Integrated Marketplace is lower than the accredited capacity submitted for resource adequacy purposes. SPP and the SAWG have diligently worked over the past two years to begin implementing more robust and reliable accreditation methodologies across all resource types. This effort started with the implementation of the effective load carrying capability (ELCC) methodology for wind, solar and battery storage starting with the 2023 summer season.

Additionally, there is an effort underway to evaluate a form of performance-based accreditation for conventional resources. This important work should continue with extra emphasis and with focus on seasonal expectations.

Currently, SPP resource adequacy policies place an obligation on each load-responsible entity (LRE) to meet its individual winter season noncoincident demand plus the planning reserve margin (PRM) requirement. The winter season PRM is based on a Loss-of-Load Expectation (LOLE) study that is performed every two years and determines the appropriate amount of capacity needed to reliably maintain the one-day-in-10-year standard.

While this study encompasses the whole year, its focus is on the summer peak season, for which the majority of loss of load in the SPP region is analyzed to occur during the summer timeframe. Therefore, the PRM applied to the winter season is based on the summer season demand values. Expectations of abnormally excessive generation outages during extreme weather events (cold, heat, drought, flooding, atmospheric conditions) are not currently included in the planning study with a higher than previously experienced occurrence rate.

Currently, LREs that schedule planned outages during the summer season are not allowed to count that capacity toward their resource adequacy requirement. As risk of loss of load is seen to expand beyond the summer season into the winter season and potentially into the shoulder months, policies need to address how accredited capacity may be counted in the summer and winter seasons with planned outages taken into account.

RESOURCE PLANNING AND AVAILABILITY RECOMMENDATIONS

Table 12: Summary of recommendations to the board related to resource planning and availability

#	TIER	CATEGORY	RECOMMENDATION
RPA 1	1	Assessment	Perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix.
RPA 2	1	Policy	Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives, that ensure sufficient resources will be available during normal and extreme conditions.

EMERGENCY RESPONSE PROCESSES AND PLANNING

SPP's emergency response processes are detailed in the SPP BA Emergency Operating Plan (EOP)[20]. This plan includes procedures for issuance of load-shed instructions. Load shed is a controlled interruption of electric service to end-use customers under an EEA level 3 when all other means of supplying internal load have been exhausted, or to maintain area control error (ACE) so as to not jeopardize the reliability of the bulk electric system. Per the SPP Operating Criteria and Appendices[21], the Reliability Communications (R-Comm) tool is the primary means of communication for responsible entities to receive, acknowledge and carry out load-shed instructions issued by the SPP BA.

SPP staff performs load-shed tests regularly. SPP also conducts annual training for SPP operators on energy emergency alerts and load shed for the SPP BA, including the use of the R-Comm tool.

Each member transmission operator (TOP) is responsible for developing, maintaining and testing its own emergency response plan and for carrying out load-shed instructions pursuant to those plans.

LOAD SHED DURING SYSTEM CONGESTION

During load shed on Tuesday, Feb. 16, 2021, there were locations where generation was curtailed at the same time load was being shed on the same side of constraints. Considering that load shed can be considered a very expensive demand response unit, it may not be optimal to dispatch a high-cost unit up at the same time a lower-cost unit is being dispatched down in the same area. Pro-rata curtailments are reasonable when there is no congestion on the system but could lead to excessive load shedding during times when there is congestion on the system.

DISTINGUISHING BETWEEN FIRM AND NONFIRM EXPORTS

SPP did not distinguish between exports that were firm (associated with a capacity or firm energy transaction) versus nonfirm energy during the EEA. The North American Electric Reliability Corporation (NERC) Reliability Standard EOP-011-1 Attachment 1 identifies that during an EEA level 1, "Nonfirm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed." During the event, SPP treated exports pursuant to their transmission service priority only without regard to the firmness of the energy that was associated with the transaction. SPP needs procedures and processes that clearly identify that curtailment is based upon the transmission service level for transmission curtailments and based upon the level of firmness of the energy for EEAs.

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[20] Revision 7.5 (Effective 09/30/2020), https://www.spp.org/spp-documents-filings/?id=34055
[21] Revision 2.2 (Effective 06/17/2019), https://www.spp.org/documents/60100/spp%20operating%20criteria%20and%20appendices%20v2.2.pdf

EMBEDDED ENTITIES AND LOAD-SHED PROCEDURES

SPP did not have an accurate representation of which embedded entities were contained within various transmission operator (TOP) footprints. Additionally, some TOPs did not understand the load-shed amount they were given included the total load connected to their transmission footprint and not just their entities' load. As a result, some entities may have not been included in the load-shed event and other entities may have had incorrect amounts of load shed requested of them.

LOAD RATIO SHARE FOR LOAD SHED

The load ratio share used to determine each TOP's share of the manual load-shed amount is based upon prior year energy use for a season. Some customers were proactive and voluntarily reduced their demand for electricity in response to public appeals or as part of an interruptible load program. The current paradigm does not recognize the contributions to the entire SPP region that these reductions provide. One way to recognize these contributions would be to calculate load ratio shares used for load shed based upon actual loads at the time of the event.

LOAD-SHED INSTRUCTIONS

On Feb. 16, 2021, SPP initiated a load-shed event for 1,350 MWs of BA load followed by a second load-shed event for an additional 1,350 MWs of BA load 33 minutes later. The result was confusion by several TOPs who were unsure if they had received a second load-shed instruction, or a secondary notification of the initial load shed instruction. SPP staff noted that the separate instructions were accompanied by unique R-Comm event IDs. Although a partial load restoration was not necessary, SPP was prepared to use the load-shed calculator if the need arose. There is an R-Comm enhancement underway that would allow for systematic processing of partial load restoration.

INTERRUPTION OF CRITICAL LOAD

During the load-shed events, there were concerns from TOPs that natural gas compressor station loads may be curtailed, exacerbating the fuel shortage issue and causing a need for additional load shed.

There are additional concerns that these critical loads do not have adequate backup plans to continue operating in the event of a loss of interconnection to the grid such as gas fired compression. Reliance upon the electric grid to power compressors will lead to interruptions in service due to other forced outages not initiated by the TOP.

CONCLUSIONS REGARDING EMERGENCY RESPONSE PROCESSES AND PLANNING

SPP's and its members' emergency response processes, including use of load-shed procedures, were effective in preventing uncontrolled, more significant loss of load but could be improved to increase effectiveness and appropriateness of load-shed actions.

EMERGENCY RESPONSE PROCESSES AND PLANNING RECOMMENDATIONS

Table 13: Summary of recommendations to the board related to emergency response processes and planning

#	TIER	CATEGORY	RECOMMENDATION
ERP 1	2	Assessment	Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations.
ERP 2	2	Action	Implement improvements to load shed processes to be developed by the Operating Reliability Working Group (ORWG), such as: • Utilize real-time load values when determining load-shed ratio shares. • Train and drill on multiple overlapping load-shed instructions. • Perform a detailed review of models used to determine load-shed ratio shares. • Develop and document procedures and processes to address the timing and responsibility of curtailing exports before and during a load-shed event.
ERP 3	2	Policy	Develop a policy to ensure TOP emergency response and load-shed plans have been reviewed, updated and tested on an annual basis to verify their effectiveness, with attention to critical infrastructure.

OPERATOR TOOLS, COMMUNICATION AND PROCESSES

During Feb. 15 and 16, 2021, there were constraints loaded above 115% of their emergency ratings post-contingent. SPP has processes that instruct staff to perform a cascading analysis for post-contingent loading levels above 115%. Although this is good practice, the results of these analyses are not available for TOPs for review.

When SPP issues out-of-merit-energy (OOME) instructions, there is not a consistent method to inform SPP real-time operations personnel when conditions have changed that will permit the release of all or part of the OOME instruction. In addition, there were locations where low-cost resources were manually dispatched down at the same time high cost resources were brought online at the same BUS.

There were times when the market was unable to solve congestion due to the violation relaxation limit (VRL) being less than the cost to move resources. This was exacerbated by an increase in the maximum energy price, but when the market doesn't have enough resources to balance load with resources and interchange and resolve congestion, the congestion will remain. It may be beneficial in the long run to identify pockets where load reductions would be the least costly to resolve congestion once the congestion has not been corrected for several market iterations. In addition, it may not be readily apparent to TOP operators the Market Clearing Engine (MCE) is not respecting this constraint because the cost to solve the congestion is greater than the VRL.

The R-Comm tool performed well throughout the event. Communications were timely and the information provided to the TOPs via R-Comm was timelier than other methods of communications. Especially when messages require acknowledgement, there is a high degree of confidence the message will be received. When R-Comm was originally rolled out, there were concerns TOP operators may not pay attention to the messages that were sent over R-Comm alone. This event demonstrates that R-Comm is an effective mechanism for real-time operations communications between SPP and its TOPs. At times, the additional blast calls and satellite phone calls served as more of a distraction rather than an enhancement of the communications process. These communications mechanisms can serve as a backup means of communication, but are not needed when R-Comm is functional.

While TOPs have avenues to view some SPP systemwide data, the paths are disjointed, and the data available does not provide a complete system overview. Offering TOPs a single tool that provides a complete system overview would help TOPs better understand the state of the SPP region in real time. Additionally, conservative operations alerts can have many different interpretations, ranging anywhere from business as usual to TOPs canceling and recalling outages. Associating conservative operations alerts with defined alert levels would give more meaning to the conservative operations alerts and help members react to the alerts accordingly.

The pre-event calls between SPP and the Operating Reliability Working Group (ORWG) members provided valuable communications on the situation unfolding. There were others in SPP who could have benefited from this information, and SPP could have benefited from others having this information firsthand. However, there was no readily available contact list that SPP could

utilize to quickly organize a conference call. Furthermore, it would be advantageous for SPP to develop email lists that utilize distribution lists developed by each operating entity for different types of notifications. SPP needs to identify whether each group may contain merchant employees or not. This will be determined by the type of information sent to each list. Having the entities maintain internal distribution lists with SPP just sending information to a single list, will place responsibility and control of who receives the messages within the membership. This may result in more up to date distribution lists.

CONCLUSIONS REGARDING EMERGENCY RESPONSE PROCESSES AND PLANNING

SPP's tools, communications and processes were largely effective during the winter weather event but should be improved to increase effectiveness and awareness among critical participants.

OPERATOR TOOLS, COMMUNICATION AND PROCESS RECOMMENDATIONS

Table 14: Summary of recommendations to the board related to operator tools, communications and processes

#	TIER	CATEGORY	RECOMMENDATION
OTCP 1	2	Action	Develop or enhance the tools, communications and processes identified by the ORWG and needed to improve SPP and stakeholder response to extreme conditions, such as: • Enhance real-time cascading analysis studies and post results. • Develop tool(s) to increase operator awareness of Out of Merit Energy (OOME) instructions. • Enhance and expand the use of R-Comm.[22] • Create a reliability dashboard to improve situational awareness for operators. • Utilize member-maintained distribution lists for communications purposes. • Develop a process to update operations management during extreme conditions.

[22] R-Comm is the Reliability Communications tool, the primary means of communication for responsible entities to receive, acknowledge and carry out load-shed instructions issued by the SPP Balancing Authority.

MARKET DESIGN

PRICING DURING EEA EVENTS

PRICE RESPONSIVE LOAD AND PRICING DURING LOAD-SHED EVENTS

During the Feb. 15 and 16 load-shed events, SPP observed intervals during which locational marginal prices (LMPs) dropped below $100. These lower LMPs may have sent the wrong signal to the market during a time when energy was needed so the load could be restored. The price formation and incentives for continued energy delivery may be improved during these times by modifying the pricing structure during load-shed events to continue to reflect prices associated with serving the desired amount of load and not the reduced amount of load due to the load shed. Incentives for price-responsive load in SPP's market may also improve the price formation during these times by allowing the market to determine load reduction based on offers and congestion.

VIOLATION RELAXATION LIMITS AND DEMAND CURVE PRICING DURING EMERGENCY CONDITIONS

During the event, SPP also observed instances where transmission constraint violations occurred due to energy offer prices exceeding the VRL price. Energy prices offered above the highest VRL price can overpower the cost to re-dispatch around transmission constraint that leads to these violations. The current VRL prices were set based on analysis using the FERC approved $1,000 energy offer cap. However, during the 2021 winter weather event or other emergency conditions when energy offers are greater than $1,000, these VRL prices may not be appropriate.

SPP also observed violations on the spinning reserve requirement and resource ramp rate constraints. Spinning reserve and resource ramp rates are priced as VRLs. These VRL prices may not provide transparent prices during events such as the 2021 winter weather event. SPP may desire to change these two requirements to be demand curves instead of VRLs, but this also means SPP must determine the appropriate price for these demand curves.

APPLICATION OF EMERGENCY LIMITS

During the 2021 winter weather event, system conditions dictated SPP release maximum emergency capacity operating limits in accordance with the prescribed language in both the Integrated Marketplace Protocols and Attachment AE of the SPP Open Access Transmission Tariff. This release of maximum emergency capacity operating limits allowed for DAMKT dispatch values up to these limits for a number of resources, including some VERs. Additionally, while the DAMKT used emergency capacity operating limits as prescribed by the governing documents, in real time, emergency capacity operating limits were not used due to operational concerns. This raises the question as to whether or not the application of maximum emergency

capacity operating limits is appropriate and provides the value SPP and the membership envisioned during the design of the Integrated Marketplace.

DAY-AHEAD MARKET AND MARKET-TO-MARKET

One purpose of SPP's DAMKT is to give generators and LSEs a means by which to schedule activities sufficiently prior to their operations. This is typically based on a forecast of their needs and consistent with their business strategies. Although SPP committed many resources for reliability reasons, rather than through the usual DAMKT process, the DAMKT continued to give reasonably accurate predictions of the operating day. The exceptions were Feb. 13 and 14, 2021, which SPP repriced after-the-fact.

While the DAMKT looks ahead and the market-to-market process focuses on real-time, they are traditionally both views as tools to further enhance economic benefits of the Integrated Marketplace, not to enhance reliability. During the 2021 winter weather event, their reliability benefits were evident. By committing resources through the DAMKT process, it reduced the dependency of capacity generation being required to be committed through the reliability unit commitment processes. During the event, this was critical, as it was even more vital to the overall capacity needs to the SPP footprint to ensure all available generation could be utilized appropriately.

Similarly, the market-to-market process's ability to use the combined generation fleet of both SPP and MISO to mitigate constraints further displayed its reliability benefits. The process allowed for a more systematic response than the alternative methods such as transmission loading relief (TLR). It also provided a mechanism for increased real-time communication on how mitigation of internal RTO constraints with internal generation would impact the neighboring RTO's constraints.

MULTIDAY RELIABILITY ASSESSMENT

SPP's Integrated Marketplace design consists of numerous unit commitment processes beginning with the multiday reliability assessment (MDRA), continuing with the DAMKT and concluding with the day-ahead, intraday and short-term reliability unit commitments (RUC). The purpose of the MDRA is to evaluate the reliability-based need to issue instructions to start to resources that cannot be committed in the day-ahead RUC because of their long lead time as well as committing resources as part of conservative operations, as outlined in the SPP BA EOP.

As part of conservative operations, SPP issued resource commitments of various lead times well in advance of the DAMKT to give early notice that the resources would be needed and to allow more time to procure the appropriate amounts of fuel needed for the duration of the event. Although similar commitments have been made as part of conservative operations in the past, the scale during this event was unprecedented and has allowed SPP to assess the processes, procedures and governing language associated with the MDRA process.

DISTPATCH TARGET ADJUSTMENT PROCESS

During the 2021 winter weather event, the SPP BA activated an operational tool downstream from the Real-Time Balancing Market (RTBM) clearing called Dispatch Target Adjustment (DTA). This tool lives in the emergency management system (EMS) application RTGEN. The DTA tool is typically used by SPP operations to balance the SPP region in times when the MCE is not functioning properly or not working at all.

During the 2021 winter weather event, the SPP BA used the DTA process to ensure its ability to balance the region and keep ACE in check due to insufficiencies in cleared operating reserves from the RTBM and due to uncertainty around the timing of curtailed tags from MISO. Notably, the RTBM cases continued to solve and approve, publishing new dispatches and LMP every five minutes. DTA takes the last solved and approved RTBM and adjusts the resulting setpoint as needed to chase the load using the marginal cost calculated in that RTBM. While the setpoint adjustments were generally in merit and updated as RTBM cases approved, there were many instances where resources were positioned out of merit and financially harmed.

MARKET DESIGN RECOMMENDATIONS

Table 15: Summary of recommendations to the board related to market design

#	TIER	CATEGORY	RECOMMENDATION
MKT 1	2	Policy	Develop and improve policies to ensure price formation and incentives reflect system conditions.
MKT 2	2	Action	Develop and implement market design and market related enhancements identified by the Market Working Group to improve operational effectiveness and ensure governing language provides needed flexibility and clarity, such as: • Improve the Dispatch Target Adjustment Process. • Enhance the Multiday Reliability Assessment Process.
MKT 3	2	Policy	Develop policies to ensure financial outcomes during emergency conditions are commensurate with the benefits provided.

TRANSMISSION UTILIZATION AND PLANNING

CONGESTION

Congestion describes a condition when usage of transmission facilities exceeds reliable operating limits. SPP and neighboring areas experienced very high levels of congestion during the winter event. Congestion particularly posed challenges, as an abnormally high number of transmission system constraints[23] experienced high loading. Many constraints were as much as 10-20% above their post-contingency operating limits, and some were near real-time operating limits. Primary contributors to system congestion during the focused period of Feb. 15-19 included, but are not limited to:

- Winter peak load levels.
- High import flows from neighboring systems into SPP.
- High export flows into ERCOT from SPP including schedules using firm transmission.
- MISO regional directional transfer flow at times in excess of the 3,000 MW north-to-south contractual limit.
- Unrecallable transmission outages.
- Congestion and operational challenges in neighboring systems.

Mitigation methods utilized to manage system congestion included, but are not limited to:

- Market redispatch.
- Out-of-merit-energy (OOME).
- Transmission Loading Relief (TLR).
- Post-contingent load shed plans.

Table 16 shows some mitigating actions that occurred Feb. 15-19. Market breached/bound transmission constraints indicate those for which SPP was actively trying to redispatch generation as a mitigation method. Only SPP member-owned constraints are included and, as these are daily counts, one constraint may recur multiple days. OOME counts include each unique resource instruction (e.g., an OOME cap issued for a resource at 100 MW and later reduced to 50 MW will be reflected as two OOMEs). TLRs are those issued by SPP. For reference, the 2016-2020 daily average number of OOMEs issued on any day in February is less than one,

[23] Transmission system constraints are transmission elements or groups of elements that limit or constrain distribution of electricity due to necessary imposition of reliable operating limits. Constraints are sometimes referred to by the industry as "flowgates."

and the daily average number of breached/bound constraints for the same time periods is 15.3 constraints.

Table 16: Daily mitigation summary (Feb. 15-19)

DAILY COUNT ITEM	FEB. 15	FEB. 16	FEB. 17	FEB. 18	FEB. 19
Market Breached/Bound Constraints	43	54	22	19	24
OOME	25	41	4	9	10
TLR	2	1	0	0	0

Figure 30 shows the number of SPP member-owned constraints that were overloaded during each hour Feb. 15-16. The sharp drop in the number of overloaded constraints that occurs after 7 a.m. Feb. 16 is due in part to SPP system load shed. Certain constraints may fall into multiple overload categories for a particular hour. The chart captures all instances of constraint loading in each category and does not necessarily indicate that loading persisted at high levels for the entire hour. For example, a constraint that was loaded at 105% for 20 minutes and loaded at 115% for 10 minutes would be captured in both the >100% and the >110% categories for a given hour.

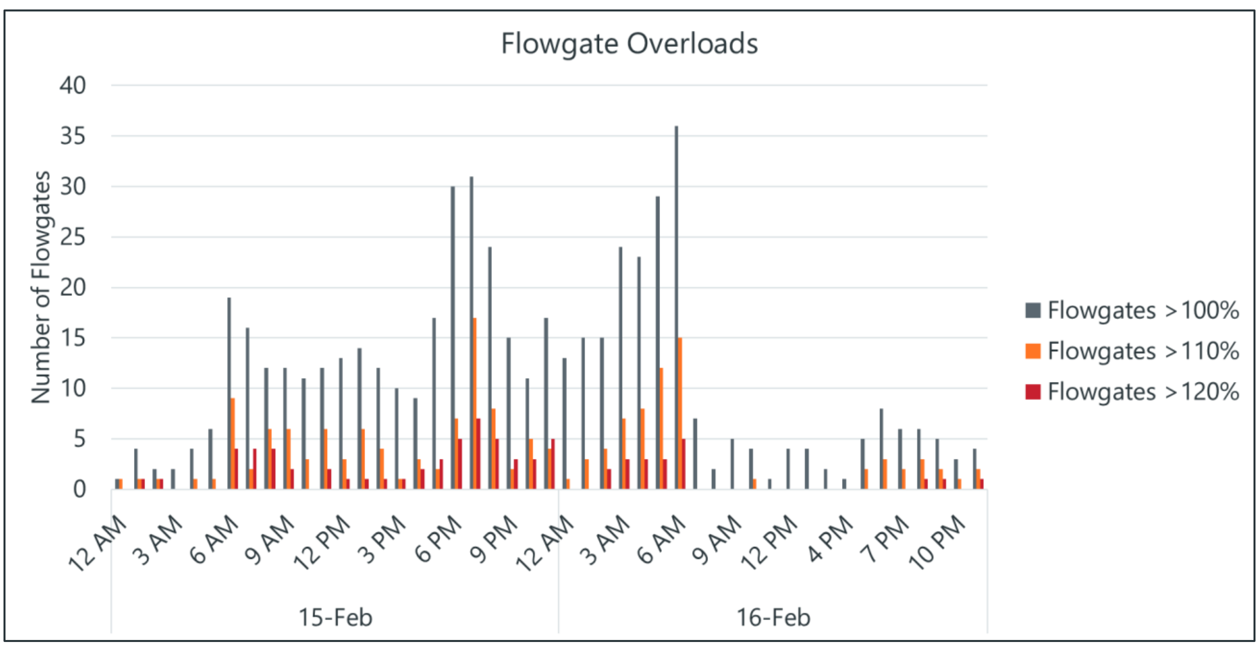


Figure 30: Hourly constraint overloads (Feb. 15-16)

Constraints loaded at or above 115% post-contingent are considered 'severely loaded.' These constraints are analyzed further by real-time staff to determine if they pose a potential risk to

the interconnection. Analysis includes running contingency analysis studies with both the monitored and contingent facilities removed from service to look for cascade type situations. During Feb. 15-19, real-time contingency analysis (RTCA) identified several constraints loaded over 115% post-contingent. The specific regions captured Figure 31 were particularly subject to severe loading.

Region	Flow Direction	Contributing Factors	Primary Reliability Concerns	Mitigation Actions
Western Kansas	NW → SE (into SPP)	• Heavy imports into SPP • 345 kV line outage	• Real-time overloads • Potential loss of load pocket • Low voltage	• OOME • Post-continent load shed plan
Eastern Nebraska Eastern Kansas	NE → SW (into SPP)	Heavy imports into SPP	Potential for widespread issues for the loss of 345 kV path	• TLR • OOME
Western Kansas	E → W (into SPP)	• Heavy imports into SPP • 500/161 kV transformer outage	• Potential voltage collapse in northern Arkansas • Real-time overload on 500 kV line	• TLR • OOME
Eastern Texas	E → W (into SPP and ERCOT)	• Heavy imports into SPP • Area generation trip	• High post-contingent loading in SPP • MISO concerns due to real-time overloads • Low voltage	TLR

Figure 31: Regional overview of severe loading

INTERCHANGE WITH NEIGHBORING ENTITIES

During the event, SPP observed the highest level of imports into its market since it went live in March 2014. SPP reached total imports of higher than 7,500 MW during the event and reached a total net scheduled interchange of more than 6,000 MW of imports. These imports were needed to help SPP meet demand and reserve obligations throughout much of the event. Figure 32 shows exports and imports by firm and nonfirm status for Feb. 10-20.

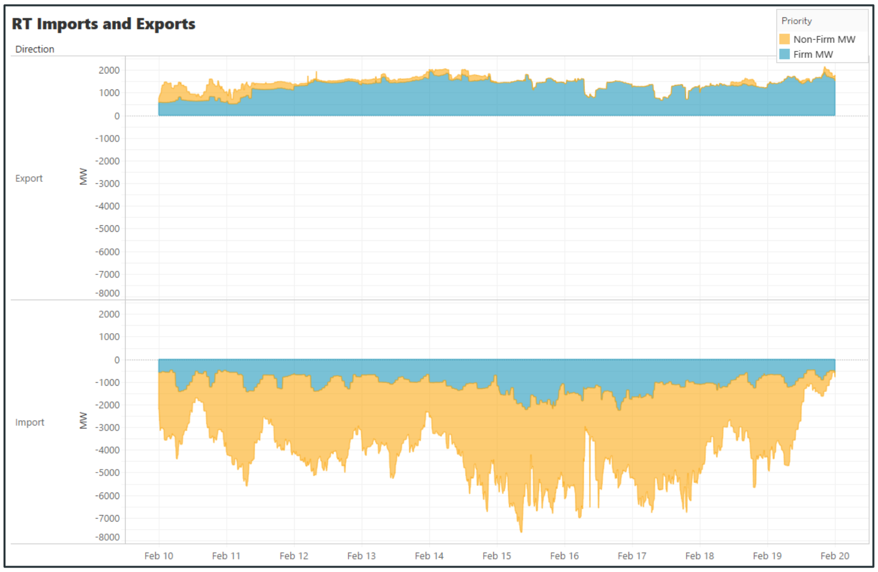


Figure 32: Real-time imports and exports by status (Feb. 10-20)

Curtailment of imports was a key factor in the necessity to shed load on both Feb. 15 and 16. Figure 33 provides a closer look at real-time imports and exports during critical time periods.

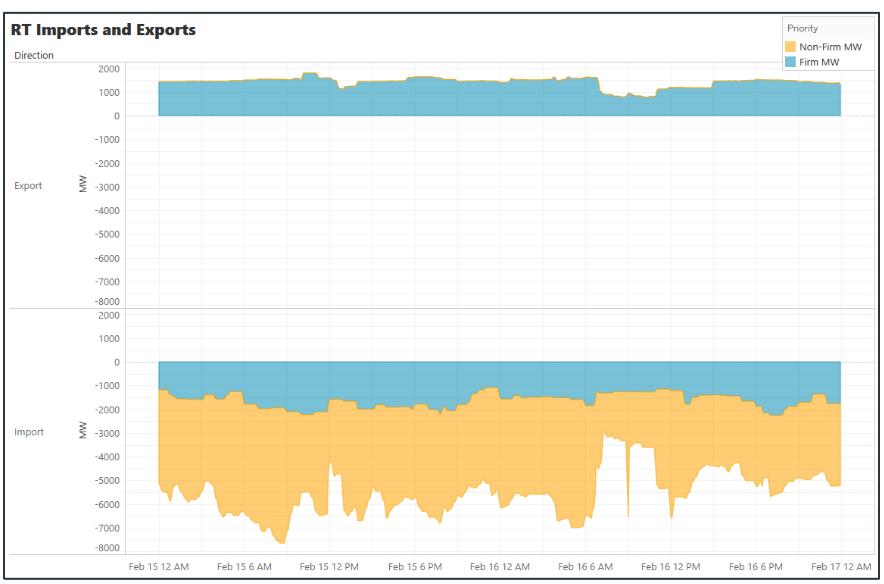


Figure 33: Real-time imports and exports by priority (Feb. 15-17)

The following figures illustrate SPP's net interchange with the remainder of the eastern interconnection during load-shed timeframes. On Feb. 15 (Figure 34), TLR curtailments effective at 12 p.m. reduced energy imports into SPP. Once energy imports were restored, SPP could instruct load restoration.

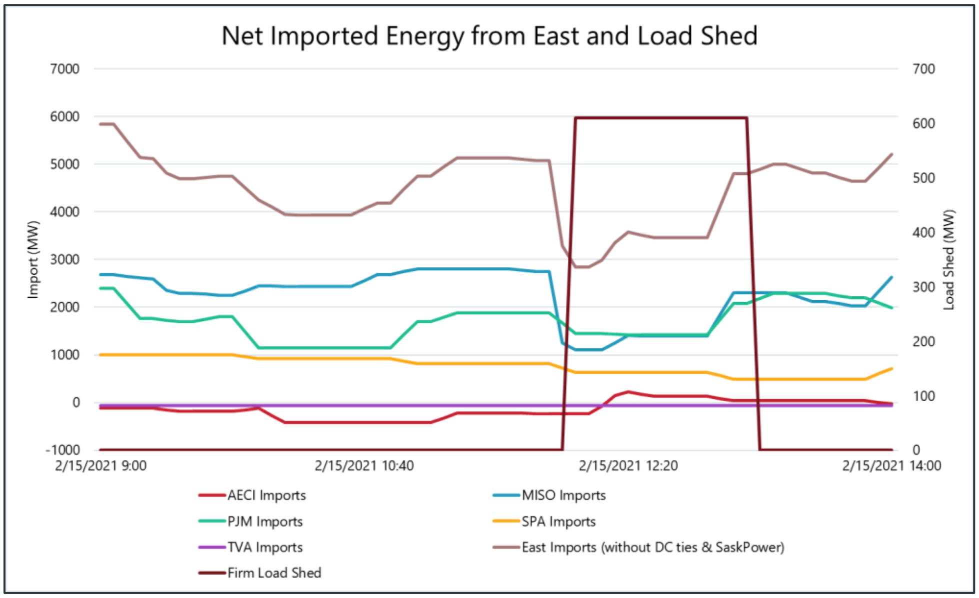


Figure 34: Eastern Interchange (Feb. 15, 2021)

As illustrated in Figure 35, on Feb. 16, schedule curtailments effective at 7 a.m. reduced energy imports into SPP. The sudden spike in imports that appeared shortly after 8:30 a.m. was the result of an inadvertent schedule adjustment during execution of the curtailments that was quickly corrected.

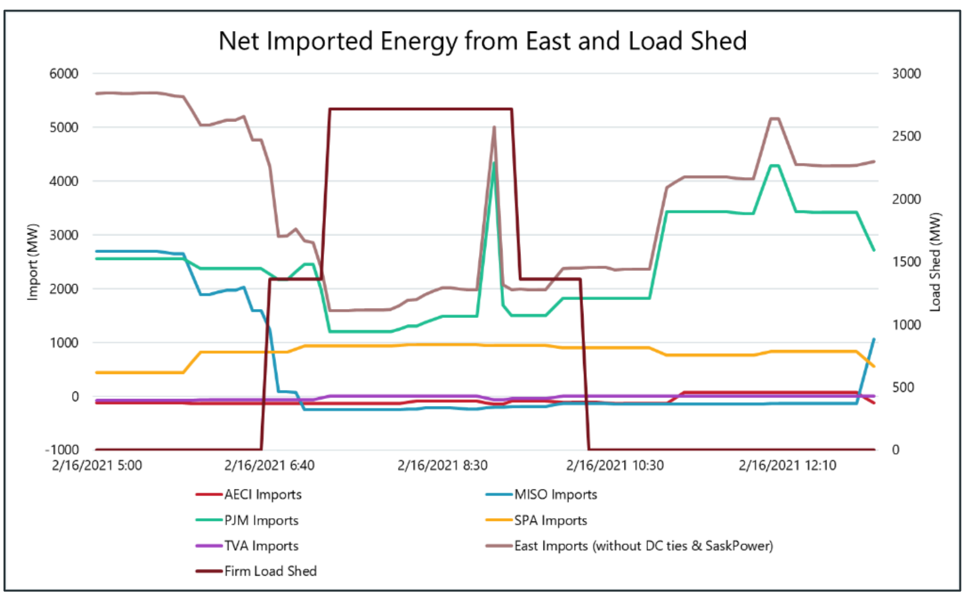


Figure 35: Eastern Interchange (Feb. 16, 2021)

WESTERN INTERCONNECT TIES

Seven DC ties connect SPP to the Western Interconnection. During the winter event, four of the seven ties were in service. The three ties that were not operable were out of service in advance of the winter event on scheduled outages. Figure 36 shows flows across the operable DC ties during Feb. 15-16. Negative values indicate flows into SPP.

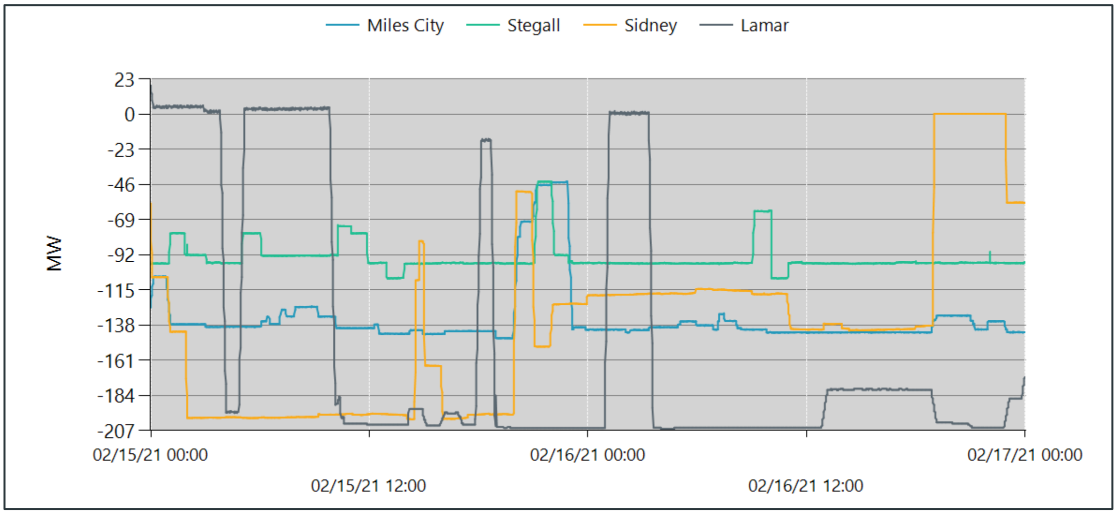


Figure 36: West DC Tie Summary

ERCOT TIES

Two DC ties connect SPP and ERCOT. Both were in operation during the winter event. Figure 37 shows flows across the ERCOT DC ties Feb. 15-16. Positive values indicate flows into ERCOT. At times, ERCOT DC ties were reduced due to curtailments associated with EEA 3 conditions in SPP and TLR curtailments from IDC due to congested constraints.

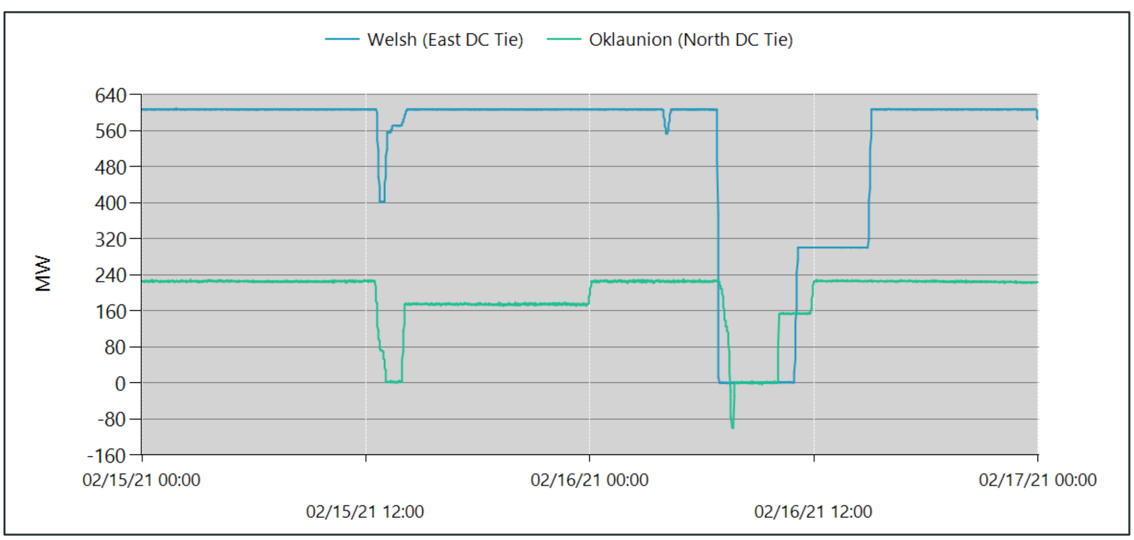


Figure 37: ERCOT DC Tie Summary

SASKPOWER PHASE SHIFTER

SaskPower (Saskatchewan, Canada) connects to SPP through a phase-shifting transformer. This tie was used to import power into SPP during the winter event. Figure 38 shows flows across the SaskPower phase shifter Feb. 15-16. Negative values indicate flows into SPP.

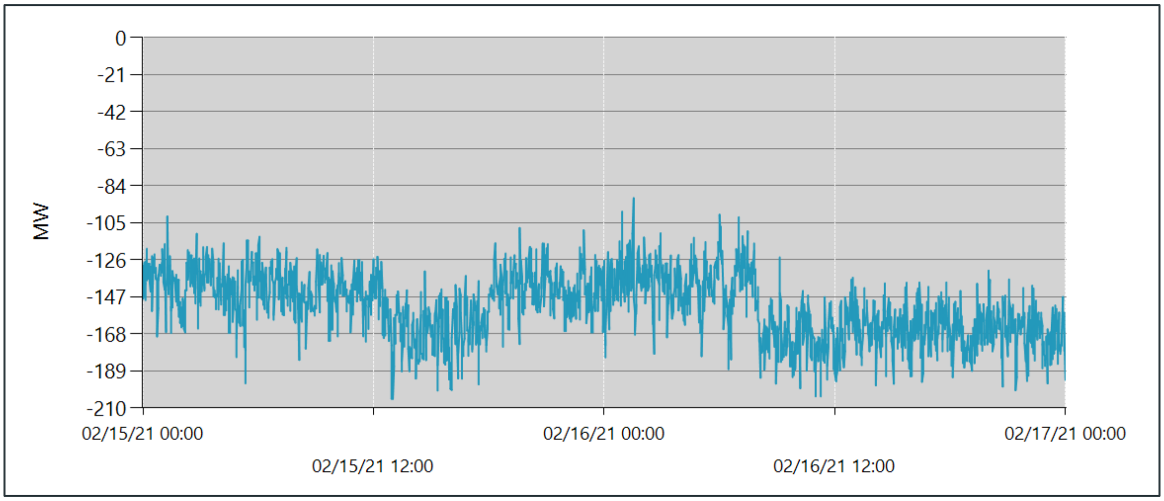


Figure 38: SaskPower Phase Shifter Flow

CONCLUSIONS REGARDING TRANSMISSION UTILIZATION AND PLANNING

Adequate transmission to deliver power is critically important in decreasing the impact of future extreme conditions, provides added resilience and could mitigate the need to implement load-shed procedures.

Although severe congestion was experienced at times during the 2021 winter weather event, significant investments that have been made over the last 10-15 years to upgrade the SPP transmission system allowed SPP to more fully utilize the generating resources that were available. SPP also was able to rely on capability of the broader transmission network to import significant amounts of energy from its neighbors. Transmission, both within and outside SPP, proved critical and beneficial in avoiding longer controlled interruptions of service.

Future evaluations of transmission needs should consider impacts of severe events.

This increased transmission utilization during the event pointed to the importance of appropriately assessing the deliverability of a dispersed set of resources across the Eastern Interconnection during such times. The event and congestion that existed also highlighted that SPP should improve efforts in the transmission planning study processes to evaluate adequate transmission capacity needed during normal and emergency conditions. Other forms of energy and an increased focus on improving the transmission system are critical to decrease the

possibility of further controlled interruption of service to customers. The 2021 winter weather event is a credible scenario that needs to be adequately scrutinized to understand potential impact of such events and protect against as SPP plans for the future (gas unavailability and the inability to meet demand with intermittent resources).

TRANSMISSION PLANNING RECOMMENDATIONS

Table 17: Summary of recommendations to the board related to transmission planning

#	TIER	CATEGORY	RECOMMENDATION
TXP 1	2	Policy	Develop policies that facilitate transmission expansion needed to improve SPP's ability to more effectively utilize the transmission system during severe events.
TXP 2	3	Policy	Develop transmission planning policies that improve input data, assumptions, or analysis techniques needed to better account for severe events.

SEAMS AGREEMENTS AND EMERGENCY ASSISTANCE

The SPP market relies on price signals to incent market participants to submit import interchange transactions when energy supply becomes limited. However, there may be situations where these commercial import interchange transactions are insufficient for the SPP BA to maintain adequate operating reserves and SPP must initiate an EEA in accordance with NERC Reliability Standards. Assistance from neighboring BAs and RTOs may need to be relied upon to provide emergency energy during these situations.

SPP had seams agreements with each of its neighbors during the winter weather event, but those agreements had inconsistent provisions regarding the exchange of and compensation for emergency energy. SPP relied heavily on imported energy provided by neighboring entities during the event, including from those with whom SPP has a seams agreement.

Certain agreements require that the requesting entity be in an EEA Level 2 or higher, that the emergency energy be formally requested, and that the amount (MWs) and duration be coordinated. As specified in these agreements, emergency energy transactions are intended to continue only until they can be replaced by normal commercial transactions. The rates and charges associated with these emergency energy transactions include a transmission charge and an energy portion.

Other agreements contain provisions specifying expectations for sharing emergency energy but do not specify payment terms. When emergency energy is provided pursuant to those

agreements, the provider is subject to prevailing market prices. The lack of specific payment terms in these agreements denies those providers certainty that they may recover costs associated with providing emergency energy. Lack of certainty could dis-incent the provision of available emergency assistance in the future.

CONCLUSIONS REGARDING SEAMS AGREEMENTS

During the 2021 winter weather event, SPP relied heavily on emergency assistance it received, but the inconsistent terms and provisions in current seams agreements create uncertainty going forward and should be addressed.

SEAMS AGREEMENTS RECOMMENDATIONS

Table 18: Summary of recommendations to the board related to seams agreements

#	TIER	CATEGORY	RECOMMENDATION
SEAMS 1	2	Action	Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance and fairly compensate emergency energy.

ANALYSIS OF FINANCE, SETTLEMENTS AND CREDIT

Extreme cold, increased electricity use, high price of natural gas and limited generation resulted in dramatic price increases across SPP's Integrated Marketplace footprint. SPP experienced historically high market settlements for the impacted operating days: $16.3 billion have been settled for Feb. 13-19. Figure 39 shows the sum of payments made to (MP Credits) and collected from (MP Charges) market participants (MP) from August 2020 to June 2021. The dramatic spikes in the invoice totals are due to the high prices during the event's operating dates.

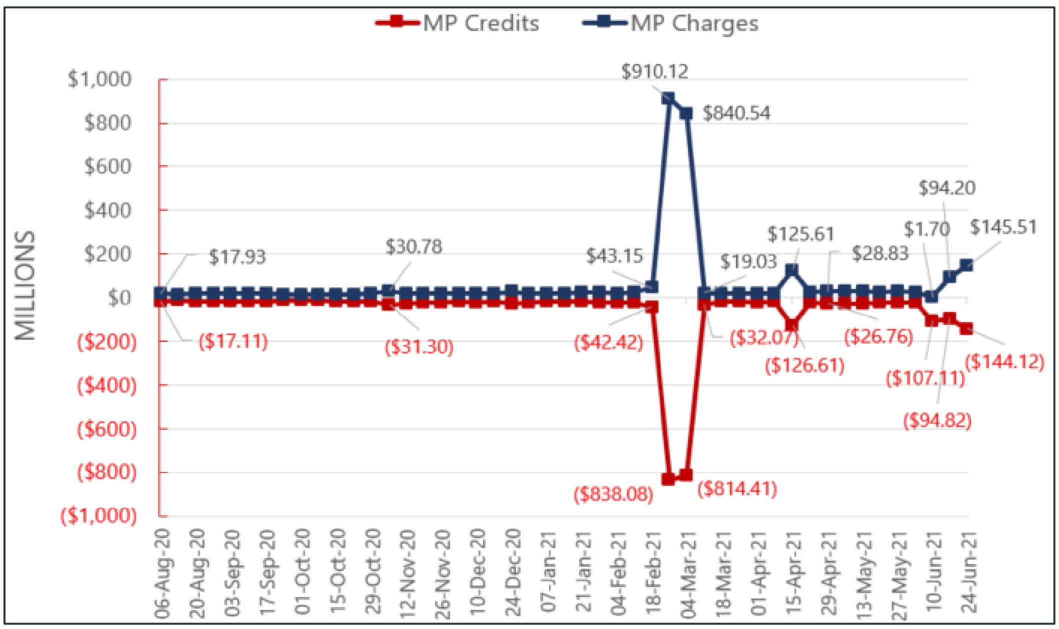


Figure 39: Weekly Marketplace Invoice Amounts (August 2020-June 2021)

Note: The June 10 invoice included the yearly ARR/TCR closeout dollars paid out on the last day of the planning year (May 31).

COST OF ENERGY

74% of settlement dollars ($12.13 billion) were due to various energy product charge types. Energy settlement dollars are paid to resources for injecting energy into the market and collected from load for consuming it. Prices were much higher than the typical averages for February. Due to the emergency status of the RTO and the need to find as much generation as possible, the DAMKT was committing all available units. In some cases, uneconomical units were committed, which resulted in high prices and led to a larger than normal volume of commitments in the DAMKT compared to the real-time balancing market (RTBM).

ORDER 831 – OFFER CAPS

SPP implemented tariff and system changes to comply with FERC Order 831. The order requires that each resource's incremental energy offer be capped at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer, as well as capped verified cost-based incremental energy offers at $2,000/MWh. Energy offers over $1,000 must be approved by the Market Monitoring Unit (MMU) before the start of the market (DA, RUC and RTBM).

SPP and the MMU filed a joint waiver with FERC to adjust the timelines for submission and verification of final costs and to align timing of deadlines with the anticipated timing of when generators would receive their final gas invoices.

MAKE-WHOLE PAYMENTS (MWP)

14% of total settlement dollars during the event were the result of make whole payments (MWP) to generators to make them whole to their costs (offers) in the market. A total of almost $880 million was paid out to resources that supplied energy in the DAMKT during the impacted days. That amount was funded by MPs with energy withdrawals in the DAMKT. An additional $220 million in MWP was paid in the RTBM to make generators whole to their real-time energy provided. RT MWP are funded by cost causers: virtual offers, deviations between day-ahead and real-time market for loads and imports/exports, and generators that deviate in real time.

SETTLEMENTS

Settlement calculations are performed for each operating day using the data available at that time. In addition to the three 'standard'[24] settlement postings, resettlements can be scheduled *as needed* following the S120 settlement posting for a given operating day. An MP may dispute items included in a settlement statement (or invoice) according to the following criteria established in the tariff/protocols.

There was a significant increase in settlement disputes as a result of the event. Many of the disputes were expected to be resolved with the posting of the S120 settlements. Some have already been granted upon verification that the issues were resolved.

MARKET PARTICIPANT CREDIT

The event created credit requirements never before seen for many of SPP's MPs. Market participants who were net purchasers of energy during the event experienced significant post-event collateral liabilities. The severity of energy prices could have potentially created a liquidity

[24] Standard settlement postings occur seven, 53 and 120 days after the operating day. These are referred to as the S7, S53, and S120 postings

crisis in the energy market and caused some participants to default on collateral calls or payment obligations. FERC approved a waiver extending the timing of collateral calls, which assisted load-serving utilities with capital management.

The event also exposed many MPs to payment of significantly higher natural gas invoices than normal and their accompanying collateral requirements from suppliers. Some participants were simultaneously exposed to neighboring energy markets that also experienced sustained and severe price spikes.

SPP's credit policy (Attachment X of the tariff) reacted aggressively to sudden and extreme energy price increases. By design, it assumes that swings in trading volumes and/or energy prices indicate sustained trends. Market participants with extremely high energy invoices were also required to post collateral to ensure future payments could be made. Many collateral requirements significantly outran the unsecured credit allowances granted by SPP.

During the event, the MMU calculated that virtual energy participants made $400 million in the market. The MMU expressed that had prices "gone the other way," SPP's market may have been exposed to credit/payment defaults from some of these financial-only participants.

Total potential exposure (TPE) calculations for day-ahead and real-time energy were ineffective in dealing with the short-term, temporary price spikes. The TPE would have required temporary collateral postings up to five times higher than actual invoice liabilities, inconsistent with the specific event risk. FERC's waiver effectively helped maintain liquidity, assuming all load-serving entities paid their invoices in full and on time.

Virtual reference prices may have undervalued credit risk during scenarios where actual DA/RT variances were greater than the reference prices used for credit exposure calculations. The extreme pricing experienced during the 2021 winter weather event may also have an adverse impact on the calculations of virtual reference prices for first quarter 2022.

DATA ISSUES

A number of factors had an impact on the data provided to settlements. There have been no identified issues with the settlement calculations, only the upstream data provided to the settlement system for use in the calculations:

- **Multiday reliability commitments:** A software error incorrectly locked in resources from Feb. 13 through Feb. 14. Software changes allowed offers to be updated starting Feb. 15, but analysis found this change did not completely fix the issue.
- **Day-ahead reprice:** Original DAMKT results for operating days Feb. 13 and 14 were not accurate as a result of commitments and prices based on MDRA offers, rather than updated offers. This caused prices to be much lower than if correct offers were used and impacted the day-ahead quantities awarded.

- **Order 831 offer caps:** As a result of MMU-verified offers pushed for Feb. 13 and 14 (due to the MDRA software error), some previously settled MWP were clawed back in the S120. For Feb. 15-19, the majority of offers were not approved before the market closed, and S120 MWP increased as offers were verified and approved by MMU.
- **Other data issues:** SPP was in a dispatch target adjustment (DTA) anytime an EEA 2 or above was declared. Unlike previous usage of DTA, the market continued to solve in these instances. Some resources were moved counter to the offer provided to the market. The decision was made to settle DTA time periods as out of merit energy.

EMERGENCY SCHEDULES

Four neighboring entities submitted emergency schedules to provide assistance to SPP during the event. The majority were settled via the normal settlement process, with some limited manual adjustments via processes outlined in SPP's seams agreements.

SPP ACCOUNTING

SPP utilizes automated clearing house (ACH), a form of electronic funds transfer that settles usually the day after a transaction is initiated to pay MPs on a weekly basis. SPP also uses ACH to debit the accounts of those MPs owing SPP for their market invoices and who have elected to have such amounts drawn from their accounts by SPP. Due to the next-day-settlement nature of ACH payments, banks impose limits on their customers for ACH transactions to mitigate their credit risk. The event resulted in the total amount of weekly market ACH payouts and ACH receipts being exponentially larger than SPP's ACH limits with its bank for a two-week period in March.

SPP'S PERFORMANCE OF FINANCIAL FUNCTIONS

The new settlements system enabled SPP to be efficient, flexible, collaborative and proactive during the settlement of the winter event operating days. The efficiency of the new system, including the ability to process and validate manual data files to address data issues in real time, provided a means to deliver financial data to other departments and to the officer team quickly for consideration in the decision-making process.

SPP's credit department was able to use this data to research and analyze various scenarios that might have resulted in potential credit default events. As a result, staff filed a waiver request approved by FERC to extend the collateral call timeframe to help ensure liquidity in the energy market during the event. Staff was able to coordinate with all of the significantly affected utilities to provide data for their capital management and to ensure payments were made in full and on time.

As soon as SPP's ACH issue became known, staff reached out to and regularly updated its bank to explain the event and to alert them about the issue with the upcoming large ACH

transactions. SPP and the bank were able to temporarily switch to an ACH process called ACH secured funds, resolving limit issues and ensuring MPs received their payments on the regular payment due date. All transactions cleared on time with no problems and with no adverse or unexpected impacts on MPs.

CONCLUSIONS REGARDING CREDIT AND SETTLEMENTS

MDRA commitments resulted in data scenarios that are not typically seen in the market. In many cases, the tariff does not provide clear language with regard to how SPP systems should treat these scenarios. There should also be consideration given to where the tariff is lacking and what additional language is needed to avoid similar data issues should there be another weather event that impacts the SPP footprint.

Some scenarios encountered during the event weren't addressed in the original 831 compliance filing. SPP and the MMU will collaborate to understand these impacts and potential need for future changes to the tariff language, market processes and settlement calculations.

SPP should consider changes to the language filed with FERC regarding cost submissions and verification timelines. The timeline outlined in the tariff is not feasible in instances like those experienced during the event. SPP may also consider working with FERC to establish possible changes to capping levels based on the emergency status of the RTO.

The current design of the market allows for participation of non-asset owning MPs or financial-only participants. In some cases, these financial-only MPs benefited greatly from these events. Further analysis should be conducted to determine if these payments are appropriate and if the current design of the market is sufficient.

CREDIT AND SETTLEMENT RECOMMENDATIONS

Table 19: Summary of recommendations to the board related to credit

#	TIER	CATEGORY	RECOMMENDATION
CR 1	2	Assessment	Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in 1Q'22.
CR 2	3	Assessment	Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes.
CR 3	3	Action	Clarify tariff language related to SPP's settlements and credit-related authorities and responsibilities.

ANALYSIS OF COMMUNICATIONS

Throughout the February 2021 winter weather event, SPP used a number of communication channels to keep members and public throughout its service territory apprised of changing grid conditions. Operators followed clearly defined protocols for coordinating with member utilities.

In its analysis of communications before, during and immediately after the event, the Communications Comprehensive Review (CCR) team sought to identify ways to improve the accuracy, timeliness, reach and overall effectiveness of future emergency communications. To do so, they conducted several analyses and gathered input from several specific stakeholder audiences.

First, the CCR team evaluated the timeline and content of written communications during the week of Feb. 14-20. This review helped the team identify where messaging could have been clearer, where the sequence of communications activities was either helpful or problematic, why some messages were timelier than others and whether the appropriate audiences received the right information at the right time.

Second, the team conducted surveys of specific stakeholder groups to gauge their assessment of SPP's storm-related communications. The team surveyed:

- Members of the Regional State Committee (RSC) and Cost Allocation Working Group (CAWG), and representatives of SPP's member and market participant companies, to gauge the overall effectiveness of SPP's emergency communications.
- SPP's officers and directors to assess the time they spent communicating with individual stakeholders during the winter storm and to identify opportunities to make more effective use of leadership resources during emergency events.

Third, SPP staff and stakeholders conducted interviews with television, radio and newspaper journalists who reported on SPP's activities during the winter storm. The team sought to learn whether SPP's public relations activities during the winter storm were effective and appropriate.

Fourth, SPP facilitated discussions with stakeholders to learn more about the impacts of SPP's communications activities. Over a series of virtual meetings, the CCR explored stakeholders' experiences and emergency response activities, sought context for SPP's event data, and identified lessons learned and best practices that could be applied in future emergencies.

Lastly, the CCR team reviewed the effectiveness of SPP's public communications tools: SPP's website, social media channels, press releases and email distribution lists. Staff reviewed and shared SPP's website analytics, including up and downtime, traffic and frequently visited pages; social media analytics regarding the reach and engagement of storm-related posts; and reports of newspaper, web, television and radio coverage of SPP's storm response.

Overall, SPP's stakeholders were satisfied with and felt appropriately informed by SPP's emergency communications efforts. SPP's surveys of stakeholders showed strong ratings of the effectiveness of SPP's communications, a majority of respondents agreed that SPP's communications increased their trust in the organization's credibility.

There were, however, opportunities to improve communication practices for future emergency events. Before the cold weather event, SPP's communication and updates to members was beneficial and helped prepare the members for the event. Once the event began, the need for frequent communication increased, as did the size and complexity of SPP's audience.

SPP and its members and other stakeholders can improve communications by working together to improve communication with broad audiences and to clearly delineate communications roles during emergency events. A coordinated communication effort can reach all critical audiences with the information they need to take appropriate action and to reduce misunderstanding. A summary of the CCR's findings is included below, and more detail is available in their full report published on SPP.org.[25]

TIMELINE OF COMMUNICATIONS

Beginning Feb. 4, 2021, SPP issued several weather alerts, conservative operations declarations and emergency energy alerts. Figure 1, provided in the section labeled Events of Feb. 4-20 shows the times each of these alerts was declared.

Each of the following sections examines the timeline of SPP's communications with different audiences related to these operational events.

OPERATIONAL COMMUNICATION

Operational communication differs from other types of communication because it is almost exclusively between SPP operations and member company operations staff. This operator-to-operator communication happens daily under normal operations but was thrust into the public eye during the winter weather event.

SPP used R-Comm for the majority of its operational communications. Other communication channels used were email, phone calls and the Open Access Same Time Information System (OASIS) an internet-based information and scheduling system for electric power transmission services.

[25] "A Comprehensive Review of SPP Communications during the Feb. 2021 Winter Storm: Analysis and Recommendations"

CONCLUSIONS REGARDING OPERATIONAL COMMUNICATION

When examining operator-to-operator communication, the team looked at many data points including survey results, analysis of the existing energy emergency alert (EEA) process and comments and feedback from operational staff.

SPP worked with members' corporate communications departments to issue public appeals on Sunday, Feb. 14 to reduce load on days following. The timing allowed customers to be aware and appeared to significantly reduce load compared to forecast during the highest load periods. The North American Electric Reliability Corporation (NERC) Attachment 1 of EOP-011-1 does not recommend public appeals to reduce load until a balancing authority reaches an EEA level 2. Issuing public appeals does require some time to make the appeal and for customers to respond. It seems more reasonable to have an appeal issued in advance of the event when possible.

SPP and nonoperational stakeholders should routinely drill load-shed and other procedures to prepare for future events. SPP should encourage consistent assessment, updates and testing of member emergency plans and communication with attention to critical infrastructure.

Stakeholders felt SPP should have provided earlier operator notifications to individuals in member organizations outside of operations staff. They should create an operational event early notification process, using R-Comm, OASIS or other operational system alerts, for key stakeholders. During long events, SPP operations should provide interim updates to member company operations staff.

Before the cold weather event, SPP's communication and updates to members were beneficial and helped prepare the members for the event. Once the event started, communication between SPP and the members reduced. Increased communication during these time would help the members' operations staff understand the current situations and what is needed.

If operational system alerts are utilized for nonoperations staff and the public, SPP should develop talking points, graphics and other materials that simplify and explain these alerts for broader audiences.

SPP should designate dedicated subject matter experts for communication during events.

STAKEHOLDER COMMUNICATION

SPP used various platforms to reach stakeholders, including alerts from its emergency communication tool, xMatters, emails to exploders and distribution lists, daily webinar briefings, social media and website updates.

Beginning Feb. 14, SPP issued press releases and alerts about the winter weather event and its impact on system conditions. These notices continued throughout the week to inform

stakeholders and customers of changing conditions, concluding with an alert issued Feb. 19 noting that SPP had ended its EEA1 state and returned to conservative operations.

Daily briefings were also held with stakeholders throughout the week of the event. These daily briefings helped communication efforts tremendously. The briefings helped members communicate with their end-users and equipped them with consistent language, resources and materials to explain the event to public audiences.

Additionally, SPP officers hosted calls with members, reached out to individuals and provided open and direct lines of communication.

SPP's communication efforts were greatly helped by the years of preparation staff had done before the event to build relationships with member communication staff. This included an annual testing of its emergency communication system, developing contact lists and hosting annual communication conferences.

CONCLUSIONS REGARDING STAKEHOLDER COMMUNICATION

While there were many things that SPP did well when communicating with stakeholders, the CCR identified areas for improvement.

More preparation is needed ahead of any future events. SPP should reassess who receives emergency alerts and tools for updating contacts. They should consider defining a "calling tree" procedure that clearly assigns responsibilities for communicating with specific audiences and implement a process to regularly update contact lists.

Many stakeholders felt communication should have been earlier and more varied. SPP should identify opportunities to send members notices about more alert levels and provide more detailed event information to points of contact identified at each organization. SPP should consider more effective and frequent communications on other aspects of the event, including market and repricing activities.

There are many efforts SPP and member companies can do together to improve communication to stakeholders, including coordination of press releases and media briefings. The planning of media briefings should be done with members and local utilities with enough time for them to coordinate their own local press briefings as a follow-up. They should also work to develop educational materials that explain SPP's and members' load-shed procedures or responsibilities.

GOVERNMENT AFFAIRS AND REGULATORY COMMUNICATION

As conditions started to deteriorate, SPP staff alerted member company government affairs representatives, the SPP Regional State Committee (RSC) and Federal Energy Regulatory

Commission (FERC) staff about worsening conditions in our footprint. This was done in a variety of ways through emails, phone calls and webinars. SPP also sent emails to U.S. congressional offices as well as governor offices and state energy offices across the SPP region, apprising of changing conditions throughout the week of the event.

CONCLUSIONS REGARDING GOVERNMENT AND REGULATORY COMMUNICATIONS

SPP identified opportunities for improvement when communicating with government affairs staff and regulatory officials.

Early in the storm, SPP included government relations staff on communications to member company communication staff. This helped to ensure messaging was getting to the right individuals. In the future, SPP should examine additional opportunities for collaborative communication between SPP's government affairs and regulatory teams and consider including member government affairs and regulatory staff earlier and on more notifications.

Contact list management impacted SPP's ability to reach government affairs and regulatory representatives. Some lists were outdated due to election-related turnover. SPP may more frequently update contact, improve contact-update processes for public officers, or consider tools to allow self-updates.

More frequent joint calls and webinars with the RSC, CAWG, member government affairs and regulatory staff and elected officials would ensure more consistent communication and address some concerns from stakeholders who felt communication to these groups was insufficient. SPP should have clear emergency points of contact for RSC and other public officials, and examine opportunities for rapid notification of certain alerts from operations to commissioners.

SPP should develop educational materials and resources about SPP, RTO/TOPs and energy emergencies for government affairs and regulatory staff, state commissioners, congressional offices and governors' offices. Staff should look for opportunities to remind officials of the benefits of RTO services in event communications.

PUBLIC COMMUNICATION

During the winter weather event, SPP distributed nine press releases and provided 10 informational updates regarding grid conditions. These were sent to various groups including stakeholders, news release exploder subscribers, media outlets with whom SPP had developed relationships, member company communication staff and posted to www.spp.org. When possible, member company communication staff were given previews of releases to create consistent messaging.

SPP communication staff received an influx of media inquiries at the onset of the event. In addition to our regular media contacts, we received inquiries from a large number of small, local news outlets across the footprint. The most inquiries came from Oklahoma, but all SPP states were represented. We also received inquiries from media outside the footprint.

It quickly became apparent the request load was too large to respond to all inquiries individually. At that point, SPP decided to host daily press briefings. SPP held three daily "State of the Grid" briefings for news media and stakeholders with 924 attendees across three days. These livestreams were broadcast by some affiliate networks, and recordings of each briefing were posted on social media.

SPP saw increased traffic on its website. After the first EEA3 was declared Feb. 15, SPP experienced rapid increases in website traffic, slowing or interrupting site access for some users. These spikes in traffic often followed social media posts, especially about EEAs or impending outages. Due to the increased traffic, SPP created a grid conditions page where current alerts, definitions of alert levels and a timeline with each new event were posted.

Throughout the storm, SPP posted updates to Twitter, Facebook, LinkedIn and Instagram. The first post to social media about the storm was the Feb. 14 press release. Between Feb. 14 and Feb. 20, 42 Twitter tweets, 24 Facebook posts, 23 LinkedIn posts and 18 Instagram posts were made.

On Twitter, SPP gained 5,479 followers and had 3.5 million engagements with posts. On Facebook, SPP gained over 12,000 page likes and had over 160,000 engagements.

Facebook engagement escalated quickly, peaking Feb. 15 and began to decline Feb. 16. Twitter impressions peaked quickly and declined more slowly. LinkedIn and Instagram had far fewer engagements than Facebook or Twitter.

SPP communications posted five videos during the winter weather event, including the three recordings of the "State of the Grid" news briefings and two "explainer" videos. The explainer videos were titled "Who is Southwest Power Pool?" and "Why was power interrupted during this storm?" and featured SPP officers. These video postings resulted in 8,800 views, totaling over 1,000 hours, and 139 new YouTube subscribers.

CONCLUSIONS REGARDING PUBLIC COMMUNICATIONS

SPP gained invaluable insight from managing social media during the winter weather event that will help navigate social media platforms in the future, both during normal operating circumstances and emergencies.

During a multiday event, day one is the most critical time to engage social users. Spikes in engagement are short-lived, and SPP should use these temporary increases in engagement to their advantage to reach as many people as possible. SPP should focus on using the most effective platforms, and SPP received the most engagement on Twitter and Facebook. In the

future, SPP should utilize Twitter and Facebook for real-time notifications since they provide the most engagement. Graphics that explain the status of the grid and what to do will get high engagement. To combat negative sentiment scores, SPP can change messaging to better empathize with end-user challenges and combat misinformation by collaborating with news outlets and members.

Because there was limited engagement on LinkedIn and Instagram, it may not be worth the time to monitor and create real-time content for these platforms during emergencies. These platforms may be better utilized for post-event information or pre-event educational materials. Since Facebook proved to be the greatest driver of traffic to videos, SPP should prioritize video sharing on that platform primarily.

SPP received positive feedback on both the daily briefing and explainer videos. While the explainer videos received more views than videos posted under typical circumstances, the recordings of the daily "State of the Grid" briefings were the most watched. Audiences wanted to know who SPP is, but they wanted to know what was happening more. In light of this information, SPP should consider promoting daily briefing information on social media platforms before they begin. SPP can better utilize video in emergencies by preparing videos in advance for a public audience that are tailored to emergency events.

SPP staff interviewed four reporters from a local newspaper, local public radio, industry publication and a local TV station anchor to gather feedback on its communication with media. This audience represented a variety of media outlets and covered the majority of the SPP footprint. Each of the reporters indicated they got their news from a mix of sources including SPP's social media, emails from SPP, its website and communication with member companies and would likely continue to use a variety of sources in the future. All reporters said they would benefit from educational and other related materials posted on the SPP website before the event or sent in conjunction with press releases.

In the wake of the storm, there may be demand for direct education from SPP to news media, and SPP should consider an annual media day in collaboration with members to educate the public on who SPP is, who are their members are, the benefits they provide and how they work together to protect the grid.

SPP received such a flood of media requests at the onset of the winter weather event that the "State of the Grid" press briefings became critical for responding to media and providing public updates. While feedback from media told SPP these briefings were helpful, SPP should consider a mix of morning and afternoon briefings to better meet the needs of the different types of reporters.

SPP's media briefings were often livestreamed by local news outlets. Knowing this, SPP should work to create messages tailored for the public, and ensure speakers receive proper media training. To reach a broader audience at briefings, SPP can improve promotion of briefings and its news distribution sign-up process.

The electric industry is complex, and information regarding the status of the grid can be difficult to communicate. This event highlighted the need to improve public emergency communication. Press releases should use clear, simple terms and be free of industry jargon. All communication should provide up-to-date information, local utilities impacted by the event, and simple actions to take.

SPP's website is a valuable source of information, but winter weather event was a unique test of its capabilities. It experienced rapid increases in website traffic, hindering the distribution of information. From this, SPP learned how large traffic spikes can be during emergency events and what should be done to mitigate against the risk of negative impacts to the site due to increased traffic. SPP should increase server capacity ahead of weather events and more clearly label banners on the site. Throttling and file reduction can help to reduce disruption further.

KEY FINDINGS RELATED TO COMMUNICATIONS

Overall, SPP's stakeholders were satisfied with and felt appropriately informed by SPP's emergency communications efforts. In a survey of 155 representatives of SPP's member and market participant organizations, 80% rated the overall effectiveness of SPP's communication during the winter storm either "effective" or "highly effective." In a survey of SPP's RSC and CAWG, 85% of respondents rated SPP "effective" or "highly effective." More than 70% of stakeholder respondents and 55% of RSC and CAWG respondents agreed or strongly agreed that SPP's communications increased their trust in the organization's credibility.

There were exceptions to stakeholders' satisfaction with SPP's emergency communications. Some individuals did not receive information in as timely a manner as they would have liked. In many cases, this occurred because SPP sent communications to particular points of contact at its stakeholder organizations and that information was not further disseminated within those organizations.

Some stakeholders were unsure what to do with the information they received during the event. While SPP and its member operators had already developed and practiced response procedures, some other stakeholders were unsure of their roles during the event. This event marked the first time some audiences in the SPP region had heard of or from SPP.

The electric utility industry is complex, and SPP's role is usually "behind-the-scenes." General audiences (including the public, media and elected officials) lack an understanding of the variables that affect the reliable delivery of electricity on a regional scale. SPP tends to communicate using technical language that may be useful for industry professionals but contains too much jargon for general audiences.

The winter weather event exposed a need for better coordination between SPP, members and distributors to communicate about load shed. As the event worsened and threat of outages became real, audiences who were previously unaware of SPP's role became interested in the RTO's load-shed procedures. They wanted to know what factored into SPP's decisions

regarding Energy Emergency Alerts, calls for conservation and load curtailment. A spike in interest and a need to communicate complex concepts to new audiences proved a challenge.

Post-event analysis confirmed that SPP's transmission-operating and load-serving member utilities all received and responded to load-shed communications in a timely manner. Utilities quickly brought the system into balance and SPP restored load quickly and effectively.

Long after the outages, SPP and its members continued to field questions from distribution companies, regulators, reporters and the public about SPP's authority to curtail load, SPP's and its members' roles in choosing what load to curtail and why curtailing load was necessary.

COMMUNICATIONS RECOMMENDATIONS

Table 20: Summary of recommendations to the board related to communications

#	TIER	CATEGORY	RECOMMENDATION
COMM 1	2	Action	Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: • Processes that ensure stakeholders have a dependable way to receive timely, accurate and relevant information regarding emergencies. • Plans to drill emergency communications procedures with all relevant stakeholders. • Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers, and government entities and stay up-to-date.
COMM 2	2	Assessment	Evaluate and propose needed enhancements to communications tools and channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc.
COMM 3	3	Action	Form a stakeholder group whose scope would include discussion of matters related to emergency communications.
COMM 4	3	Action	To increase public awareness of and satisfaction with SPP, develop materials intended to educate general audiences on foundational electric utility industry concepts and SPP's role in ensuring electric reliability.

CONCLUSION

The February 2021 winter weather event was historic in nearly every respect, from the widespread and severe nature of the storm itself to the response it required from SPP and its stakeholders to preserve the reliability of the regional grid. SPP credits its success in responding to the winter storm to its many partners, including its member utilities, neighboring systems and millions of people who voluntarily made sacrifices to conserve energy in the interest of the greater good. Likewise, SPP owes its stakeholders thanks for their thoughtful and deliberate contributions to this report.

In a statement to SPP's staff on Feb. 18, in the immediate aftermath of the storm, SPP's president and CEO wrote the following regarding the organization's obligation to learn from the experience:

> *"We will do our best and we will come out on the other side wiser and more prepared for the future. Will we learn from the events of this week? Definitely. We will identify improvements? Most certainly. Will our best be even better next time? Absolutely."*

Many of the factors that contributed to the severity of the February storm's impacts were externalities that SPP could not control: low temperatures, the duration of the storm and fuel prices set by gas providers, for instance. Similarly, SPP and its stakeholders will almost inevitably face other crises that arise from circumstances they cannot prevent, whether they result from natural disasters, mechanical failures or acts of terrorism. This comprehensive review, though, demonstrates the SPP organization's commitment to doing everything in its power to safeguard the reliability and affordability of electricity delivery in its region.

As this report's name suggests, SPP's analysis of its response to the February storm was comprehensive. The results are indicative of dozens of meetings in which hundreds of stakeholders spent thousands of hours considering how to achieve SPP's mission — responsibly and economically keeping the lights on today and in the future — even when facing the toughest challenges imaginable. This report does not mark the end of SPP's learning process, though. From here, with direction from SPP's independent board, SPP will set about the ongoing process of continuing to engage stakeholders in making the recommended improvements. Where assessments need to be made, plans carried out or policies written or amended, SPP staff will partner closely with stakeholders, because SPP's success, in the past, present and future, depends largely on the strength of its stakeholder engagement.

APPENDICES

APPENDIX A: SPP'S ROLES IN ASSURING ELECTRIC RELIABILITY

SPP serves in a number of capacities related to the coordination of the regional power grid. Those most relevant to the February 2021 winter weather event are its roles as a regional transmission organization (RTO), reliability coordinator, balancing authority and market administrator.

SPP AS AN RTO

As an RTO, SPP is granted specific responsibilities by the Federal Energy Regulatory Commission (FERC). Rates, terms and conditions by which SPP oversees the regional power grid and coordinates with its member utilities are defined in a FERC-approved tariff. 106 member utilities in 14 states are members of the SPP RTO, meaning they have placed their power plants and extra high-voltage transmission facilities under SPP's functional control. RTO membership is voluntary, though the member roster has steadily grown since SPP became an RTO in 2004 because of the value the organization provides: enhanced reliability and cost savings as compared to the status quo of utilities operating on their own.

SPP AS A RELIABILITY COORDINATOR

As a reliability coordinator (RC), SPP functions like an air traffic controller for electricity. Air traffic controllers don't own skies, planes or airports they coordinate. Similarly, SPP doesn't own power plants, transmission lines or electricity, but it directs these and other components of the bulk power system to ensure electricity is delivered safely and affordably from where it's generated to where it's used in real time. RC activities are governed by the North American Electric Reliability Corporation (NERC), who enforces standards related to the reliable operation of the country's bulk electric system. (For more information on the standards most relevant to the winter event, see the Applicable Standards and Regulations section.)

SPP staffs a 24/7 control room and backup facility from which it maintains constant communication with member utilities. RC staff constantly plan for contingencies and operate from an N-minus-one posture, meaning they work to keep the grid ready to respond to the next worst contingency such as the loss of our largest generating unit. SPP keeps operating reserves online equivalent to one-and-a-half times its region's largest generating unit. This means it keeps enough generation online to meet real-time demand and enough "spinning" and ready to flow onto the grid immediately if committed generation becomes unavailable.

SPP AS A BALANCING AUTHORITY

The nation's power grid comprises three interconnections: Eastern, Western and ERCOT (Texas). Each is a single massive, highly interconnected network of generators, transmission lines and substations that feed power to local distribution networks that serve homes and businesses. Disturbances anywhere on one of these networks are felt across the entire interconnection. The SPP RTO is part of the Eastern Interconnection.

As a balancing authority (BA), SPP keeps real-time production and consumption of electricity in balance. It does this for its entire 14-state balancing authority area. Other entities serve as the BAs in other regions, big and small, across the country. Production and consumption of electricity must be kept nearly perfectly in balance to prevent equipment failures and the potential for large-scale, cascading outages. In the absence of utility-scale energy storage devices like batteries, electricity is produced, transported, delivered and consumed nearly simultaneously. Damage to the grid can occur if either more or less energy is produced than is needed at that time. SPP forecasts demand (also called load) in five-minute increments, and sends signals to 800+ generators in its BA area to ensure they're collectively producing just enough power to meet demand without overloading lines or burning out equipment.

SPP AS A MARKET ADMINISTRATOR

SPP facilitates a wholesale electricity market that automates selection of the cheapest available energy to serve load minute-by-minute. SPP's market is fuel-agnostic, meaning it doesn't favor any particular fuel type over another but treats coal the same as wind, natural gas the same as nuclear power, etc. The market only takes into account the price at which generators offer energy into the market, and it picks the least-cost power available to meet demand, taking into account operating characteristics such as lead times (the amount of time it takes a generator to spin up from inactivity), minimum run-times, etc.

SPP's is a day-ahead market, meaning it commits generation a day in advance. As the region nears real-time, intraday market processes make additional commitments to ensure the right amount of generation is online as weather patterns, electricity use and other factors vary from forecasts.

Like its tariff, SPP's market design is approved by FERC, and its administration is overseen by an independent market monitor that watches to ensure the market operates fairly and without undue influence by any single participant or group of like-minded participants. SPP is a not-for-profit organization, registered as a 501(c)(6) in the state of Arkansas. As a market administrator, it facilitates the sale and purchase of power through its market, and SPP administers the process by which those transactions are invoiced and settled, but it does not profit off these activities. SPP is completely funded by an administrative fee charged to our members and market participants based on the use of our services.

In summary, SPP is authorized and regulated by FERC to carry out certain responsibilities related to the reliable operation of the regional power grid. It is required to comply with enforceable NERC standards, and its staff works around the clock every day to ensure energy production and consumption are held in balance while planning against contingencies that could threaten reliability. SPP's market helps do this by committing the least-cost generation that's available to serve load.

APPENDIX B: PREPARATION AND TRAINING

SPP holds its operators to exceptionally high training standards, ensuring every operator exceeds NERC's minimum training requirements and is equipped to respond to a wide array of operational issues. This includes specific training that addresses cold-weather events. SPP's operators work on six-week shifts, which include one week every rotational schedule dedicated to training.

NERC requires system operators to undergo 200 hours of training every three years to maintain their RC certification. SPP holds its operators to standards above those requirements, ensuring every one receives 85-100 hours of training every year. SPP also requires every operator to be certified both as an RC and on the specific functions they perform.

SPP requires its operators to receive training consistent with NERC Standard PER-005. Additionally, it requires operators to complete emergency operations training annually consistent with standards EOP-006 (System Restoration), EOP -011 (Emergency Operations), IRO-008 (Reliability Coordinator Operational Analyses and Real-time Assessments), IRO-009 (Reliability Coordinator Actions to Operate within IROLs) and PRC-001 (System Protection Coordination).

Operators typically earn 65-80 continuing education hours (CEH) annually from events developed and delivered by SPP's customer training staff. These training events — also attended by SPP members' operators — include Regional Emergency Operations (REOPS) classes, Power System Restoration drills, System Operations Conferences, and classes that focus on specific topics like conservative operations, event reporting, energy emergency alerts and unit commitment fundamentals. Many of these sessions include training specifically intended to prepare operators to respond to cold-weather events, and plans are already underway to update training content that incorporates circumstances and lessons learned from the February 2021 winter weather event.

Operators also receive training delivered by SPP's operations analysis and performance support (OAPS) team. This training, which does not count toward NERC CEH requirements, is based on real-world situations that might occur in SPP's control room and addresses topics like communications, the potential loss of a control center, remedial action schemes, capacity emergencies, severe loading transmission emergencies, load shed and energy emergency alerts. OAPS training typically provides every operator 30-35 hours of role-specific training each year.

SPP also performs R-Comm training to review how the SPP BA uses R-Comm to issue load-shed instructions and how entities are expected to respond to the communication.

LOAD-SHED TRAINING

SPP's operations staff performs load-shed tests every 11th Wednesday. SPP does not test individual TOP plans, but some TOPs inform SPP when they test their demand-side load-shed plans.

SPP operations engineering staff review documents that members submit related to NERC EOP standards, including load-shed plans. SPP reviews TOP or BA-submitted plans within 30 days of receipt to:

- Confirm that notification to the RC is included when experiencing an operating emergency.
- Mitigate operating emergencies regarding any reliability risks identified between operating plans.
- Confirm compatibility and interdependency with other BA and TOP operating plans.
- Confirm coordination to avoid risk to wide-area reliability.
- Review and confirm any communication information listed for SPP.
- Review each document for consistency with SPP criteria and procedures when interactions with SPP are required.
- Review each topic discussed for criteria and compare against SPP's operating criteria.

APPENDIX C: APPLICABLE STANDARDS

Below are the NERC standards most relevant to SPP's and its members' obligations during the winter weather event.

- Emergency Preparedness and Operations (EOP): EOP-011-1 - Emergency Operations.
- Transmission Operations (TOP):
    - TOP-001-4 – Transmission Operations.[26]
    - TOP-002-4 – Operations Planning.
- Resource and Demand Balancing (BAL): BAL-001-2 - Real Power Balancing Control Performance.
- Interconnection Reliability Operations and Coordination (IRO): IRO-001-4 - Reliability Coordination – Responsibilities.

[26] TOP-001-4 was in effect during the event but was retired and replaced with TOP-001-5 on April 1, 2021.

APPENDIX D: PRIOR RELIABILITY EVENTS

Before the February 2021 winter storm event, the SPP and neighboring regions experienced extreme winter weather conditions in 2011 and 2018 that resulted in two joint Federal Energy Regulatory Commission and North American Electric Reliability Corporation (FERC/NERC) reports. [27,28] The 2011 event report made 26 recommendations for the electric industry and six for the gas industry, including improved coordination between the electric and gas industries. Recommendations for the electric industry focused on five areas: planning and reserves, coordination with generator owners and operators, winterization, communication and load shedding. The 2018 event report contained 13 recommendations related to generator cold weather reliability, situational awareness, reliability coordinator communications, seasonal studies, system operating limits, reserves and load forecasting.

As part of SPP's comprehensive review following the February 2021 event, an assessment of the previous event recommendations was conducted. SPP's current operational and planning processes and tools incorporate a majority of the applicable recommendations from both events.

FEB. 1-5, 2011, SOUTHWEST COLD WEATHER EVENT

This event involved extremely low temperatures, wind, snow and ice. Electric entities located within three NERC regions, the Texas Reliability Entity, Inc. (TRE), the Western Electricity Coordinating Council (WECC), and SPP were affected by the extreme weather, as were gas entities in Texas, New Mexico and Arizona. While three balancing authorities (BA) in the SPP footprint issued varying levels of energy emergency alerts (EEAs), no load shedding occurred, and SPP was not directly mentioned in any of the recommendations.

SPP was not a BA at the time of the 2011 event, but due to SPP's current NERC registrations as a BA, planning coordinator (PC), transmission planner (TP), reliability coordinator (RC), reserve sharing group (RSG) and transmission service provider (TSP), a number of the recommendations were considered for potential improvements to SPP's operational and planning processes. Some recommendations are specific to the Electric Reliability Council of Texas (ERCOT) and WECC, but due to SPP's current NERC registrations, these were included as part of the comprehensive assessment.

[27] https://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/SW_Cold_Weather_Event_Final.pdf

[28] https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

PLANNING AND RESERVES

The 2011 event report recommended that all entities responsible for the reliability of the bulk power system in the Southwest prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season. Recommendations included augmenting studies with scenarios like the 2011 winter conditions and changing operating practices to allow increased lead time for generator preparations, canceling previously scheduled outages and increasing reserves.

SPP conducts seasonal planning assessments as part of the integrated resource planning process. These assessments consider scenarios across a broad range of weather conditions, including seasonal generator capabilities. Extreme scenarios are included in NERC Transmission Planning Standards (TPL), Under-Frequency Load Shedding (UFLS) and annual transfer capability studies. SPP's planning criteria specifies generator testing requirements and generator owners and operators convey current information on seasonal capabilities including fuel switching, fuel supply and black-start capability.

SPP's staff works constantly to prepare for a range of expected and unexpected operational conditions by evaluating various scenarios based on short and midterm weather forecasts. These uncertainly levels are incorporated into the load and wind forecast outlook in the multiday resource availability assessments. Recommendations are provided to generator operators (GOPs) if early commitments are needed and SPP relies on the generators to make appropriate preparations, which can include pre-warming. SPP's personnel, processes, and systems have the ability to manage the clearing and delivery of operating reserves through reserve zones.

COORDINATION WITH GENERATOR OWNERS AND OPERATORS

Several recommendations involve coordination between transmission operators (TOPs), BAs and GOPs to develop mechanisms to verify generator capabilities such as fuel-switching, black-start capability and temperature performance. SPP's planning criteria includes testing requirements for generating units that incorporates seasonal parameters.

SPP also holds an annual winter preparedness workshop and transmission operators and generator operators typically give presentations on their upcoming winter preparedness. Attendees include members of SPP's ORWG. The 2020-2021 winter preparedness workshop was Sept. 29, 2020.

COMMUNICATIONS

This event highlighted the need for better communication about emergency situations between BAs, RCs and other market participants. SPP utilizes a number of communications including cold weather alerts, resource alerts and conservative operation notices. SPP's Reliability Communication Tool (R-COMM) is used to facilitate operator to operator communication between SPP and TOPs, BAs and RCs. The tool is also used by TOPs, BAs and RCs to communicate with SPP and each other.

ELECTRIC/GAS COORDINATION

This event highlighted many areas for improvement between the electric and gas industries. Recommendations included working with state regulators to adopt standards to winterize critical gas systems, allow critical gas systems to be exempt from load-shedding plans, and prioritize demands on gas supply. Electric/gas coordination requires engagement by numerous stakeholders at the federal and state level and across multiple agencies. After the 2011 event, SPP has been involved in efforts at the North American Energy Standards Board (NAESB) and NERC to improve coordination between the electric and gas industries.

- *North American Energy Standards Board*

  In both 2014 and 2016, NAESB undertook gas-electric harmonization (GEH) in response to a FERC directive. During that time, SPP worked with gas operators within our footprint to improve coordination and to make changes to the market bidding timeline.

- *North American Electric Reliability Corporation*

  SPP has been involved in the NERC Electric Gas Working Group who has been updating a guideline that includes recommendations to improve electric gas coordination. The guideline focuses on the areas of preparation, coordination, communication and intelligence that may be applied to improve gas and electric coordinated operations and minimize interdependent risks. The guidance is not a "one size fits all" set of measures but rather a list of principles and strategies that can be applied according to the circumstances encountered in a particular system, balancing authority, generator fleet or even an individual generator operator.

SOUTH CENTRAL COLD WEATHER EVENT JAN. 17, 2018

Below-average temperatures resulted in 183 individual generating units within the reliability coordinator footprints of SPP, Midcontinent Independent System Operator (MISO), Tennessee Valley Authority (TVA) and Southeastern Reliability Coordinator (SeRC) experiencing either an outage, a derate or a failure to start between Jan. 15-19, 2018. All of the recommendations from this event were reviewed, although a number of the recommendations were specific to MISO.

NERC RELIABILITY STANDARDS

The 2018 report recommended a three-pronged approach to ensure generator owners/generator operators, RCs and balancing authorities prepare for cold weather conditions, including the development of new or enhanced reliability standards. Recognizing the importance of the 2018 recommendations to improve operations, communication and coordination during extreme winter weather conditions, SPP sponsored the Standard Authorization Request (SAR) that led to NERC's winter weather reliability standard project. (Project 2019-06 Cold Weather.)

SPP led the industry's effort to finalize the SAR that was approved by NERC's Standard Committee. SPP chaired the Standard Drafting Team (SDT), and through NERC's collaborative process with interested stakeholders, the project recently received strong industry support. The project focuses on the first prong of the recommended approach and includes three revised reliability standards related to emergency preparedness (EOP-011-2), RC data specification and collection (IRO-010-4) and operational reliability data (TOP-003-5).

The NERC board of trustees adopted the project during a special session June 11, 2021, and authorized staff to file it with FERC.

SITUATIONAL AWARENESS

In the 2018 event report, FERC/NERC acknowledged that the relevant RCs (MISO, SPP, TVA and SeRC) had situational awareness throughout the event and communicated as necessary to preserve system reliability. However, four of the recommendations focused on situational awareness since the event involved large power transfers across four RCs. Performing additional studies and scenarios based on event conditions and conveying the results of the analysis to adjacent RC areas was recommended. Voltage stability studies were recommended, and SPP's voltage stability analysis tool became operational in mid-2018. SPP has implemented a process to identify additional study types for different constraint types that includes communication steps with adjacent RCs and impacted TOPs.

SPP and other RCs conduct capacity and energy drills on a periodic basis and system transfer scenarios are included in the training. The Jan. 17, 2018, State Estimator case was used to formulate customer training scenarios for six sessions in 2020. SPP will also conduct a pilot for the capacity and energy exercise for FERC to attend on Sept. 8, 2021, and the joint exercises with MISO on Sept. 23, 2021, and Oct. 7, 2021.

RC TO RC COMMUNICATIONS

To improve RC-to-RC communications, the 2018 report also made specific language change recommendations to the Regional Transfer Operating Procedures (RTOP). The recommendations were meant to provide more specificity to certain sections and improve communications related to Regional Directional Transfers and analysis of flow impacts. SPP is part of the Regional Transfer Operating Committee (RTOC) who owns the RTOP. Following the January 2018 event, the RTOC adopted modifications meeting the intent of the 2018 report recommendation, although some work remains.

SEASONAL STUDIES

The 2018 report recommended that RCs and PAs study more extreme conditions that include removing generators in their entirety, extreme condition load forecasting and benchmarking of actual events. The report also recommended that MISO and SPP perform seasonal transfer studies. SPP and MISO had calls in 2019 and 2020 to discuss worse case scenarios to be

included in seasonal studies. SPP and MISO coordinated and developed a few common scenarios for winter 2021 for multiple contingencies and extreme conditions (similar to Jan. 17, 2018) to identify constraints on seams that may be difficult to mitigate with normal congestion management processes. Operating guides were developed and reviewed with neighboring RCs and impacted TOPs. These scenarios will be provided to the training department for them to develop RC and TOP training including load shedding.

SYSTEM OPERATING LIMITS

This recommendation applied to the establishment of facility ratings by TOs and TOPs and the provision of those ratings to the RC for use in applications such as the Energy Management System (EMS) and Real-Time Contingency Analysis tools. SPP has a Rating Submission Tool used by TOPs to submit facility ratings. SPP staff reviewed this recommendation with RTO stakeholders in the Transmission Working Group (TWG) and ORWG to stress the importance of this recommendation.

RESERVES

The reserve recommendations focused on the deliverability of reserves, and MISO's communication with other RCs when it needs to rely on any amount of nonfirm, as available portion of the Regional Directional Transfer (RDT) to meet its reserves. All BAs have deliverability assurance processes in place. SPP has reserve zones modeled in the SPP Market System and can use those as needed. SPP staff reviews market solutions daily and this includes looking for stranded reserves. MISO and SPP's RCs communicate often during abnormal operating conditions and when MISO is depending on RDT to meet reserves.

LOAD FORECASTING

The load-forecasting recommendations were specific to MISO; however, their forecasting team reached out to SPP and staff reviewed load forecasting best practices. MISO is working on a forecasting survey with other ISOs/RTOs and will share the results with SPP upon completion.

SUMMARY

SPP is committed to identifying and improving our own processes and quickly initiated a comprehensive assessment of the February 2021 event, including a review of FERC and NERC recommendations from past winter events. We have determined SPP's current processes and tools encompass the majority of recommendations from the 2011 and 2018 events.

FERC and NERC began a review of the 2021 event on Feb. 16, 2021, and the results of the inquiry are not expected until this fall. SPP will review the recommendations from the inquiry and if not previously self-identified, will evaluate for inclusion in our implementation plan(s).

It is unknown at this time whether NERC or NAESB will undertake projects to improve electric-gas coordination or develop new or revised standards as a result of the 2021 event, but SPP will engage in projects as appropriate to improve the reliability of the bulk power system during extreme events.

APPENDIX E: COMMUNICATIONS SURVEY OF RSC AND CAWG MEMBERS

EXECUTIVE SUMMARY

The SPP communications department launched the RSC - Winter Storm Event Survey March 30, 2021, and closed the survey April 9, 2021. Staff distributed survey invitations to the 10 members of the Regional State Committee (RSC), the 11 members of the Cost Allocation Working Group (CAWG), and extended an invitation to complete the survey to the Texas Office of Public Utility Counsel (OPUC).

Ten RSC commissioners, nine members of the CAWG, and one member of the Texas OPUC completed the survey. The distribution of respondents by state is shown in Table 1.

Table 1: Respondents by State

State	Respondents
Arkansas	2
Iowa	2
Kansas	2
Louisiana	2
Missouri	1
Nebraska	2
New Mexico	2
North Dakota	2
Oklahoma	2
South Dakota	2
Texas	1

On a scale of zero to four, with zero being "Highly Ineffective" and four being "Highly Effective," survey respondents gave an average rating of 2.95 when rating SPP's overall effectiveness during the winter storm event.

Table 2: Overall Effectiveness

Q1. How would you rate the overall effectiveness of SPP's communication during the winter storm event?		
Respondent Type	**Average Rating**	**Equivalent Score**
Commissioners (10)	3.00	Effective
CAWG representatives (9)	2.88	Effective
Other (Texas OPUC, 1)	3.00	Effective
All Respondents	**2.95**	**Effective**

For individual categories of communication performance, the lowest ratings were given to the performance of SPP's members, and to assessments of how SPP and its members shared responsibility of communication with government and regulatory officials.

Some of the themes staff identified in open-ended responses were: a desire to improve advance notification, a need for more consistent communication from SPP and members, a need for clear sources of information and points of contact, a desire to improve the frequency of communication during an event, a need for more collaboration to reach overlapping audiences, and an opportunity to educate regulators, members and the public about these types of emergency events and how to respond.

SURVEY RESULTS BY QUESTION

The survey asked respondents to their agreement with the following statements below.

Q4: SPP's communication during the winter storm event was timely.

	Response percent	Response total
Strongly Agree	15%	3
Agree	65%	13
I don't know	5%	1
Disagree	15%	3
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q5: SPP communicated with appropriate frequency during the winter storm event.

	Response percent	Response total
Strongly Agree	10%	2
Agree	60%	12
I don't know	15%	3
Disagree	15%	3
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q6: Communication from SPP during the winter storm event was clear and understandable.

	Response percent	Response total
Strongly Agree	15%	3
Agree	70%	14
I don't know	5%	1
Disagree	10%	2
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q7: SPP effectively used a variety of communication methods (email, press releases, webinars, phone calls, website updates and social media) during the event.

	Response percent	Response total
Strongly Agree	20%	4
Agree	40%	8
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q8: SPP's leadership demonstrated necessary knowledge and expertise during the event, and were consistent in the delivery of their message.

	Response percent	Response total
Strongly Agree	25%	5
Agree	65%	13
I don't know	5%	1
Disagree	5%	1
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q9: SPP's communications clearly explained the actions stakeholders should take during the winter storm event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	50%	10
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	5%	1

Statistics based on **20** respondents;

Q10: SPP's communications during the event increased my trust in the credibility of SPP.

	Response percent	Response total
Strongly Agree	10%	2
Agree	45%	9
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	5%	1

Statistics based on **20** respondents;

Q11: SPP staff were available and willing to answer my questions during the event.

	Response percent	Response total
Strongly Agree	25%	5
Agree	45%	9
I don't know	30%	6
Disagree	0%	0
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q12: SPP's member organizations effectively communicated actions they were taking during the winter storm event.

	Response percent	Response total
Strongly Agree	15%	3
Agree	25%	5
I don't know	25%	5
Disagree	20%	4
Strongly Disagree	15%	3

Statistics based on **20** respondents;

Q13: SPP and its member organizations effectively shared responsibility for communicating with regulators during the event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	25%	5
I don't know	40%	8
Disagree	20%	4
Strongly Disagree	10%	2

Statistics based on **20** respondents;

Q14: SPP and its member organizations effectively shared responsibility for communicating with other elected officials during the event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	15%	3
I don't know	75%	15
Disagree	0%	0
Strongly Disagree	5%	1

Statistics based on **20** respondents;

APPENDIX F: COMMUNICATIONS SURVEY OF STAKEHOLDERS

SURVEY RESULTS BY QUESTION

Q1. Which of the following applies to you? (check all that apply)		
Respondent Type	**#**	**%**
Communications staff at an SPP member organization	31	20%
Government affairs staff at an SPP member organization	22	14%
Regulatory staff at an SPP member organization	17	11%
Operational staff at an SPP member organization	45	29%
Market staff at an organization participating in SPP's Integrated Marketplace	15	10%
Roster member of an SPP working group or committee	58	37%
Members Committee member of SPP	25	16%
SPP board member	7	5%
SPP staff	0	0%

Communications staff at an organization that is not a member of SPP	2	1%
Other role at an organization that is not a member of SPP	4	3%
Other role at an SPP member organization	16	10%
Other	8	5%
All Respondents (155 respondents)	**250**	**100%**

Q1. In what state(s) does your organization operate?		
State	**#**	**%**
Oklahoma / OK	53	14%
Kansas / KS	46	12%
Nebraska / NE	40	10%
Texas / TX	33	9%
Arkansas / AR (and one response of "AK" probably intended to be "AR")	27	7%
Missouri / MO	27	7%
South Dakota / SD	25	7%
New Mexico / NM	22	6%
Iowa / IA	21	5%
Louisiana / LA	17	4%
Minnesota / MN	17	4%
North Dakota / ND	17	4%
Montana / MT	12	3%
Wyoming / WY	13	3%
Colorado / CO	9	2%
Arizona / AZ	1	0%
California / CA	1	0%
Nevada / NV	1	0%
Utah / UT	1	0%
All Respondents (152 respondents)	**383**	**100%**

Q3: How would you rate the overall effectiveness of SPP's communication during the winter storm event? (154 responses)

	Response percent	Response total
Highly Effective	13.64%	21
Effective	66.23%	102
Neutral	16.23%	25
Ineffective	2.6%	4
Highly Ineffective	1.3%	2

The survey asked respondents to their agreement with the following statements.

Q4: SPP's communication during the winter storm event was timely. (155)

	Response percent	Response total
Strongly Agree	23.87%	37
Agree	58.71%	91
I don't know	7.1%	11
Disagree	9.03%	14
Strongly Disagree	1.29%	2

Q5: SPP communicated with appropriate frequency during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	26.45%	41
Agree	54.84%	85
I don't know	9.03%	14
Disagree	8.39%	13
Strongly Disagree	1.29%	2

Q6: Communication from SPP during the winter storm event was clear and understandable. (155)

	Response percent	Response total
Strongly Agree	24.52%	38
Agree	56.77%	88
I don't know	10.32%	16
Disagree	7.74%	12
Strongly Disagree	0.65%	1

Q7: SPP effectively used a variety of communication methods (email, press releases, webinars, phone calls, website updates and social media) during the event. (155)

	Response percent	Response total
Strongly Agree	21.94%	34
Agree	54.84%	85
I don't know	17.42%	27
Disagree	5.16%	8
Strongly Disagree	0.65%	1

Q8: SPP's communications clearly explained the actions stakeholders should take during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	18.07%	28
Agree	50.32%	78
I don't know	18.71%	29
Disagree	10.97%	17
Strongly Disagree	1.94%	3

Q9: SPP communications during the event increased my trust in the credibility of SPP. (155)

	Response percent	Response total
Strongly Agree	20%	31
Agree	50.32%	78
I don't know	24.52%	38
Disagree	3.87%	6
Strongly Disagree	1.29%	2

Q10: SPP's leadership demonstrated necessary knowledge and expertise during the event, and were consistent in the delivery of their message. (155)

	Response percent	Response total
Strongly Agree	29.03%	45
Agree	58.71%	91
I don't know	8.39%	13
Disagree	3.23%	5
Strongly Disagree	0.65%	1

Q11: SPP staff were available and willing to answer my questions during the event. (155)

	Response percent	Response total
Strongly Agree	30.32%	47
Agree	41.94%	65
I don't know	27.1%	42
Disagree	0%	0
Strongly Disagree	0.65%	1

Q12: SPP's member organizations effectively communicated actions they were taking during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	8.39%	13
Agree	46.45%	72
I don't know	32.9%	51
Disagree	10.97%	17
Strongly Disagree	1.29%	2

Q13: SPP and its member organizations effectively shared responsibility for communicating with regulators during the event. (22 Respondents – this question was only available to respondents who indicated they were government affairs or regulatory staff)

	Response percent	Response total
Strongly Agree	9.09%	2
Agree	45.46%	10
I don't know	31.82%	7
Disagree	13.64%	3
Strongly Disagree	0%	0

Q14: SPP and its member organizations effectively shared responsibility for communicating with other elected officials during the event. (22 Respondents – this question was only available to respondents who indicated they were government affairs or regulatory staff)

	Response percent	Response total
Strongly Agree	13.64%	3
Agree	31.82%	7
I don't know	27.27%	6
Disagree	27.27%	6
Strongly Disagree	0%	0

SOUTHWEST POWER POOL, INC.
Comprehensive Review Steering Committee

RECOMMENDATION TO THE SPP BOARD OF DIRECTORS
July 26, 2021

COMPREHENSIVE REVIEW STEERING COMMITTEE ROSTER

- **Lanny Nickell**: Chair (MOPC Staff Secretary and SPP Chief Operating Officer)
- **Larry Altenbaumer** (SPP Board of Directors Chair)
- **Barbara Sugg** (SPP President and Chief Executive Officer)
- **Betsy Beck:** Finance review co-lead (Members Committee representative and Enel Green Power North America Director of Organized Markets)
- **Denise Buffington**: Operations review lead (MOPC Chair and Evergy Director of Regulatory Affairs)
- **Keith Collin:**, Market monitoring review lead (SPP Market Monitoring Unit Executive Director)
- **Tom Dunn**: Finance review lead (Finance Committee Staff Secretary and SPP Chief Financial Officer)
- **Kristie Fiegen**: Regional State Committee review lead (Regional State Committee Chair and South Dakota Public Utilities Commissioner)
- **Joe Lang**: Operations review co-lead (Members Committee representative and Omaha Public Power District Director of Energy Regulatory Affairs)
- **Mike Ross**: Communications review lead (SPP Senior Vice President of Government Affairs and Public Relations)

BACKGROUND, GOALS AND DRIVERS

SPP experienced the most operationally challenging week in its 80-year history during Feb. 14-20, 2021. Due to record-low temperatures and high electricity use, the overall reliability of the bulk electric system was severely tested. SPP kept the lights on across its region with two short exceptions. SPP directed its transmission operators to curtail electricity use by about 1.5% for 50 minutes on Feb. 15 and by about 6.5% for approximately three hours on Feb. 16.

In a special meeting of the SPP Board of Directors and Members Committee on March 2, 2021, the board directed a comprehensive review of SPP's and its stakeholders' response to the February storm. Five teams were tasked with analyzing operational, financial, communications and other aspects of the event and identifying how SPP can be better prepared for future extreme threats to reliability.

ANALYSIS

The comprehensive review yielded seven key observations:

1. Generation unavailability, driven mostly by lack of fuel, was the largest contributing factor to the severity of the event's impacts. This root cause drives the need to develop policies that improve fuel assurance and resource adequacy. It highlights the need to further assess SPP's ability to reliably operate the system with more intermittent and fewer base-load resources. Better coordination and communication between the gas and electric industries could have significantly improved preparation activities.

2. Extremely high natural gas prices were the primary driver of record-high energy offers that exceeded the FERC-required offer cap of $1,000/megawatt-hour (MWh) for the first time in SPP's market history.

3. The rapid spike in SPP's market prices resulted in an immediate concern about liquidity of market participants and created an exponential increase in short-term credit exposure.

4. Relationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event. This emphasizes the value these relationships and robust transmission interconnections provide during emergency events and the opportunity to further strengthen them.

5. The SPP transmission system was highly congested at times during the event with limitations that prevented full use of generation available in certain locations. This issue exacerbated SPP's need to achieve balance between regional supply and demand through use of its load-shed procedures and raised questions about the appropriateness of regionally allocating load-shed responsibilities.

6. Early preparation, timely decisions and effective communication helped minimize the winter storm's impact on reliability. Early communication of a public conservation appeal contributed to reduced demand Feb. 15, reducing the amount of controlled service interruptions required. Effective communication of and prompt response to load-shed instructions likewise mitigated the risk of uncontrolled blackouts.

7. SPP's stakeholders indicated general satisfaction with SPP's emergency communications, information sharing and credibility related to the winter storm response, although some areas of improvement were identified, particularly in those related to end-use customer awareness.

REPORT'S RECOMMENDATIONS

The Comprehensive Review Steering Committee's report recommends 22 actions, policy changes and assessments categorized in three tiers according to urgency, importance, impact and other factors. Full implementation of many of these recommendations will be subject to further approvals as prescribed by SPP bylaws.

Recommendations are categorized according to a three-tier ranking system:

- **Tier 1:** Recommended actions, policies or assessments deemed necessary and urgent to avoid severe reliability, financial, operational, compliance or reputational risks. These recommendations are expected to address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts. Upon board approval, work associated with implementation of these recommendations shall be prioritized by the organization at the highest level and begin immediately.

- **Tier 2:** Recommended actions, policies or assessments deemed necessary to minimize the risk of severe reliability, financial, operational, compliance or reputational consequences associated with extreme system events. These recommendations may not address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts, but are important, are expected to significantly improve SPP's response to extreme system events in the future, and shall be treated as high-priority initiatives.

- **Tier 3:** Recommended actions, policies or assessments that would improve SPP's response, communications and public perception during extreme system events, but are not urgent.

Recommendations are categorized into three types:

Action: Development and/or implementation of a new process, requirement, protocol or other activity.

Policy: Development of principles to be used to guide subsequent development of requirements, protocols, and/or processes using the stakeholder process in accordance with bylaws, tariff provisions and applicable regulations.

Assessment: Performance of analysis that informs development of solutions through the stakeholder process.

The following charts summarize the recommendations by tier and category:

RECOMMENDATIONS BY TIER

	Tier 1	Tier 2	Tier 3
Fuel Assurance (FA)	2	1	-
Resource Planning & Availability (RPA)	2	-	-
Emergency Response Process & Planning (ERP)	-	3	-
Operator Tools, Communication and Processes (OTCP)	-	1	-
Seams Agreements (SEAMS)	-	1	-
Market Design (MKT)	-	3	-
Transmission Planning (TXP)	-	1	1
Credit (CR)	-	1	2
Communications (COMM)	-	2	2
22 TOTAL	4	13	5

SUMMARY OF RECOMMENDATIONS BY CATEGORY

	Action	Policy	Assessment
Fuel Assurance (FA)	-	2	1
Resource Planning & Availability (RPA)	-	1	1
Emergency Response Process & Planning (ERP)	1	1	1
Operator Tools, Communication and Processes (OTCP)	1	-	-
Seams Agreements (SEAMS)	1	-	-
Market Design (MKT)	1	2	-
Transmission Planning (TXP)	-	2	-
Credit (CR)	1	-	2
Communications (COMM)	3	-	1
22 TOTAL	8	8	6

There will be many opportunities for stakeholder feedback on all recommendations, including developing policies and assessing performance. Tier 2 & 3 recommendations will follow stakeholder processes including the Comprehensive Roadmap, Revision Request process, working group approvals, and MOPC and board approvals.

The “Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm” report represents the findings and recommended directional objectives generated during the comprehensive review, as consolidated, synthesized and summarized by SPP staff. The full report can be found in this meeting's background material on spp.org.

RECOMMENDATION

The Comprehensive Review Steering Committee and staff recommends the board of directors:

1. Accept its report, “A Comprehensive Review of Southwest Power Pool’s response to the February 2021 Winter Storm”
2. Direct work to begin immediately on recommendations that address root causes (Tier 1)
3. Direct organizational prioritization of work needed to address remaining recommendations.
4. Direct staff to provide quarterly updates on status of progress being made.
5. Direct staff to submit for board approval in October a project plan of activities needed to resolve the tier 1 recommendations.
6. Direct issuance of letters to all generator operators in the SPP region requiring them to inform SPP about their plans to have and maintain fuel necessary to assure availability of all generation treated as accredited capacity for the upcoming winter season.

SPP Southwest Power Pool

GI BACKLOG MITIGATION PLAN

BOARD OF DIRECTORS AND MEMBERS COMMITTEE MEETING JULY 27, 2021

Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool

SPPorg

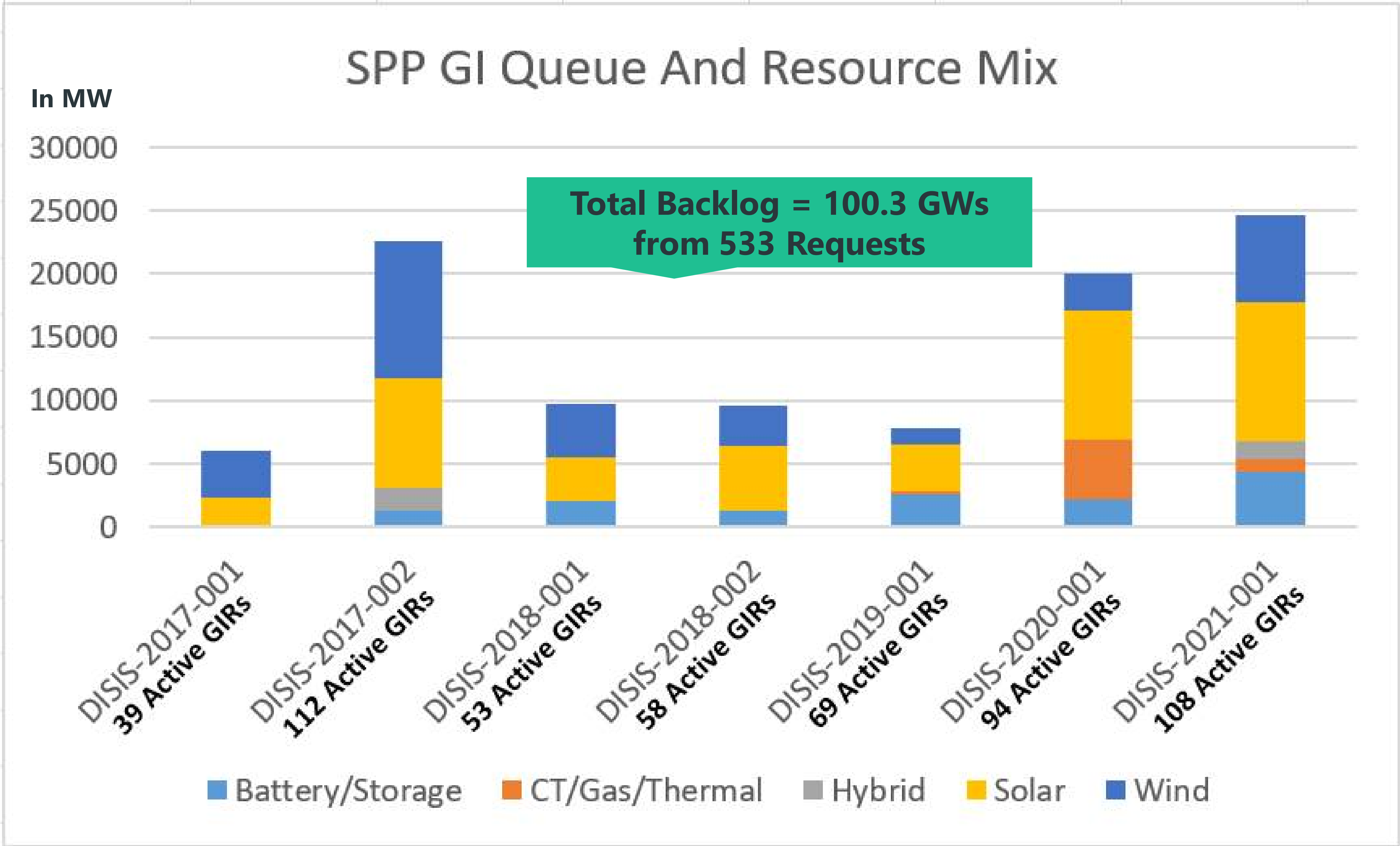
southwest-power-pool

BIG PICTURE: GOALS FOR TODAY

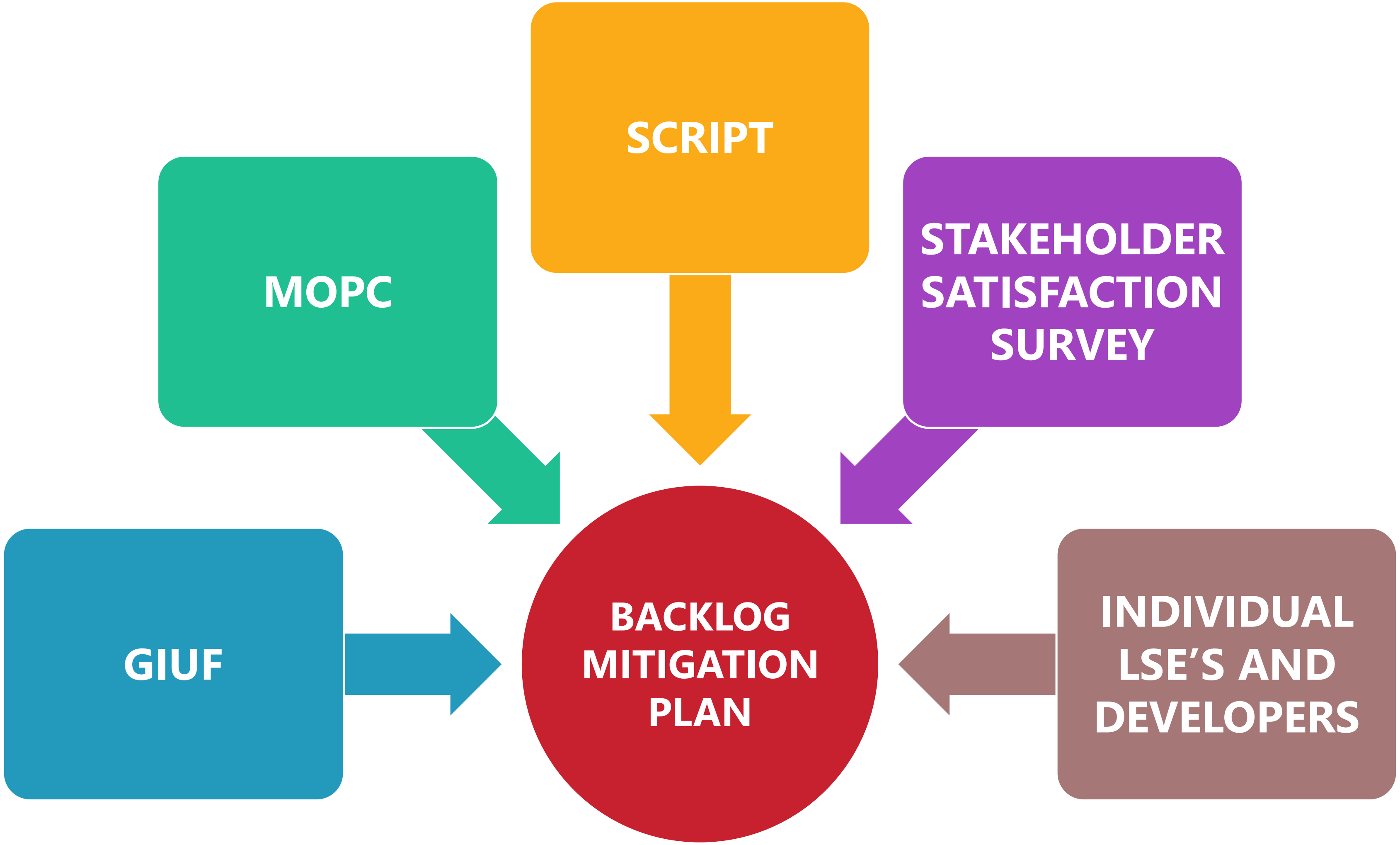
- Present final SCRIPT-approved Backlog Mitigation Plan
- Request SPP Board Approval of SCRIPT Recommendation

ACTIVE GI STUDY QUEUE

As of 6/17/2021



STAKEHOLDER ENGAGEMENT



BACKLOG MITIGATION STRATEGIES

1. Reduce restudies through development milestones

2. Increase financial commitments

3. Simplify and reduce study timelines

STRATEGY 1: REDUCE RESTUDIES THROUGH DEVELOPMENT MILESTONES

SCRIPT APPROVED UNANIMOUSLY

Strategy 1, Recommendation 1: *The SCRIPT recommends the adoption of new high voltage tie line and POI substation site control requirements, incorporating an "in lieu of" financial security option for the high voltage tie line site control requirement, and that "one or more" of the additional development milestones be required before the end of Decision Point 2.*

Strategy 1, Recommendation 2: *The SCRIPT recommends adopting progressively non-refundable DISIS study deposits.*

Strategy 1, Recommendation 3: *The SCRIPT recommends beginning the Interconnection Facilities Study for POI facilities as a part of Phase 2 of the three-phase process.*

Strategy 1, Recommendation 4: *The SCRIPT recommends eliminating Decision Point 3, beginning the GIA negotiation period at the beginning of Phase 3, and retaining the existing financial security refund eligibility provisions.*

MOPC APPROVED UNANIMOUSLY

STRATEGY 2: INCREASE FINANCIAL COMMITMENTS

SCRIPT APPROVED UNANIMOUSLY

Strategy 2, Recommendation 1: *The SCRIPT recommends increasing Financial Security 1 from the current $2,000/MW to $4,000/MW and making 25% of Financial Security 1 "at-risk" after the start of Phase 1.*

Strategy 2, Recommendation 2: *The SCRIPT recommends increasing the minimum amount of Financial Security 2 from the current $2,000/MW to $4,000/MW and making 25% of Financial Security 2 "at-risk" after the end of Decision Point 1.*

MOPC APPROVED UNANIMOUSLY

STRATEGY 3: SIMPLIFY AND REDUCE STUDY TIMELINES

SCRIPT APPROVED UNANIMOUSLY

Strategy 3, Recommendation 1: *The SCRIPT recommends SPP process backlogged DISIS clusters in parallel with each other by (i) starting Phase 1 of subsequent clusters after the end of DP1 of the prior cluster and (ii) starting Phase 2 of subsequent clusters after the end of DP2 of the prior cluster.*

Strategy 3, Recommendation 2: *The SCRIPT recommends SPP implement the TWG-approved process improvements and identify other process improvements to reduce the existing three-phase process timeline from approximately 485 days to approximately 365 days, or less, not counting the time required to conduct any necessary restudies.*

Strategy 3, Recommendation 3: *The SCRIPT recommends SPP seek approval from FERC to leave open (and not close) the DISIS-2022-001 Queue Cluster Window until after the completion of Phase 1 for DISIS-2021-001.*

Strategy 3, Recommendation 4: *The SCRIPT recommends SPP seek approval from FERC to combine clusters DISIS-2018-002 and DISIS-2019-001.*

MOPC APPROVED UNANIMOUSLY

BACKLOG CLEARING PROPOSAL NEXT STEPS

May 2021

- **5/28 SCRIPT – SCRIPT Unanimous Approval of Recommendations**

June 2021

- 6/2 – 2nd FERC Pre-Filing Meeting
- Began Drafting Revision Requests
- 6/30 GIUF Update

July 2021

- **7/12 Solicit MOPC endorsement of SCRIPT Recommendation**
- 7/22 – RTWG Overview of Policy and Impacted Tariff Sections
- 7/26 – Post RR to SPP.org
- **7/27 – Solicit Board Approval of SCRIPT Recommendation**
- 7/28 – GIUF Update

Aug-Oct, 2021

- 8/19 and 9/16: RTWG RR Review and Approval
- TBD – 3rd FERC Pre-Filing Meeting
- **10/11 – MOPC RR Review and Approval**

Nov 2021

- **11/1 – FERC Filing of Required Tariff Changes**

Once approved, SPP expects these enhancements to the three phase process to facilitate clearing the GI backlog by mid to late 2024

The SCRIPT recommends the SPP Board:

- approve the SCRIPT's recommendations and direct SPP staff to develop associated Revision Requests in coordination with the appropriate working groups as necessary to facilitate mitigation of the GI backlog.

SOUTHWEST POWER POOL, INC.
Strategic and Creative Re-engineering of Integrated Planning Team ("SCRIPT")

RECOMMENDATION TO THE BOARD OF DIRECTORS
July 27, 2021
Generator Interconnection Backlog Mitigation Plan

ORGANIZATIONAL ROSTER

The following persons are members of the SCRIPT:

Mark Crisson, SPP
Bronwen Bastone, SPP
Tom Christensen, Basin
Dennis Florom, LES
Christopher Jones, CUS
Brett Leopold, ITC
Richard Ross, AEP
David Mindham, EDP
Andrew French, KCC
Steve Gaw, APA
Bill Grant, SPS-Xcel
Dennis Grennan, NPRB
Joe Lang, OPPD
Usha Turner, OGE
Mike Wise, Golden Spread
Denise Buffington, Evergy

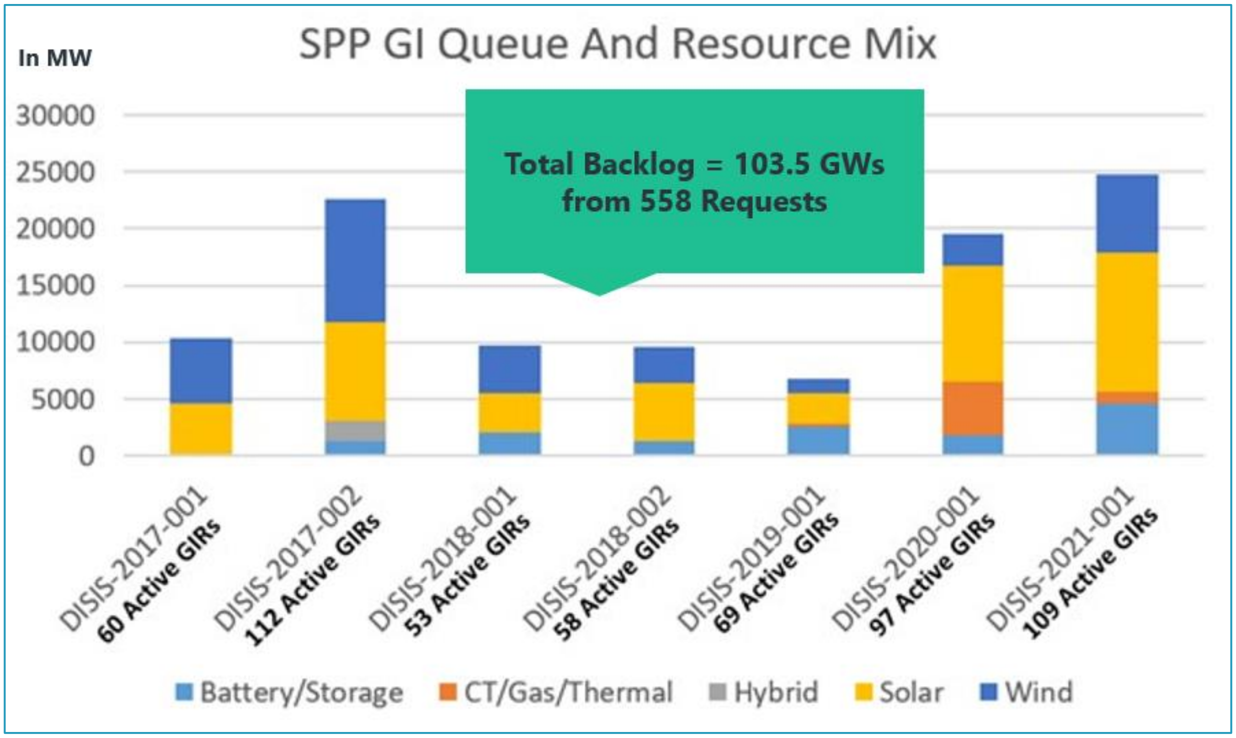
BACKGROUND

The SPP board of directors formed the Strategic & Creative Re-engineering of Integrated Planning Team ("SCRIPT") Aug. 31, 2020. The SCRIPT is responsible for strategically developing broad changes to SPP's transmission planning processes to better meet customer needs while resolving growing stakeholder concerns about the amount, nature and funding of continued transmission investment amid rapid industry changes. The SCRIPT is tasked with developing policy recommendations for SPP's transmission planning processes. This Recommendation Report supports the SCRIPT's Scope of Work by proposing policy modifications that will result in "improved responsiveness, efficiency and cost certainty of studies needed to provide customer-requested service."[1]

As of May 13, 2021, the Generator Interconnection ("GI") backlog of requests was comprised of seven Definitive Interconnection System Impact Study ("DISIS") clusters representing 558 individual GI requests and over 103,000 megawatts ("MW") of generation capacity. Reducing the

[1] The SCRIPT Scope Statement is located at: https://www.spp.org/documents/63768/20210106%20revised%20script%20scope%20statement.pdf

GI backlog was identified in SPP's 2021 Operating Plan as one of the top corporate and departmental objectives.[2]



When SPP implemented its legacy cluster study process was, it was experiencing significantly smaller GI queues. This legacy process often resulted in numerous restudies as a result of customer withdrawals and minimal financial commitments to remain in the studies. In 2019 SPP implemented a set of GI study and queue reforms known as the "Three-Phase" process that was designed to address the causes of the backlog in SPP's legacy cluster study process.

The new three-phase process was implemented beginning with the DISIS-2017-001 cluster. The three-phase process was designed to facilitate consistent, timely processing of *new* DISIS clusters. However, SPP does not believe that the existing three-phase process is sufficient to clear the existing backlog of GI requests without additional reforms. Without additional queue reforms, it is expected that it could take at least eight years or more for SPP to complete all current and future backlogged DISIS cluster studies This timeframe will be unacceptable to meet the needs of SPP's GI customers. SPP staff engaged stakeholders through the SCRIPT's Services sub-team, the Generation Interconnection Users Forum (GIUF) and ad hoc discussions with generation developers and various SPP members. This process has built general consensus for the need to address the GI backlog and for a package of additional GI queue reforms to specifically target reducing, and ultimately mitigating, the GI backlog. Over the last several

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[2] SPP's 2021 Operating Plan is located at: https://www.spp.org/documents/63478/2021%20operating%20plan%20(spp.org).pdf

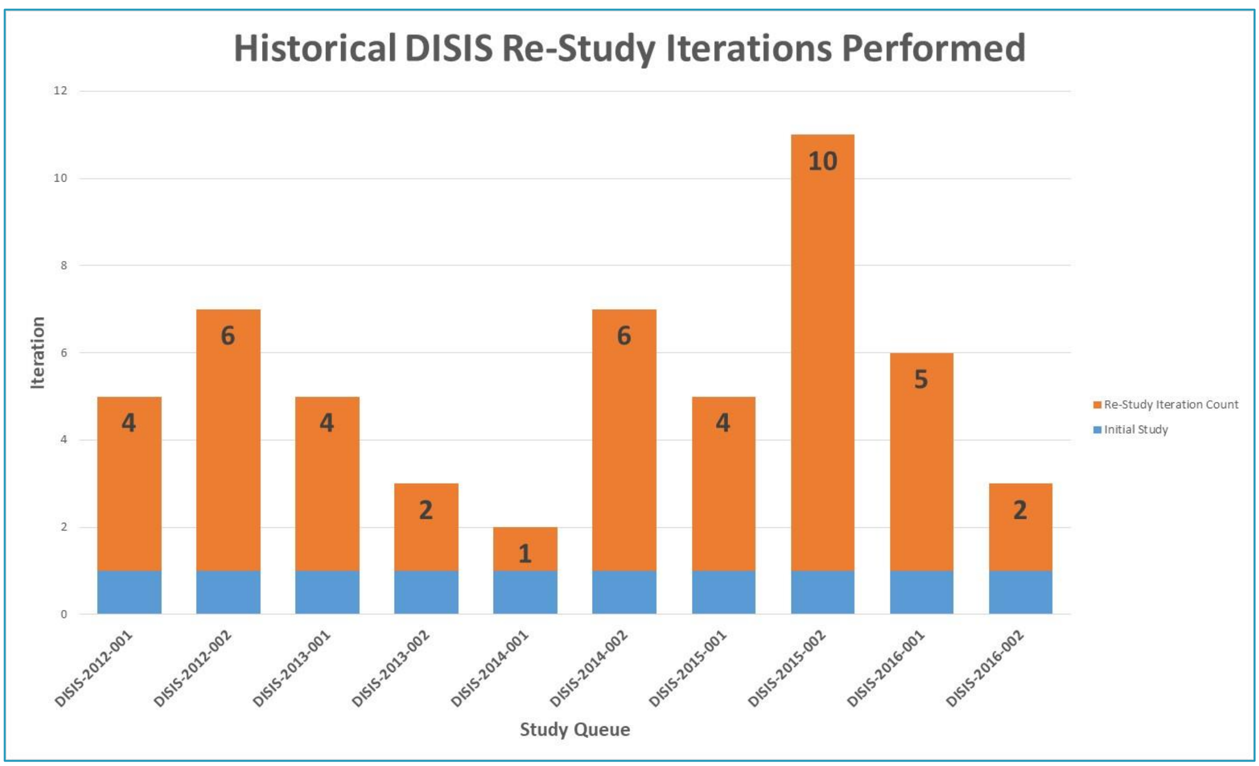
months, SPP has implemented numerous process improvements to the way it models and conducts GI studies, which will help in the overall goal of reducing study times. The reforms described in this Recommendation Report are in addition to these reforms and are based on three backlog mitigation strategies:

1. **Strategy 1: Reduce restudies through development milestones**
2. **Strategy 2: Increase financial commitments**
3. **Strategy 3: Simplify and reduce study timelines**

ANALYSIS

STRATEGY 1: REDUCE RESTUDIES THROUGH DEVELOPMENT MILESTONES

Frequent restudies under SPP's legacy cluster study process were a key reason for the existing GI backlog. Restudies were required when a GI customer withdrew an interconnection request during the study process. The restudy examined the effect of the withdrawn request on the remaining requests in the cluster. The restudy would often have a snowball effect, producing a result that remaining customers found unacceptable and leading to additional withdrawals and more restudies. The legacy cluster study process did not create enough incentives or penalties for customers to withdraw their requests until very late in the study.



The three-phase process implemented in 2019 attempted to address the issue of late stage withdrawals by requiring customers to make payments of financial security at each phase of the process. Under the new process, a portion of these financial securities would be "at risk" of forfeiture in the event a customer's withdrawal increases costs for remaining customers. While this financial security design is encouraging GI customers to make better decisions regarding the viability of their projects, it does not appear likely that the substantial amount of generation in the queue can be addressed with these changes alone. Additional reforms are needed to better ensure that the most viable interconnection projects remain in the latter stages of the study process.

1.1 Development Milestones: In addition to the financial securities, the existing Generator Interconnection Procedures ("GIP") contained in Section 11.3 of Attachment V of the Tariff require a demonstration that "one or more" development milestones have been satisfied, however these milestones are not currently required until 15 days after receipt of a final GIA.

Existing Development Milestones	
Contract for Fuel	Inclusion in State Resource Plan
Contract for Cooling Water	Designated Resource Qualification
Contract for Engineering, Procurement or Construction	Application for Air, Water or Land Use Permit
Contract for Sale of Energy or Capacity	

In addition to the existing development milestones, the SCRIPT determined that five (5) new development milestones should be added. Two of the new development milestones would be required, if applicable, and relate to additional site control requirements while three would be added to the list of existing development milestones in which "one or more" would be required to demonstrate sufficient project development.

New Development Milestones	
(Required) Site Control for Generator's High Voltage Tie **Line** (not including utility owned land)	Pre-Confirmed or Confirmed Long-Term Transmission Service Request ("TSR")
(Required) Site Control for New Point-of-Interconnection ("POI") Substations, if applicable (not including utility owned land)	Interim LGIA Accepted by the Federal Energy Regulatory Commission (FERC)
	Final Detailed Plant Design, and for Inverter-Based Resources, Submission of EMT Model

GI customers will be required to satisfy at least 50% of the new site control requirement for a generator's high voltage tie line before the start of Phase 1 of the customer's DISIS cluster. This requirement will increase to at least 75% by the conclusion of Decision Point 2.

Because a portion of the high voltage tie line site control is required very early in the three-phase process, GI customers will have the option of making additional payments of financial security "in lieu of" meeting the high voltage tie line site control requirement. The appropriate amount of "in lieu of" financial security will be further developed through the revision request process. Other transmission providers such as Midcontinent Independent System Operator (MISO) have previously adopted similar financial security payments "in lieu of" certain site control requirements.

If a GI customer elects to pay additional financial security "in lieu of" the high voltage tie line site control, the "in lieu of" security will be additive to the Financial Security 1, Financial Security 2 or Financial Security 3, as applicable, that is otherwise required in the three-phase process.

Similarly, the "in lieu of" security will be "at risk," as applicable, consistent with the amount of Financial Security 1, Financial Security 2, or Financial Security 3 that is "at risk." If at any point during the three-phase process the GI customer later satisfies the applicable high voltage tie line site control requirement, the "in lieu of" financial security will be refunded to the customer.

The additional site control requirement for new POI substations, if applicable, will be 100% and must be demonstrated by the conclusion of Decision Point 2. Because the POI substation site control is not required until later in the three-phase process, no "in lieu of" financial security option will be available.

The other three new development milestones will be added to the list of existing development milestones in which "one or more" would be required to demonstrate sufficient project development. To ensure that GI projects in the later stages of the study process are progressing in their development, "one or more" of these development milestones will be required by the end of Decision Point 2 in order for a customer to remain in the queue and progress to Phase 3 of the three-phase process.

GI projects that are more developed are less likely to withdraw their requests in the latter stages of the study process. Fewer late-stage withdrawals will result in fewer restudies required to complete each DISIS cluster which will facilitate mitigation of the GI backlog. In an effort to more efficiently address the GI backlog, the SCRIPT recommends that GI customers be required to demonstrate certain project development milestones earlier in the three-phase process.

Strategy 1, Recommendation 1: *The SCRIPT recommends the adoption of new high voltage tie line and POI substation site control requirements, incorporating an "in lieu of" financial security option for the high voltage tie line site control requirement, and that "one or more" of the additional development milestones be required before the end of Decision Point 2.*

In addition to adding new development milestones and advancing the demonstration of development milestones, the SCRIPT recommends several other enhancements to the existing three-phase process that will provide better incentives for customer decision-making, greater cost certainty for customers, and eliminate unnecessary steps in the study process.

<u>1.2 Non-Refundable DISIS Study Deposits</u>: The existing three-phase process requires each GI customer to post a study deposit that is based on the size of the generator requesting interconnection service. The study deposits are applied toward the costs of performing any studies applicable to the interconnection request, and the amount of unused study deposits are refundable to the extent the actual costs incurred are less than the study deposit. To better incentivize timely withdrawals that create fewer issues and discourage late-stage withdrawals, the SCRIPT recommends adopting progressively non-refundable[3] DISIS study deposits in accordance with the following schedule:

- 20% of initial study deposit non-refundable after the start of Phase 1
- 50% of initial study deposit non-refundable after the end of Decision Point 1
- 100% of initial study deposit non-refundable after the end of Decision Point 2

Other transmission providers, including California Independent System Operator (CAISO) and MISO, have a portion of their study deposits non-refundable or collect a non-refundable application fee upon entry into the GI queue.

Strategy 1, Recommendation 2: *The SCRIPT recommends adopting progressively non-refundable DISIS study deposits.*

<u>1.3 Perform Facilities Study for POI Facilities During Phase 2</u>: During the development of this GI Backlog Mitigation Plan, generation developers expressed concerns about the level of cost certainty they are able to get from the existing three-phase process. These concerns were heightened by the additional development milestone and financial security requirements that are being proposed to facilitate mitigation of the GI backlog.

To help address these concerns, the SCRIPT recommends beginning the Interconnection Facilities Study for POI facilities as a part of Phase 2 of the three-phase process. In the existing three-phase process, no part of the Interconnection Facilities Study is conducted until Phase 3 of the three-phase process. The SCRIPT believes this change is a reasonable compromise to provide increased cost certainty for generation projects who remain in the study process after Decision Point 1 because the extent of transmission upgrades needed at the POI are well understood by SPP, Transmission Owners, and the GI customer at this phase of the study. MISO

[3] Non-refundable refers to the portion of each customer's initial study deposit that would be retained by SPP to offset current study costs and reduce future study costs.

has adopted similar practices of beginning its Interconnection Facilities Study for POI facilities during Phase 2 of its study process.

Strategy 1, Recommendation 3: *The SCRIPT recommends beginning the Interconnection Facilities Study for POI facilities as a part of Phase 2 of the three-phase process.*

<u>1.4 Eliminate Decision Point 3 Window</u>: The existing three-phase process includes a period of fifteen (15) business days after SPP posts the results of the Interconnection Facilities Study in which GI customers may elect to proceed to negotiating a GIA. Additionally, the existing three-phase process provides that a customer may be eligible for a full refund of its Financial Security 1, Financial Security 2, and Financial Security 3 if the customer withdraws its request after Decision Point 2 and its allocated cost increases beyond certain criteria. This refund eligibility period is extended fifteen (15) business days after the posting of a revised Interconnection Facilities Study or a new or revised Affected System study which results in allocated costs that increase beyond the same criteria.

In an effort to further streamline the three-phase process, the SCRIPT recommends eliminating Decision Point 3 and beginning the GIA negotiation period in parallel with the Interconnection Facilities Study. This will reduce the time required to complete phase three and better facilitate the negotiation of GIAs. GI customers would maintain the refund eligibility period for financial securities contemplated in the existing three-phase process.

Strategy 1, Recommendation 4: *The SCRIPT recommends eliminating Decision Point 3, beginning the GIA negotiation period at the beginning of Phase 3, and retaining the existing financial security refund eligibility provisions.*

STRATEGY 2: INCREASE FINANCIAL COMMITMENTS

The existing three-phase process includes provisions for GI customers to provide financial securities at certain points in the study process. Those financial securities become "at risk" of forfeiture after certain decision points if the customer elects to withdraw their request and that withdrawal results in an adverse impact to other customers in the queue.

The SCRIPT recommends the amount of these financial securities be increased and the amount that is "at risk" be increased at certain points in the three-phase process in an effort to address the GI backlog, to reduce the risk of late-stage customer withdrawals, and to facilitate better GI customer decision making.

<u>2.1 Revise Financial Security 1</u>: In the existing three-phase process, Financial Security 1 is required from each GI customer before the close of the DISIS Queue Cluster Window and is currently not "at-risk" of forfeiture until after Decision Point 1. Financial Security 1 is currently $2,000/MW. A customer who withdraws their request before Decision Point 1 is eligible for a full refund of Financial Security 1. To address the GI backlog, the SCRIPT recommends increasing the size of Financial Security 1 and making a portion of Financial Security 1 "at risk" after the start of Phase 1 of the three-phase process.

Strategy 2, Recommendation 1: *The SCRIPT recommends increasing Financial Security 1 from the current $2,000/MW to $4,000/MW and making 25% of Financial Security 1 "at-risk" after the start of Phase 1.*

<u>2.2 Revise Financial Security 2</u>: In the existing three-phase process, Financial Security 2 is required to be paid by customers who elect to remain in the DISIS after Decision Point 1 and is currently not "at-risk" until after a customer elects to remain in the DISIS after Decision Point 2. Financial Security 2 is currently equal to the *greater* of:

a. Ten percent (10%) of the Financial Security 2 Cost Factor, less the amount of Financial Security 1 that was provided to enter DISIS Phase 1, or

b. $2,000/MW of the requested capacity advancing to DISIS Phase 2

A customer who withdraws their request before the end of Decision Point 2 is currently eligible for a full refund of their Financial Security 2. To address the GI backlog, the SCRIPT recommends increasing the *minimum* size of Financial Security 2 and making a portion of Financial Security 2 "at risk" after the end of Decision Point 1.

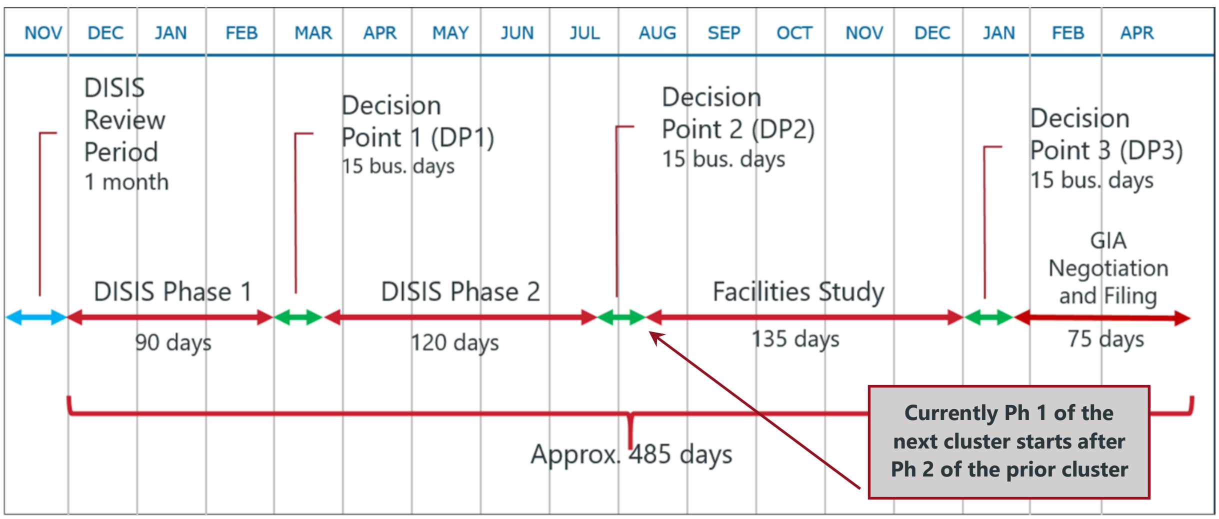
Strategy 2, Recommendation 2: *The SCRIPT recommends increasing the minimum amount of Financial Security 2 from the current $2,000/MW to $4,000/MW and making 25% of Financial Security 2 "at-risk" after the end of Decision Point 1.*

No other changes are proposed to the financial securities or for the determination of how financial securities are determined to be "at risk" of forfeiture due to withdrawal in accordance with Section 8.14 of Attachment V of the Tariff.

STRATEGY 3: SIMPLIFY AND REDUCE STUDY TIMELINES

Limiting the number of restudies required to complete a DISIS cluster through the reforms proposed in Strategy 1 and Strategy 2 is a key factor to addressing the GI backlog in a timely manner. In addition to limiting the number of restudies, the SCRIPT recommends four additional reforms to the three-phase process. These reforms are intended to simplify and reduce the overall study timelines to facilitate faster mitigation of the GI backlog.

The existing three-phase process takes approximately 485 days to complete each DISIS cluster from the beginning of Phase 1 to the execution and filing of GIAs, and this timeline is extended by at least 60 days for each required restudy that takes place when GI customers withdraw their requests at various stages of the process.



3.1 Parallel Processing: Currently, SPP only begins the study process of a new cluster after the prior cluster has completed Decision Point 2. While this practice helps to ensure the new cluster includes the best available information about the status of higher queued interconnection requests and their Network Upgrades, it delays the start of subsequent clusters and delays customers in those later clusters from getting information that could inform a decision of whether to proceed or withdraw their interconnection request. The SCRIPT recommends SPP process the backlogged clusters in parallel with each other to give customers their Phase 1 results earlier than under the existing study process.

Strategy 3, Recommendation 1: *The SCRIPT recommends SPP process backlogged DISIS clusters in parallel with each other by (i) starting Phase 1 of subsequent clusters after the end of DP1 of the prior cluster and (ii) starting Phase 2 of subsequent clusters after the end of DP2 of the prior cluster.*

3.2 Implement and Identify Improvements: The Transmission Working Group ("TWG") has recently approved recommendations to reduce the number of models required to conduct GI studies as well as to reduce the number of unique study groupings. SPP staff should take these recent process improvements and continue to pursue other study process improvements in an effort to reduce the overall length of time to conduct the three-phase process.

Strategy 3, Recommendation 2: *The SCRIPT recommends SPP implement the TWG-approved process improvements and identify other process improvements to reduce the existing three-phase process timeline from approximately 485 days to approximately 365 days, or less, not counting the time required to conduct any necessary restudies.*

3.3 Delay Cluster Closing: With the closing of the DISIS-2021-001 cluster window, the GI backlog includes seven (7) clusters representing 558 requests and over 103,000 MW of generation capacity. With the parallel cluster processing and reduced study timelines described in the previous recommendations, it will still take at least four years to process all backlogged clusters. The SCRIPT recommends additional actions be taken to keep the GI backlog from growing larger and to further reduce the number of DISIS clusters while preserving, as much as practicable, the queue priority of GI requests currently in the backlog. The SCRIPT recommends leaving open the next DISIS Queue Cluster Window while the new backlog mitigation plan is implemented. SPP took a similar approach when it transitioned to its revised Aggregate Transmission Service Study process.

Strategy 3, Recommendation 3: *The SCRIPT recommends SPP seek approval from FERC to leave open (and not close) the DISIS-2022-001 Queue Cluster Window until after the completion of Phase 1 for DISIS-2021-001.*

3.4 Combine Clusters: To further reduce the length of time required to clear the GI backlog and to reduce number of backlogged DISIS clusters, SPP should combine at least two clusters to create one larger cluster. SPP should seek to accomplish the combining of clusters while preserving, as much as practicable, the queue priority of GI requests currently in the backlog.

Of the seven (7) clusters comprising the GI backlog, DISIS-2018-002 and DISIS-2019-001 are the two smallest clusters, and they are adjacent to each other in queue priority. As such, it would be expected that combining DISIS-2018-002 and DISIS-2019-001 would be the least impactful to the queue priority and would facilitate a more efficient study process than seeking to combine larger clusters.

Strategy 3, Recommendation 4: *The SCRIPT recommends SPP seek approval from FERC to combine clusters DISIS-2018-002 and DISIS-2019-001.*

RECOMMENDATIONS

The SCRIPT recommends the SPP board of directors approve the following recommendations and direct SPP staff to develop associated Revision Requests in coordination with the appropriate working groups as necessary to facilitate mitigation of the GI backlog:

STRATEGY 1: REDUCE RESTUDIES THROUGH DEVELOPMENT MILESTONES

Strategy 1, Recommendation 1: *The SCRIPT recommends the adoption of new high voltage tie line and POI substation site control requirements, incorporating an "in lieu of" financial security option for the high voltage tie line site control requirement, and that "one or more" of the additional development milestones be required before the end of Decision Point 2.*

Strategy 1, Recommendation 2: *The SCRIPT recommends adopting progressively non-refundable DISIS study deposits.*

Strategy 1, Recommendation 3: *The SCRIPT recommends beginning the Interconnection Facilities Study for POI facilities as a part of Phase 2 of the three-phase process.*

Strategy 1, Recommendation 4: *The SCRIPT recommends eliminating Decision Point 3, beginning the GIA negotiation period at the beginning of Phase 3, and retaining the existing financial security refund eligibility provisions.*

STRATEGY 2: INCREASE FINANCIAL COMMITMENTS

Strategy 2, Recommendation 1: *The SCRIPT recommends increasing Financial Security 1 from the current $2,000/MW to $4,000/MW and making 25% of Financial Security 1 "at-risk" after the start of Phase 1.*

Strategy 2, Recommendation 2: *The SCRIPT recommends increasing the minimum amount of Financial Security 2 from the current $2,000/MW to $4,000/MW and making 25% of Financial Security 2 "at-risk" after the end of Decision Point 1.*

STRATEGY 3: SIMPLIFY AND REDUCE STUDY TIMELINES

Strategy 3, Recommendation 1: *The SCRIPT recommends SPP process backlogged DISIS clusters in parallel with each other by (i) starting Phase 1 of subsequent clusters after the end of DP1 of the prior cluster and (ii) starting Phase 2 of subsequent clusters after the end of DP2 of the prior cluster.*

Strategy 3, Recommendation 2: *The SCRIPT recommends SPP implement the TWG-approved process improvements and identify other process improvements to reduce the existing three-phase process timeline from approximately 485 days to approximately 365 days, or less, not counting the time required to conduct any necessary restudies.*

Strategy 3, Recommendation 3: *The SCRIPT recommends SPP seek approval from FERC to leave open (and not close) the DISIS-2022-001 Queue Cluster Window until after the completion of Phase 1 for DISIS-2021-001.*

Strategy 3, Recommendation 4: *The SCRIPT recommends SPP seek approval from FERC to combine clusters DISIS-2018-002 and DISIS-2019-001.*

Approved:	SCRIPT	May 28, 2021
	Passed Unopposed	
	MOPC	July 13, 2021
	Passed Unopposed	

Action Requested: Approve Recommendation

SOUTHWEST POWER POOL, INC.
Strategic Planning Committee

RECOMMENDATION TO THE BOARD OF DIRECTORS
07/26/2021

Recommendation for approval of New Member Terms & Conditions

ORGANIZATIONAL ROSTER

Members of the Strategic Planning Committee are:

BOARD AND SPP STAFF	TRANSMISSION OWNERS	TRANSMISSION USERS
Larry Altenbaumer, Board, Chair	Traci Bender, NPPD	Dennis Florom, LES
Mark Crisson, Board, Vice Chair	Tom Christensen, Basin	Andrew Lachowsky, AECC
Susan Certoma, Board	Bill Grant, SPS	David Mindham, EDP
Barbara Sugg, SPP	Kevin Noblett, Evergy	Matt Pawlowski, NextEra
Bruce Rew, SPP, Secretary	Richard Ross, AEP	Mike Wise, Golden Spread

BACKGROUND

Participants in Southwest Power Pool's Western Energy Imbalance Services (WEIS) have expressed interest in joining the SPP regional transmission organization (RTO) and as well as expansion of existing members placing certain facilities in the Western Interconnection under SPP's Open Access Transmission Tariff (tariff). This expansion opportunity in the Western Interconnection will help the prospective West parties reach renewable objectives, enhance reliability, lower wholesale electricity costs, and create new trading opportunities for existing members in the East.

SPP worked with the West parties interested in joining the RTO using the new member process. As part of this process, SPP's Strategic Planning Committee formed a Members Forum and the Regional State Committee formed a State Commission Forum to work with staff on new member integration. The Members Forum also formed a Steering Committee who worked closely with SPP staff throughout the entire review process. The Members Forum and its Direct Current (DC) Tie Task Force met multiple times throughout the first two quarters of 2021 to agree on necessary governing document and operational changes to integrate the West parties into the RTO. The DC Tie Task Force made significant progress on incorporating the DC ties into the SPP and will provide a fully vetted solution to the SPP board in October.

The comprehensive review of all SPP governing documents has resulted in a list of thirteen proposed terms and conditions necessary for the western expansion. The *Integrating Western Parties into SPP's RTO Terms and Conditions* document details the proposed modifications and conditions. Staff presented the terms and conditions to the State Commission Forum, Members Forum, and the Market & Operations Policy Committee for review and feedback. The Strategic Planning Committee recommends Board approval of the terms and conditions based on the following circumstances:

1. The terms and conditions approved will be valid through April 15, 2022.
2. The DC Tie terms and conditions will be submitted for SPC and Board approval in October of 2021. These additions will be part of the terms and conditions that will be valid through April 15, 2022. This approval is required before the parties will proceed with the execution of the Commitment Agreement.
3. West parties will execute a Commitment Agreement that will for new members commit to execution of a membership agreement, and for existing members commit to place certain western facilities under the SPP RTO control. The Commitment Agreement financially obligates the West parties to reimburse SPP should they not fulfill that commitment.
4. With West parties' commitments, SPP staff will finalize an implementation budget based on a March 1, 2024, implementation schedule and seek appropriate organizational approval of necessary expenditures.
5. Upon West parties' execution of the Commitment Agreement, SPP will modify, approve, and file governing documents to reflect the approve terms and conditions.

RECOMMENDATION

The Strategic Planning committee recommends Board approval of the *Integrating Western Parties into SPP's RTO Terms and Conditions* document for expansion of the SPP RTO into the Western Interconnection.

Approved:	Strategic Planning Committee (12 in favor, 2 abstentions (SPS, AEP))	07/14/21

INTEGRATING WESTERN PARTIES INTO SPP'S RTO

TERMS AND CONDITIONS

By: SPP Staff

Published on July 7, 2021

Version: 1.0

EXECUTIVE SUMMARY

Participants in Southwest Power Pool's Western Energy Imbalance Services (WEIS) have expressed interest in joining the SPP regional transmission organization (RTO) as well as expansion of existing members placing certain facilities in the Western Interconnection under SPP's Open Access Transmission Tariff (tariff). An independent study found that WEIS participants' membership in the SPP RTO will save $49 million annually: $24.2 million in new savings for current members and $25.1 million in savings for new western participants.

SPP works with prospective new members interested in joining the RTO using a new member process. As part of this process, SPP's Strategic Planning Committee formed a Members Forum and the Regional State Committee formed a State Commission Forum to work with staff on new member integration. The Members Forum and its Direct Current (DC) Tie Task Force met multiple times throughout the first two quarters of 2021 to agree on necessary governing document and operational changes to integrate the West parties into the RTO.

With the board of director's approval of this document, the identified terms and conditions will be valid until April 15, 2022 for new members and existing members adding Western Interconnection facilities to execute. If the West parties determine to financially commit to the integration, they will execute a commitment agreement before April 15, 2022 for an estimated go-live date of March 1, 2024. With these commitments, SPP will use its stakeholder process to finalize necessary governing document revisions for appropriate regulatory approvals.

Developing a framework to operate a single market across two interconnections presents several unique challenges, including:

- **DC ties:** The four DC ties being considered for addition to the SPP market are the strategic enablers for operating single a market in two asynchronous interconnections. A single market design that allows marginal energy cost divergence within the East and West market footprints is necessary for a dual interconnection market that does not break the fundamental price calculation principles used in the Integrated Marketplace. Since the DC ties are legacy assets, SPP needs to strike a balance in addressing compensation for market use within overall DC tie cost allocation. Special consideration is also required for allocating and managing auction revenue rights (ARR) and transmission congestion rights (TCR). The DC Tie Task Force continues to work toward solutions to these issues, with the goal of providing a fully vetted solution to the SPP board in October.

- **Zonal placement:** Some zones will cross interconnection boundaries, requiring special consideration regarding transmission cost allocation and revenue recovery.

- **Planning criteria:** SPP will employ a single FERC Order 1000 process for the entire market footprint while maintaining coordination with local planning groups.

- **Transmission Rates:** To ensure an efficient, one-market solution, SPP developed network and point-to-point transmission rates for crossing interconnection boundaries that allow for proper revenue recovery while eliminating pancaking.

- **Governance**: Several changes and additions will be made to recognize Eastern and Western Interconnection diversity.

The following policy revisions are necessary to integrate the West parties into the SPP RTO.

POLICY REVISIONS FOR BOARD OF DIRECTORS' APPROVAL

1. Modify the SPP Bylaws:
   - The organizational group selection process in Section 3.1 should consider Eastern and Western Interconnection diversity when selecting participants as named members
   - Expand the Strategic Planning Committee by two seats, one for Transmission Owning and one for Transmission Using members (as defined in Section 6.2).
2. Form a new, single Balancing Authority (West BA) encompassing the Western Area Colorado Missouri and Western Area Upper West Balancing Authorities.
3. Approve the West BA as a member of the Northwest Power Pool Reserve Sharing Group.
4. Expand SPP's current market by optimizing both BAs across the DC ties. The West parties will adopt the existing SPP Integrated Marketplace rules with only necessary modifications to incorporate a West BA into the existing market and to optimize the West DC ties.
5. If the East generation interconnection queue is experiencing a backlog at market launch, request a FERC waiver for West generation interconnection queue requests to be processed without waiting on the backlog to be cleared in the East queue.
6. Define transmission facilities added in the Western Interconnection under the tariff to be at or above 100 kV. Clarify language around DC tie facilities that does not alter the current application of Attachment AI regarding DC ties.
7. Utilize a single Order 1000 planning process for the SPP East and West footprints.
8. Perform the following studies:
   - LOLE study of the West consolidated footprint
   - Two additional sensitivity cases to identify possible AC system limitations in the East and West by modeling DC ties at their full capability.
9. Attachment AU is to be applicable only to the Transmission Owners in the Eastern Interconnection.

10. Extend the WAPA federal provisions and requirements to the Colorado River Storage Project (CRSP) Management Center (WAPA-CRSP) and Rocky Mountain Region (WAPA-RMR) and their respective zones CRSP zone and Loveland Area Projects (LAP) zone. There are similar provisions in the tariff for the Upper Great Plains Region (WAPA-UGP) and its Upper Missouri (UM) zone.

11. Manage the conversion from grandfathered service to SPP service using SPP's current process.

12. Follow the current zonal placement process.

13. Revise Point-to-Point and Network Transmission Service Rates:
    Due to the UM zone and LAP zone having facilities in both interconnections, some rates for point-to-point (PTP) and network transmission service and the associated revenue distribution will be based on the amount of annual transmission revenue requirement (ATRR) specific to the facilities in an interconnection, as detailed below.

- For network and PTP service sinking within a zone in the West, the zonal charges under Schedules 7, 8, 9, and 11 will be based on the zonal ATRR and load in the entire sink zone, including both the East and West portions of the UM and LAP zones.
- For Schedules 7 and 8, PTP service exiting the SPP footprint into other points of delivery in the Western Interconnection will be priced at a rate equal to the SPP West zonal weighted average price for facilities and load only in the West.
- For zonal Schedule 11, PTP service exiting the SPP footprint into other points of delivery in the Western Interconnection will be priced at a rate equal to the SPP West zonal weighted average price for facilities and load only in the West.
- For region-wide Schedule 11, service that sinks within a zone in the West, including the western portion of the UM and LAP zones, or exits the SPP region from the West, the rate will be based on the region-wide facilities and load only in the West.
- For region-wide Schedule 11, service that sinks within a zone in the East, including the eastern portion of the UM and LAP zones, or exits the SPP region from the East, the rate will be based on the region-wide facilities and load only in the East.

POLICY REVISIONS FOR REGIONAL STATE COMMITTEE'S REVIEW

1. If modified, approve the Supply Adequacy Working Group's recommendations on the planning reserve margin based on loss of load expectation (LOLE) study results for the West Balancing Authority.

Throughout the document, the red icon indicates a governing document change that must be approved by the SPP board of directors.
The green icon indicates a governing document change that must be approved by the Regional State Committee.

BACKGROUND & PROCESS

POTENTIAL WEST EXPANSION OF RTO

All the participants in SPP's WEIS signed letters indicating their interest in joining the SPP RTO as well as expansion of existing members placing certain facilities under the terms and conditions of SPP's Open Access Transmission Tariff. This expansion opportunity in the Western Interconnection will help western utilities and states reach renewable objectives, enhance reliability, lower wholesale electricity costs, and create new trading opportunities for existing members in the East.

An independent study by the Brattle Group found that WEIS participants' membership in the SPP RTO will save $49 million annually: $24.2 million in new savings for current East members and $25.1 million in savings for new West participants.

The following West parties are interested in joining the SPP RTO by placing some or all of their facilities in the Western Interconnection under the SPP tariff:

- Basin Electric Power Cooperative *
- Colorado Springs Utilities
- Deseret Power Electric Cooperative
- Municipal Energy Agency of Nebraska (MEAN) *
- Tri-State Generation and Transmission Association *
- Western Area Power Administration (WAPA)
    - Colorado River Storage Project Management Center (WAPA-CRSP)
    - Rocky Mountain Region (WAPA-RMR)
    - Upper Great Plains Region- (WAPA-UGP) *

** existing SPP RTO member*

In 2021, these interested West parties met weekly to discuss SPP membership or expanded participation in the SPP RTO and Integrated Marketplace in the Western Interconnection.

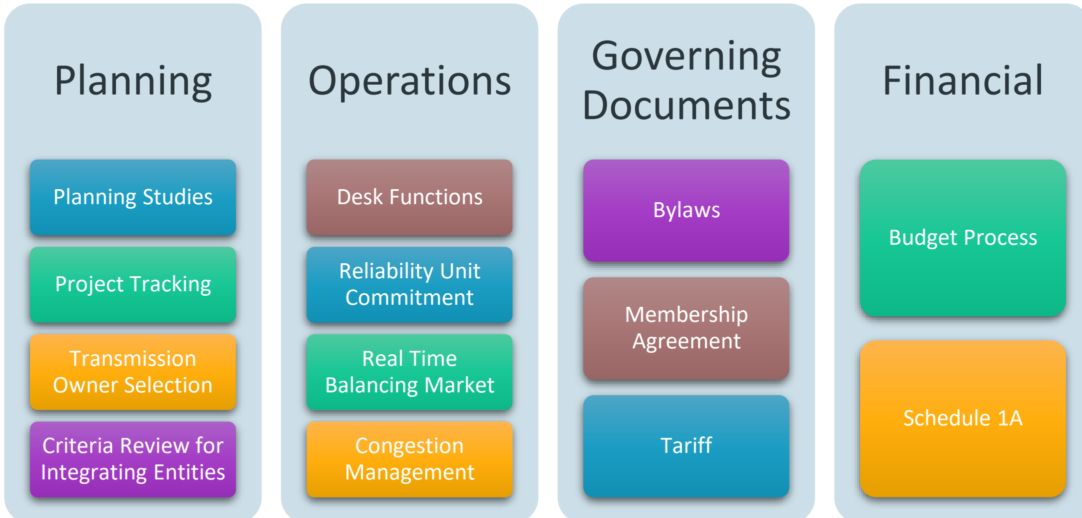
SPP will work with other entities that sign a letter indicating their interest in joining the SPP RTO in the West. Entities that are not participants of SPP's WEIS and are in a WEIS Balancing Authority Area can be part of the SPP RTO (for an estimated go-live date of March 1, 2024) if they sign the Commitment Agreement by April 15, 2022. With a sufficient commitment period, entities that are not participants in the SPP WEIS and not in the WEIS Balancing Authority Areas can be part of the SPP RTO as early as six months after the estimated March 1, 2024.

NEW MEMBER INTEGRATION PROCESS

SPP's Strategic Planning Committee oversees the new member integration process, and SPP staff act as the primary facilitator for the review. The SPC created a Members Forum and State Commission Forum in late 2020 to work with staff on new member integrations. The Members Forum is open to all SPP members. Twelve SPP members representing diverse backgrounds participate on the Members Forum Steering Committee:

MEMBERS FORUM MEMBER	COMPANY
Jim Jacoby, Lead	American Electric Power
Joe Lang, Lead	Omaha Public Power District
Dennis Florom	Lincoln Electric System
Steve Gaw	Advanced Power Alliance
Bill Grant	Xcel Energy
Brett Hooton	Gridliance High Plains
David Mindham	EDP Renewables North America
Robert Pick	Nebraska Public Power District
Jeff Riles	Google
Patrick Smith	Evergy
Al Tamimi	Sunflower Electric Power Corp
Mike Wise	Golden Spread Electric Cooperative

During January through June 2021, the Members Forum and its Steering Committee met regularly with SPP staff to discuss governing documents and operational changes needed to integrate the West parties into the SPP RTO. Discussion topics included:



The Members Forum created the Direct Current (DC) Tie Task Force to discuss the terms and conditions under which the four DC ties will be operated and managed. The task force has representatives from the Eastern and Western Interconnections and one representative from each DC tie owner. The group began meeting weekly in April 2021.

SPP staff is responsible for implementing the governing document changes that the Members Forum and West parties discussed. These changes are summarized in the following sections of this report.

The State Commission Forum is comprised of staff and commissioners from the Arkansas, Iowa, Kansas, Louisiana, Missouri, Nebraska, New Mexico, North Dakota, Oklahoma, Texas, and South Dakota state regulatory commissions. Some of these representatives also serve on SPP's Regional State Committee (RSC) and are Cost Allocation Working Group members. During January through June 2021, the forum received regular updates on the integration of West parties and outreach to western states' regulatory agencies. Any proposals from the West parties that impact the RSC's delegated areas of authority will be brought to the State Commission Forum for its review and consideration.

NEXT STEPS

Between May 2021 and April 2022, SPP will work with the prospective new members in the Western Interconnection to complete the appropriate reviews. SPP staff will support the necessary internal and public reviews required by the prospective members.

July 2021	April 2022	Oct. 2022	Q1 2023	March 1, 2024
West parties, board of directors and Regional State Committee approve terms and conditions policy level agreement	West parties execute commitment agreement Staff begins tariff modifications	SPP files tariff modifications with FERC	FERC approves tariff modifications	SPP expands RTO with new West members

POLICY AREAS

Board

GOVERNANCE

The West parties proposed two changes to the SPP bylaws:

1. The organizational group selection process in Section 3.1 should consider Eastern and Western Interconnection diversity when selecting participants as named members.
2. The Strategic Planning Committee (SPC), as defined in Section 6.2, would be expanded to include an additional participant in each of the Transmission Owning Member and Transmission Using Member sectors.

DC TIES

BACKGROUND

There are eight back-to-back DC ties in the United States and Canada, with a combined capacity of 1,470 MW, that connect the asynchronous Eastern and Western Interconnections. Seven of these back-to-back DC ties, with a combined capacity of 1,320 MW, are in the continental U.S. and connect SPP with the Western Interconnection. These DC ties provide a unique opportunity to develop the first organized market that spans two interconnections while expanding the current SPP RTO footprint.

Four of the DC ties in the United States are owned by current WEIS members and are the strategic enablers facilitating the westward expansion of the SPP RTO. Collectively, the WEIS DC tie owners will provide 640 MW of capacity for RTO operation.

The four DC ties are:

DC TIE	CAPACITY (MW)	OWNERSHIP	PERCENT OF CAPACITY
Miles City	200 E-W/150 W-E	WAPA-Upper Great Plains Basin (ownership-like rights)	WAPA-Upper Great Plains 60% Basin 40%
Rapid City*	200 bi-directional	Basin 65% Black Hills 35%	Basin 65% Black Hills 35%
Stegall	110 bi-directional	Tri-State	Basin 100%
Sidney	200 bi-directional	WAPA-Rocky Mountain Region	100%

**Only the Basin share of Rapid City will be available for market operation*

DC TIE TASK FORCE

The Members Forum established the DC Tie Task Force in April 2021 to discuss the terms and conditions under which the DC ties will be operated and managed. The group is addressing how to manage cost allocation of the legacy facilities, planning activities, point-to-point and network transmission rates, market utilization of the DC ties, and ARR/TCR allocations. Given the novel concept of operating a single market spanning two interconnections, with DC ties as the strategic enablers, the Members Forum wanted a balanced group to focus on these DC tie specific issues.

DC TIE TASK FORCE MEMBERS	
DC Tie Owners	
Basin Electric	Maria Tomac
Black Hills	Seth Nelson
Tri State	Mary Ann Zehr
WAPA-RMR	Raymond Vojdani
WAPA UGP	Lloyd Linke
Non-owning Western Member	
Deseret Power	Clay MacArthur
Eastern Membership Representatives	
AEP	Jim Jacoby
MEAN	Brad Hans
NPPD	Randy Lindstrom
WFEC	Brandon McCracken

The task force continues to evaluate options for DC tie use in the market. The taskforce has determined the following principles and concepts should be considered while working to develop an operations and cost recovery methodology:

- A single market solution allowing operation of the Integrated Marketplace in the Eastern and Western Interconnections
- The mechanism for recovering costs associated with the DC Ties from the market is to be roughly commensurate with the benefits.

- Congestion between East and West zones will be handled in a similar fashion to today's Integrated Marketplace.
- The market will utilize DC ties for maximum overall market benefit and dispatch them on a five-minute basis.
- The market design will not include a DC tie hurdle rate between interconnections for entities that utilize DC ties for transmission service.

The task force considered several ideas in pursuit of the ultimate solution:

- Full regional cost allocation of legacy and future DC tie assets via a regional load-based rate, including a phased approach to regional cost allocation. This option was not supported by the task force.
- Zonal cost allocation of legacy DC tie assets. DC tie rights holders would retain all risk and value of DC tie transmission rights of legacy assets by treating the DC ties as a simultaneous load and generation within the East and West zones. This option does not support a single market solution.
- Zonal cost allocation of legacy DC tie assets, regional cost allocation of future DC tie assets based on SPP planning criteria, and a market efficiency uplift (MEU) payment for market use of DC ties commensurate with market benefit up to the full ATRR of the DC tie facilities.

The task force is currently vetting the MEU option for SPP expansion into the west. FERC has indicated the following three policy principles in addressing storage as a transmission asset. Under the MEU option, these principles are deemed appropriate in this application of market-based revenue for compensation of DC tie facility costs.

1) **Avoid double-recovery of costs:** This would be achieved by providing for the crediting of market revenue against the ATRR as described below, but not permitting the Transmission Owner to retain an overcollection above the ATRR.
2) **Minimize adverse impacts on wholesale electric markets**: No bids or offers at the DC tie locations would be consistent with the way other entities have designed storage as a transmission-only asset.
3) **RTO/ISO independence**: This would be addressed through clearly distinguishing between the functional control of the RTO, including market dispatch, and the on-site operational control of the Transmission Owner.

OPERATIONS

OPERATING RESERVES

Operating Reserves will not be optimized across the DC ties, but rather within each Balancing Authority footprint.

BALANCING AUTHORITY

Due to the dynamics of operating a market in two asynchronous interconnections, SPP will form a new, single Balancing Authority (West BA) encompassing the current Western Area Colorado Missouri (WACM) and Western Area Upper West (WAUW) Balancing Authorities. NERC and WECC must certify the new West BA. SPP will request a waiver from the North American Energy Standards Board for tagging requirements between the two SPP BAs for market operation. If additional western Balancing Authorities join the SPP RTO, the West BA would be expanded to include new areas.

BALANCING AUTHORITY AGREEMENTS

The WACM and WAUW have existing BA agreements and available transmission capacity agreements and arrangements that need to be terminated. The BA functions need to be transferred to West BA. WACM and WAUW will no longer perform any BA functions after market go live.

RELIABILITY COORDINATOR

SPP acts as the Reliability Coordinator (West RC) under contract for the WEIS participants. The West RC will continue to provide RC services for the new RTO West footprint, as well as providing contract RC services for current West RC members that are not joining RTO West or participating in the WEIS. Upon joining the RTO, new members will receive RC services as members and the existing RC contract will be terminated.

RESERVE SHARING

The SPP West BA will be a member of the Northwest Power Pool Reserve Sharing Group (NWPP RSG). The current WAPA BAs (WACM and WAUW) are NWPP RSG members. The SPP West BA will develop a settlements process for transactions under the NWPP RSG.

Board

MARKET DESIGN

With the addition of the West parties, SPP will continue to operate with one Integrated Marketplace. The West parties will adopt the existing SPP Integrated Marketplace rules with only necessary modifications to incorporate a western Balancing Authority into the existing market and to optimize the DC ties within the expanded market footprint. SPP will manage the flow on the DC ties using a single, co-optimized market solution.

Due to the usage of a dual reference bus model, marginal energy cost convergence between the East and West portions of the Integrated Marketplace may not occur. Convergence of the locational marginal prices on either side of the DC ties may exist when the DC ties are unconstrained. When delivery limitations exist on the DC ties or the underlying transmission system, there will be potential for divergence between the settlement locations representing both sides of the DC tie.

The overall concept outlined here allows for SPP to accurately calculate the market pricing for a dual interconnection market without breaking the fundamental price calculation principles used in the Integrated Marketplace.

COMPLIANCE

PLANNING COORDINATOR TASKS

SPP will act as the Planning Coordinator for the RTO West parties. SPP will perform the responsibilities of the Planning Coordinator as defined in applicable NERC Standards and WECC Criteria (e.g., TPL-001-WECC-CRT-3.2). SPP will not act as the Transmission Planner or fulfill Transmission Planner responsibilities. SPP will not act as the Planning Coordinator or fulfill Planning Coordinator responsibilities for NERC registered entities that have not signed the SPP membership agreement or who do not have a separate agreement with SPP for Planning Coordinator services.

OPERATIONS TASKS

SPP currently acts as the Reliability Coordinator and is responsible for applicable NERC Standards and WECC Criteria associated with RC functions. SPP will begin operating as a single Balancing Authority in the Western Interconnection and will assume applicable NERC Standards and WECC Criteria associated with BA responsibilities. SPP will not act as the Transmission Operator or fulfill Transmission Operator responsibilities.

TRANSMISSION PLANNING

GENERATION INTERCONNECTION

The SPP tariff will have one defined generation interconnection (GI) process that will apply to both the Western and Eastern Interconnections. SPP is working on clearing the backlog for the East GI queue. SPP shall request a waiver from FERC for West GI queue requests to be processed should the East backlog to not be cleared at go-live. The timing of integrating the West parties and clearing the East backlog will determine if a waiver request is needed. If a waiver is needed, it will only be until the East queue is cleared; then SPP will have a single queue for the East and West. The queue position for the West interconnection will not be impacted by the East backlog clearing.

SPP has made changes to its GI process to address the cascading restudies caused by withdrawing projects late in the process that created the backlog. The study process changes have been in effect since July 1, 2019. SPP will utilize its current process to conduct GI studies for requests in both the Eastern and Western Interconnections. The SPP board of directors will consider recommendations for addressing the East GI backlog in July 2021.

TRANSMISSION DEFINITION

The agreed definition of which western facilities qualify to be transmission under the SPP Tariff differs slightly from the existing Attachment AI definition. Transmission facilities added in the West will include existing non-radial lines, substations, and associated facilities, operating at 100 kV or above, plus radial lines and associated facilities operated at or above 100 kV that serve two or more eligible customers that are not affiliates of each other. Clarifying language will be added around DC tie facilities that does not alter the current application of Attachment AI with regard to DC ties. These tariff changes will not be applicable to entities in the Eastern Interconnection for which the current tariff uses a standard voltage threshold of 60 kV. The current transmission definition including facilities “at or above 60 kV” will continue to be applicable to entities in the Eastern Interconnection.

LOCAL PLANNING COORDINATION

SPP’s regional planning process, specifically the Integrated Transmission Planning (ITP) assessment, will review locally planned upgrades resulting from a preexisting state or FERC-approved local planning process. As SPP performs the ITP it will evaluate whether a regional solution can solve needs resulting from both local and regional criteria in a more cost effective way than upgrades produced by the local planning process. SPP will also identify those local upgrades that are required to be constructed in coordination with a regional upgrade.

Board

RSC

RESOURCE ADEQUACY ANALYSIS

SPP will perform an LOLE study of the West footprint. The study will evaluate the possibility of adopting a minimum planning reserve margin for the Western Interconnection that is different from the currently approved planning reserve margin, with due consideration of the DC tie capacities. SPP will review the need for a separate analysis for accreditation of generation resources in the West region.

The RSC will be asked to consider the Supply Adequacy Working Group's recommendations on the planning reserve margin based on LOLE study results for the West BA.

TRANSMISSION FEASIBILITY

SPP will perform a transmission criteria review study comparable to the studies SPP performed to integrate both Nebraska and the Integrated System entities. The study will assess transmission system adequacy for meeting firm service obligations in the West footprint at the time of integration. Any transmission upgrades required from this study will be recovered from the responsible entity's customers and will not be eligible for regional cost allocation.

SPP will perform two additional sensitivity cases to identify possible limitations of the AC system in both East and West region by modeling the DC ties at their full capability in both directions. This study will be for informational purposes only.

Board

WESTERN AREA POWER ADMINISTRATION SPECIFIC PROVISIONS

The WAPA federal provisions and requirements will be extended to the Colorado River Storage Project Management Center (WAPA-CRSP) and the Rocky Mountain Region (WAPA-RMR) and their respective zones, as applicable. These are similar provisions in the current tariff for Upper Great Plains Region (WAPA-UGP) and its facilities in the UM zone, including the Federal Service Exemption. SPP will make revisions as necessary to maintain UGP's prior arrangements with the addition of WAPA-CRSP and WAPA-RMR, and include additions to address new WAPA requirements (primarily for WAPA-CRSP and WAPA-RMR) in the SPP West area. The WAPA federal provisions are summarized in Attachment 1.

The Federal Service Exemption, as found in Section 39.3 of the tariff, will apply to all project costs eligible for regional cost allocation.

WAPA is still engaged with SPP and discussing potential additional terms and conditions it may need for WAPA-CRSP.

ATTACHMENT AU

PROCEDURES FOR ALLOCATION OF REVENUES RESULTING FROM THE SETTLEMENT AGREEMENT IN COMMISSION DOCKET NOs. EL11-34-002, et al.

Attachment AU describes the distribution of revenue received from the Midcontinent Independent System Operator (MISO), under a settlement agreement, to SPP Transmission Owners based on estimated flow impacts resulting from energy transfers between MISO North and South subregions. Attachment AU will be clarified to state that such revenues are allocated only to Transmission Owners in the Eastern Interconnection.

EXISTING AGREEMENTS

GRANDFATHERED AGREEMENTS

SPP staff is working with the West parties to assist them with determining how and when grandfathered agreements can be converted to transmission service under the SPP tariff.

SPP staff will continue to work with West parties regarding other agreements (e.g., the Missouri Basin Power Project Agreement), as requested. SPP and the West parties continue to work toward solutions to converting existing rights to transmission service under the SPP tariff.

SEAMS AGREEMENTS

SPP has functional seams agreements with neighboring Transmission Service Providers, Reliability Coordinators, Balancing Authorities, Planning Coordinators, Market Operators, and Planning Regions in the Eastern Interconnection. SPP will work with integrating entities in the Western Interconnection to determine the level of coordination that may be required for each function. SPP will prioritize activities that are required by NERC and/or FERC. In many cases, existing Western processes and procedures may be sufficient. At the appropriate time, SPP will reach out to neighboring entities to establish new coordination processes that are identified as required.

For negotiations between SPP and their neighbors to develop seams agreements, SPP will utilize the process established under a Memorandum from the Seams Steering Committee to SPP.

ZONAL CONSTRUCT

The current zonal placement process will be followed in the Western Interconnection. Among the size criteria SPP applied in recent reviews is a comparison of the proposed ATRR to a minimum threshold based on a three-year average.

Board

POINT-TO-POINT TRANSMISSION SERVICE [1]

This proposal details the point-to-point (PTP) transmission service rate design and revenue distribution under the SPP tariff to include Western Interconnection transmission pricing zones (West) in the SPP RTO.

OUTLINE OF PROPOSAL

1) To the extent practicable, costs in the West are borne by load in the West and costs in SPP pricing zones in the Eastern Interconnection (East) are borne by load in the East.
2) All zones are wholly contained in either the East or the West with the exception of the UM and LAP zones, which will have facilities in both interconnections.
3) PTP transmission service revenue distribution is based on either the sink zone or the interconnection of exit from the SPP region.
   a) If PTP transmission service sinks in the East or exits to the Eastern Interconnection from SPP East, revenue stays with Transmission Owners in the East except for zonal revenues in the UM and LAP zones.
   b) If PTP transmission service sinks in SPP West or exits to the Western Interconnection from SPP West, revenue stays with Transmission Owners in the West except for zonal revenues in the UM and LAP zones.
4) In general, the PTP transmission service rates are calculated by dividing the applicable annual transmission revenue requirement (ATRR) by the corresponding load used for network load ratio share. However, SPP West PTP rate methodology may differ from SPP East methodology for transmission service that exits the SPP region.

POINT-TO-POINT TRANSMISSION SERVICE UNDER SCHEDULES 7 AND 8

RATES

Each zone's rates under Schedules 7 and 8 are based on the zonal Schedule 9 ATRR divided by zonal average coincident peak load. PTP transmission service exiting the SPP footprint into other points of delivery in the Western Interconnection will be priced at a rate equal to the SPP West zonal weighted average price. The weighting will be calculated as the total Schedule 9 ATRR in the West divided by the total load in the West that is used in determining zonal load ratio share

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[1] Tables are posted to SPP.org with more details on Network and PTP transmission service rates and revenue distribution.

under Schedule 9. This applies to transmission service originating in both the Eastern and Western Interconnections, regardless of whether or not that source is located in the SPP region.

PTP transmission service exiting the SPP footprint into other points of delivery in the Eastern Interconnection will be priced at a rate equal to the lowest rate of those SPP pricing zones in the East that are interconnected with the external point of delivery. This applies to transmission service originating in both the Eastern Interconnection and Western Interconnection, regardless of whether or not that source is located in the SPP region.

PTP transmission service sinking within a West zone will be priced at a rate equal to the sink zonal rate, including service that sinks in the portion of the UM or LAP zone in the West. The UM zonal rate and the LAP zonal rate will be calculated based on the zone's total Schedule 9 ATRR and load in both the East and West.

PTP transmission service sinking within an East zone will be priced at a rate equal to the sink zonal rate, including service that sinks in the portion of the UM or LAP zone in the East. The UM zonal rate and the LAP zonal rate will be calculated based on the zone's total Schedule 9 ATRR and load in both the East and West.

REVENUE DISTRIBUTION UNDER SCHEDULES 7 AND 8

For PTP transmission service that sinks in the West, the revenue will be distributed to Transmission Owners located in the West based 50% on Schedule 9 ATRR and 50% on MW-mile impacts. For PTP transmission service that does not source and sink in the same zone, the ATRR and MW-mile distribution considers all Transmission Owners in the West.

For PTP transmission service that sinks in the East, the revenue will be distributed to Transmission Owners located in the East based 50% on Schedule 9 ATRR and 50% on MW-mile impacts. For PTP transmission service that does not source and sink in the same zone, the ATRR and MW-mile distribution considers all Transmission Owners in the East.

In determining the Schedule 9 ATRR to be used for revenue distribution when the source and sink are not in the same zone, the UM and LAP zonal Transmission Owners must separate their ATRR between East and West such that only the eastern portion will be used for East revenue distribution and only the western portion will be used for West revenue distribution.

If the service sources and sinks in the same zone, including both the eastern and western sides of the UM and LAP zones, all Schedule 9 Transmission Owners in that source/sink zone will receive revenue from charges under Schedules 7 and 8 based 50% on Schedule 9 ATRR and 50% on MW-mile impacts.

POINT-TO-POINT TRANSMISSION SERVICE UNDER SCHEDULE 11

ZONAL RATES

PTP transmission service sinking within any zone in the SPP region will be priced at a rate equal to the sink's Schedule 11 zonal rate. The UM Schedule 11 zonal rate and the LAP Schedule 11 zonal rate will be calculated based on the zone's Schedule 11 zonal ATRR and load in both the East and West.

PTP transmission service exiting the SPP footprint into other points of delivery in the Western Interconnection will be priced at a rate equal to the SPP West zonal weighted average price. The weighting will be calculated as the total Schedule 11 zonal ATRR in the West, including the western portion of Schedule 11 zonal ATRR in the UM and LAP zones, divided by the total load in the West that is used in determining zonal load ratio share under Schedule 11.

PTP transmission service exiting the SPP footprint into other points of delivery in the Eastern Interconnection will be priced at a rate equal to the SPP East zonal weighted average price. The weighting will be calculated as the total Schedule 11 zonal ATRR in the East, including the eastern portion of the Schedule 11 zonal ATRR in the UM and LAP zones, divided by the total load in the East that is used in determining zonal load ratio share under Schedule 11. These rules apply to transmission service originating in both the Eastern Interconnection and Western Interconnection, regardless of whether or not that source is located in the SPP region.

ZONAL REVENUE DISTRIBUTION UNDER SCHEDULE 11

For PTP transmission service that sinks in an SPP zone in either the East or West, including both the eastern and western sides of the UM and LAP zones, the revenue will be distributed to the Transmission Owners with Schedule 11 zonal ATRR in the sink zone. Such distribution will be in proportion to their Schedule 11 zonal ATRR in that zone.

For PTP transmission service that exits the SPP region from the West, the revenue will be distributed to all Transmission Owners with Schedule 11 zonal ATRR in the West, in proportion to their western Schedule 11 zonal ATRR.

For PTP transmission service that exits the SPP region from the East, the revenue will be distributed to all Transmission Owners with Schedule 11 zonal ATRR in the East, in proportion to their eastern Schedule 11 zonal ATRR.

In determining the Schedule 11 zonal ATRR to be used for revenue distribution when the service exits the SPP region, the UM and LAP zonal Transmission Owners must separate their Schedule 11 zonal ATRR between East and West such that only the eastern portion will be used for East revenue distribution and only the western portion will be used for West revenue distribution.

REGION-WIDE RATES

PTP transmission service sinking within a West zone, including the western portion of the UM and LAP zones, or exiting the SPP footprint into other points of delivery in the Western Interconnection will be priced at the West region-wide rate, which will be calculated as the total Schedule 11 region-wide ATRR in the West divided by the total load in the West that is used in determining region-wide load ratio share under Schedule 11. The Schedule 11 region-wide ATRR and load will be calculated based on facilities and load located only in the West.

PTP transmission service sinking within an East zone, including the eastern portion of the UM and LAP zones, or exiting the SPP footprint into other points of delivery in the Eastern Interconnection will be priced at the East region-wide rate, which will be calculated as the total Schedule 11 region-wide ATRRs in the East divided by the total loads in the East that are used in determining region-wide load ratio shares under Schedule 11. PTP service sinking within the UM zone in the East will include only ATRR for facilities subject to rate recovery after the October 1, 2015, bright-line date. The Schedule 11 region-wide ATRRs and loads will be calculated based on facilities and loads located only in the East.

REGION-WIDE REVENUE DISTRIBUTION UNDER SCHEDULE 11

For PTP transmission service that sinks within a zone in the West, including the western portion of the UM and LAP zones, or exits the SPP region from the West, the revenue will be distributed to Transmission Owners with Schedule 11 region-wide ATRR in the West. Such distribution will be in proportion to their western Schedule 11 region-wide ATRR.

For PTP transmission service that sinks within a zone in the East, including the eastern portion of the UM and LAP zones, or exits the SPP region from the East, the revenue will be distributed to Transmission Owners with Schedule 11 region-wide ATRR in the East. Such distribution will be in proportion to their eastern Schedule 11 region-wide ATRR.

Board

NETWORK TRANSMISSION SERVICE

This proposal details the network integration (Network) transmission service rate design and revenue distribution under the SPP Tariff for inclusion of Western Interconnection transmission pricing zones (West) in the SPP RTO.

OUTLINE OF PROPOSAL

1) To the extent practicable, costs in the West will be borne by load in the West and costs in SPP pricing zones in the Eastern Interconnection (East) will be borne by load in the East.
2) All zones will be wholly contained in either the East or the West with the exception of the UM and LAP zones, which will have facilities in both interconnections.

3) Network transmission service charges and resulting revenue distribution will be based on either the sink zone in the SPP region or the delivery point external to the SPP region.
    c) If Network transmission service sinks in the East or exits to the Eastern Interconnection from SPP East, revenue stays with Transmission Owners in the East except for zonal revenues in the UM and LAP zones.
    d) If Network transmission service sinks in SPP West or exits to the Western Interconnection from SPP West, revenue stays with Transmission Owners in the West except for zonal revenues in the UM and LAP zones.
4) In general, the Network transmission service charges will be calculated by multiplying each customer's load ratio share by the applicable annual transmission revenue requirement (ATRR).

NETWORK TRANSMISSION SERVICE UNDER SCHEDULE 9

RATES

Each zone's charges under Schedule 9 will be based on the zonal Schedule 9 ATRR multiplied by each customer's zonal load ratio share. Network transmission service sinking within any zone in the SPP region will be charged based on the sink's Schedule 9 zonal rate, including service that sinks in the UM or LAP zones. The UM zonal rate and the LAP zonal rate will be calculated based on the zone's total Schedule 9 ATRR and load in both the East and West.

Network transmission service exiting the SPP region to load through the UM zone will be charged based on the UM zone's Schedule 9 rate.

Network transmission service exiting the SPP region from zones other than the UM zone will be charged based on the lowest Schedule 9 charge of the zones interconnected with the external point of delivery.

The above rules apply to transmission service originating from Network resources in either the Eastern Interconnection or Western Interconnection.

REVENUE DISTRIBUTION UNDER SCHEDULE 9

For Network transmission service that sinks in the SPP region, the Schedule 9 revenue will be distributed to Transmission Owners with Schedule 9 ATRR in the sink zone, in proportion to their Schedule 9 ATRRs. When the UM or LAP zone is the sink, the ATRR of both the eastern and western sides of the zone will be included in such distribution.

For Network transmission service that sinks outside the SPP region, the Schedule 9 revenue will be distributed to Transmission Owners with Schedule 9 ATRR in the zone that is used to determine Schedule 9 charges, in proportion to their Schedule 9 ATRRs.

NETWORK TRANSMISSION SERVICE UNDER SCHEDULE 11

ZONAL RATES

Network transmission service sinking within any zone in the SPP region will be charged based on the sink's Schedule 11 zonal ATRR and load. The UM Schedule 11 zonal rate and the LAP Schedule 11 zonal rate will be calculated based on the zone's Schedule 11 zonal ATRR and load in both the East and West.

Network transmission service exiting the SPP region will be charged based on the Schedule 11 zonal rate of the zone used for Schedule 9 charges to the same Network load. The UM zonal rate and the LAP zonal rate will be calculated based on the zone's total Schedule 11 zonal ATRR and load in both the East and West.

The above rules apply to transmission service originating from Network resources in either the Eastern Interconnection or Western Interconnection.

ZONAL REVENUE DISTRIBUTION UNDER SCHEDULE 11

For Network transmission service that sinks in an SPP zone in either the East or West, including both the eastern and western sides of the UM and LAP zones, the revenue will be distributed to the Transmission Owners with Schedule 11 zonal ATRR in the sink zone. Such distribution will be in proportion to their Schedule 11 zonal ATRR in that zone.

For Network transmission service that exits the SPP region, the revenue will be distributed to the Transmission Owners with Schedule 11 zonal ATRR in the zone used in determining the Schedule 11 zonal rate for that Network load, in proportion to their Schedule 11 zonal ATRR.

REGION-WIDE RATES

Network transmission service sinking within a West zone, including the western portion of the UM and LAP zones, or exiting the SPP region into other delivery points in the Western Interconnection, will be charged based on the West region-wide ATRR multiplied by the West region-wide load ratio share. The Schedule 11 region-wide ATRR and load will be calculated based on facilities and load located only in the West, including only the West portions of the UM and LAP zones.

Network transmission service sinking within an East zone, including the eastern portion of the UM and LAP zones, or exiting the SPP region into other delivery points in the Eastern Interconnection, will be charged based on the East region-wide ATRRs multiplied by the applicable East region-wide load ratio shares. Network service sinking within the UM zone in the East will include only ATRR for facilities subject to rate recovery in accordance with the October 1, 2015, bright-line date. The Schedule 11 region-wide ATRRs and loads will be calculated based on facilities and loads located only in the East, including only the East portions of the UM and LAP zones.

REGION-WIDE REVENUE DISTRIBUTION UNDER SCHEDULE 11

For Network transmission service that sinks within a zone in the West, including the western portion of the UM and LAP zones, or exits the SPP region from the West, the revenue will be distributed to Transmission Owners with Schedule 11 region-wide ATRR in the West. Such distribution will be in proportion to their western Schedule 11 region-wide ATRR.

For Network transmission service that sinks within a zone in the East, including the eastern portion of the UM and LAP zones, or exits the SPP region from the East, the revenue will be distributed to Transmission Owners with Schedule 11 region-wide ATRR in the East. Such distribution will be in proportion to their eastern Schedule 11 region-wide ATRR.

COMMITMENT AGREEMENT

Board

The RTO West parties who decide to move forward following their internal and stakeholder processes and approvals would execute a Commitment Agreement before April 15, 2022, for an estimated go live date of March 1, 2024. SPP would execute the Commitment Agreement. The Commitment Agreement would commit SPP to perform work and incur costs that will allow SPP to integrate the RTO West parties.

The agreement would commit the RTO West parties to perform work that will prepare them to integrate, and if they decide not to do so, they are obligated to pay SPP for costs as defined in the Commitment Agreement. SPP's costs will be identified, and allocated, in the agreement and each RTO West party will be responsible to pay SPP its share of those costs should it decide to not integrate.

The RTO West Parties and SPP are evaluating the specific terms and provisions of the Commitment Agreement. The details of the following concepts are being vetted and negotiated and are anticipated to be included in the final agreement:

- The agreement allows for changes to the integration costs to be made by SPP.
- Implementation delay costs
- The agreement can be terminated by any party without cause. If a West party terminates the agreement, that party pays SPP its share of SPP's costs.
- If SPP terminates the agreement, the West parties pay SPP 50% of SPP's costs.
- Other participants may be able to integrate at the same time as the West parties if SPP determines it is feasible and those parties execute a Commitment Agreement.
- The agreement terminates upon integration of the SPP West parties.
- The agreement will contain certain provisions applicable to the Western Area Power Administration and its participation in the integration.
- Integration costs for new member integration are recovered by SPP schedule 1-A rates on the membership effective date.

ATTACHMENT 1: SUMMARY OF WAPA FEDERAL PROVISIONS

1. Extend existing WAPA-UGP provisions.
    a. WAPA-CRSP and WAPA-RMR participation subject to existing WAPA-UGP Federal Laws and Regulations provisions: OATT Section 39.3(a) Subject to Acts of Congress; 39.3(b) Contingent upon Appropriations and Authorization; 39.3(c) Employment Practices; 39.3(i) Advance funding required for WAPA work under the Tariff, 39.3(J) Liability of WAPA is limited; 39.3(k) WAPA's rate review pursuant to its applicable regulations; and 39.3(l) WAPA not subject to State requirements in Section 39.1.
    b. Extend existing WAPA-UGP Co-supply provisions to WAPA-CRSP and WAPA-RMR (OATT Section 39.3(d))
    c. Extend existing WAPA-UGP Federal Service Exemption (FSE) to WAPA-CRSP and WAPA-RMR (OATT Section 39.3(e) and Attachment AE, Section 8.2.3)
        i. Exemption from Region-wide Charges internal to its Zone, or external to SPP (39.3(e)(i))
        ii. Exemption from Congestion and Marginal Loss Charges for WAPA-CRSP and WAPA-RMR deliveries from its Federal Resources to its Statutory Load Obligations, and provision of real power losses across its Zone (39.3(e)(ii))
    d. Extend existing WAPA-UGP limitations and coordination requirements with Corps of Engineers and/or Bureau of Reclamation projects to WAPA-CRSP and WAPA-RMR (OATT Section 39.3(f))
    e. Extend existing WAPA-UGP treatment of Federal Resources as Designated Resources to WAPA-CRSP and WAPA-RMR (OATT Section 39.3(g))
    f. Extend existing WAPA-UGP Federal requirements for interconnections to, or modifications to WAPA transmission facilities (including environmental requirements under NEPA) to WAPA-CRSP and WAPA-RMR (OATT Section 39.3(h))
    g. Extend existing WAPA-UGP limitations for no expansion of jurisdiction, waiver of defenses, liability for penalties, or inconsistent obligations to WAPA-CRSP and WAPA-RMR (OATT Section 39.3(m) and ByLaws Section 8.7.5)

2. New OATT Section 39.3(n) for all WAPA members (WAPA-CRSP, WAPA-RMR, and WAPA-UGP) to clarify the affiliate treatment of multiple WAPA divisions as SPP TO Members

under the tariff.

3. In the Membership Agreement, Section 4.2.2, add provision similar to WAPA-UGP's existing provision for WAPA-CRSP and/or WAPA-RMR to terminate SPP membership if other TOs withdraw from SPP or remove their facilities in the Western Interconnection portion of the RTO. In Membership Agreement Amendments A1.3, add revisions for WAPA divisions to reflect current WAPA participation by either WAPA-CRSP, WAPA-RMR, or WAPA-UGP on the Members Committee and the Federal Power Marketing Agency representative on Corporate Governance Committee.

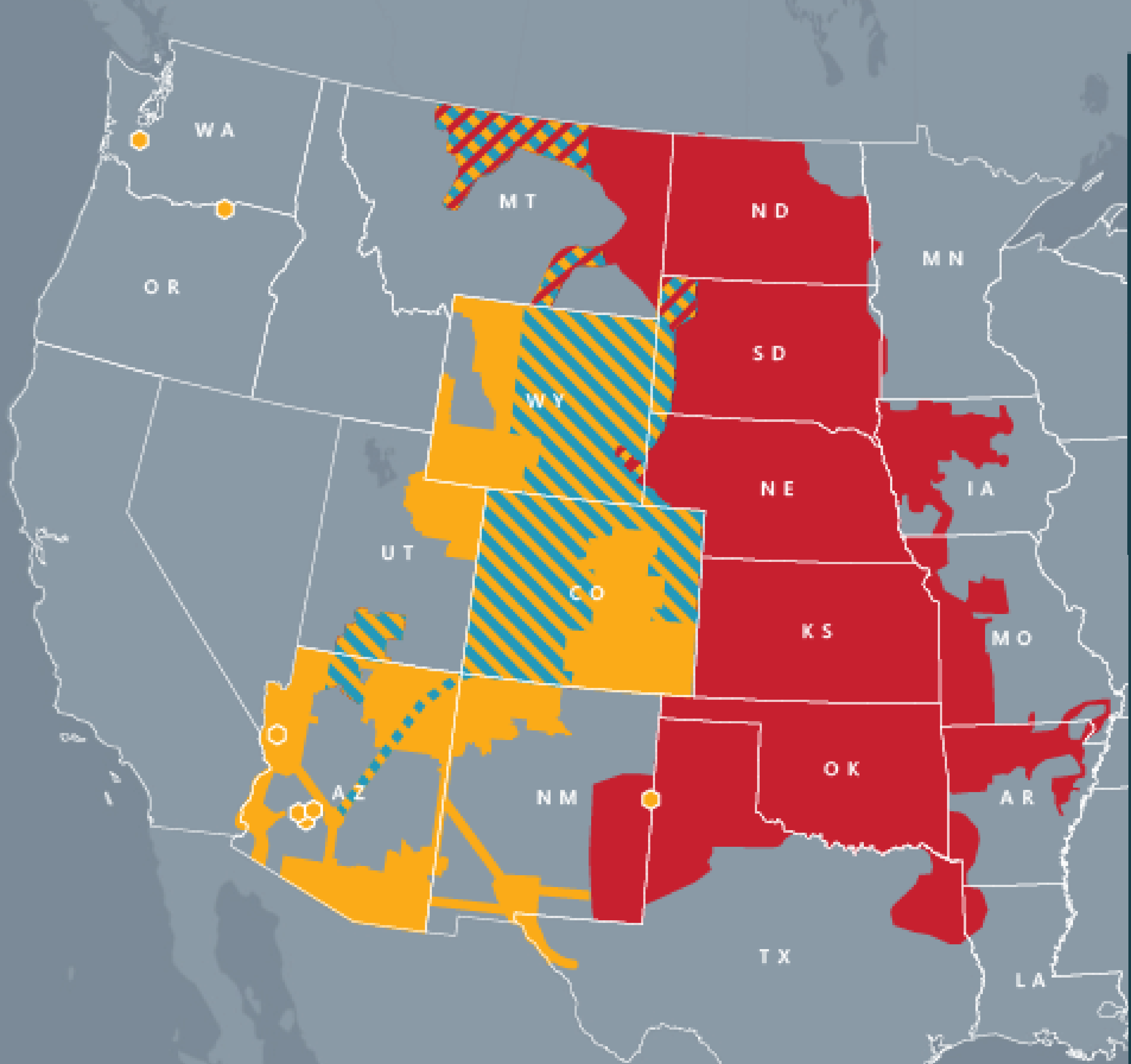
SPP Southwest Power Pool

SPP WEST EXPANSION TERMS AND CONDITIONS

BOARD OF DIRECTORS
JULY 26, 2021
BRUCE REW, PE
SENIOR VICE PRESIDENT, OPERATIONS

Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool



SPP Southwest Power Pool

- Regional Transmission Organization (RTO)
- Western Energy Imbalance Service (WEIS) and SPP RTO West
- Western Reliability Coordinator (RC)
- Generation-only Western RC participant

SPP West prospective members:

- Basin Electric Cooperative
- Tri-State G&T
- Deseret
- MEAN
- WAPA - Upper Great Plains
- WAPA - Rocky Mountain Region
- WAPA – Colorado River Storage Project
- Colorado Springs Utilities

SPP EXPANSION ACTIVITY TIMELINE

Jan. – June 2021
Technical Discussions

Feb. – May 2021
Governing Document and Tariff Review

June – July 2021
Terms and Conditions Completion - Members Forum

July 2021
Terms and Conditions Review - Review with MOPC

July/Oct – 2021
Terms and Conditions Policy Level Agreement - approved by Strategic Planning Committee and SPP Board of Directors

Apr. – 2022
Execution of **Membership Commitment Agreement** by the West Interested Parties

Apr. – 2022
SPP Staff begin preparing tariff modifications

Oct. - 2022
File Tariff Modifications with FERC to implement the SPP RTO on the West

Q1 - 2023
FERC approves tariff

Mar. 1, 2024
Launch SPP RTO in the West March 1, 2024

TERMS AND CONDITIONS DOCUMENT

- West Parties include both new members and expansion of facilities under RTO functional control for existing members
- Completed Terms and Conditions Document
  - SPP West parties in agreement with expansion T&C
  - Reviewed with State Commission Forum/Members Forum
  - Reviewed at the MOPC
  - DC Tie Policy work to be completed and approved in October
- Strategic Planning Committee approved July 14 (12 in favor, 2 abstentions)

TERMS AND CONDITIONS HIGHLIGHTS

- Goal of West Parties was to expand the RTO with minimal changes to existing organizational documents
- Thirteen Terms and Conditions Identified
- New Membership/expansion effective on market go-live date
- Key Points of Terms and Conditions
  - SPP organizational structure is not changing
  - One SPP Market across DC Ties
  - Transmission Process the same but impacts generally will stay within each interconnection

TERMS AND CONDITIONS HIGHLIGHTS

- Goal of West Parties was to expand the RTO with minimal changes to existing organizational documents
- Thirteen Terms and Conditions Identified
- Parties will have until April 15, 2022, to execute Commitment Agreement
  - New Membership/expansion effective on market go-live date
- Commitment Agreement execution by West Parties will begin RTO expansion project and commit parties to reimburse SPP should that not occur
- RTO Expansion scheduled for March 1, 2024

BOARD OF DIRECTORS POLICY PROPOSED CHANGES

1. Modify the SPP Bylaws:
   1. The organizational group selection process in Section 3.1 should consider Eastern and Western Interconnection diversity when selecting participants as named members
   2. Expand the Strategic Planning Committee by two seats, one for Transmission Owning and one for Transmission Using members (as defined in Section 6.2)
2. Form a new, single Balancing Authority (West BA) encompassing the Western Area Colorado Missouri and Western Area Upper West Balancing Authorities.
3. Approve the SPP West BA as a member of the Northwest Power Pool Reserve Sharing Group.
4. Expand SPP's current market by optimizing both BAs across the DC ties. The West parties will adopt the existing SPP Integrated Marketplace rules with only necessary modifications to incorporate a West BA into the existing market and to optimize the West DC ties.

BOARD OF DIRECTORS POLICY PROPOSED CHANGES

5. If the East generation interconnection queue is experiencing a backlog at market launch, request a FERC waiver for West generation interconnection queue requests to be processed without waiting on the backlog to be cleared in the East queue.

6. Define transmission facilities in the Western Interconnection under the tariff to be at or above 100 kV. Clarify language around DC tie facilities that do not alter the current application of Attachment AI with regard to DC ties.

7. Utilize a single Order 1000 planning process for the SPP East and West footprints.

8. **Perform the following studies:**
    1. LOLE study of the West consolidated footprint
    2. Two additional sensitivity cases to identify possible AC system limitations in the East and West by modeling DC ties at their full capability.

BOARD OF DIRECTORS POLICY PROPOSED CHANGES

9. Attachment AU is to be applicable only to the Transmission Owners in the Eastern Interconnection.
10. Extend the WAPA federal provisions and requirements to the Colorado River Storage Project (CRSP) Management Center (WAPA-CRSP) and Rocky Mountain Region (WAPA-RMR) and their respective Zones CRSP zone and Loveland Area Projects (LAP) zone. There are similar provisions in the tariff for the Upper Great Plains Region (WAPA-UGP) and its Upper Missouri (UM) zone.
11. Manage the conversion from grandfathered service to SPP service using SPP's current process.
12. Follow the current zonal placement process.

T&C BOARD POLICY PROPOSED CHANGES

13. Revise Point-to-Point and Network Transmission Service Rates:

Due to the UM zone and LAP zone having facilities in both interconnections, some rates for point-to-point (PTP) and network transmission service and the associated revenue distribution will be based on the amount of annual transmission revenue requirement (ATRR) specific to the facilities in an interconnection, as detailed below.

a) For network and PTP service sinking within a zone in the West, the zonal charges under Schedules 7, 8, 9, and 11 will be based on the zonal ATRR and load in the entire sink zone, including both the East and West portions of the UM and LAP zones.

b) For Schedules 7 and 8, PTP service exiting the SPP footprint into other points of delivery in the Western Interconnection will be priced at a rate equal to the SPP West zonal weighted average price for facilities and load only in the West.

c) For zonal Schedule 11, PTP exiting the SPP footprint into other points of delivery in the Western Interconnection will be priced at a rate equal to the SPP West zonal weighted average price for facilities and load only in the West.

d) For region-wide Schedule 11, service that sinks within a zone in the West, including the western portion of the UM and LAP zones, or exits the SPP region from the West, the rate will be based on the region-wide facilities and load only in the West.

e) For region-wide Schedule 11, service that sinks within a zone in the East, including the eastern portion of the UM and LAP zones, or exits the SPP region from the East, the rate will be based on the region-wide facilities and load only in the East.

BOARD OF DIRECTORS ACTION

- New Member Integration process requires Board approval of Terms and Conditions for RTO integration
- Approval is for Terms and Conditions to be offered for a limited time period through April 15, 2022
- West Parties are expected to join as a group
- Additional Approvals required
  - DC Tie policy conditions – October 2021
  - Implementation project expenditures FC/Board – May 2022
  - SPP Approval of Governing Document changes – October 2022
  - FERC Approval of Governing Document changes – Spring 2023
- RTO expansion scheduled for March 1, 2024

STRATEGIC PLANNING COMMITTEE RECOMMENDATION

- Strategic Planning Committee recommends approval of the *Integrating Western Parties into SPP's RTO Term and Conditions* document for expansion of the SPP RTO into the Western Interconnection.

QUESTIONS?

BRUCE REW

BRew@spp.org

A COMPREHENSIVE REVIEW OF SOUTHWEST POWER POOL'S RESPONSE TO THE FEBRUARY 2021 WINTER STORM

ANALYSIS AND RECOMMENDATIONS

By Southwest Power Pool

Published on July 19, 2021

Version 1.0

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EXECUTIVE SUMMARY

As a regional transmission organization (RTO) tasked with ensuring the reliable delivery of electricity to a 14-state region, Southwest Power Pool (SPP) experienced the most operationally challenging week in its 80-year history during Feb. 14-20, 2021. Many locations across the entire SPP service territory, from North Dakota to the Texas panhandle, experienced record-low temperatures for days on end. As consumers' use of electricity and natural gas increased in response to the cold, power producers simultaneously faced fuel-supply issues and equipment malfunctions, transmission system equipment approached unsafe operating limits, and the overall reliability of the bulk electric system was severely tested.

Despite the challenges of managing record wintertime electricity use, generation unavailability, fuel-supply issues, transmission congestion and historically high energy costs, SPP kept the lights on across its region throughout the winter storm, with two short exceptions. SPP directed its transmission operators (TOP) to curtail electricity use by temporarily interrupting their customers' electric service twice: once to lessen regional energy consumption by about 1.5% for 50 minutes Feb. 15 and again to lessen it by about 6.5% for a little more than three hours Feb. 16. Underscoring the historic significance of the February 2021 winter weather event, these marked the first times in the organization's history that SPP has called for regionwide curtailments.

In a special meeting of the SPP Board of Directors and Members Committee on March 2, 2021, the board directed a comprehensive review of SPP's and its stakeholders' response to the February storm. The review was organized to analyze operational, financial, communications and other aspects of the events of Feb. 14-20, and to identify how the organization can learn, adapt and be better prepared for future extreme threats to reliability.

Five teams were tasked with evaluating a multitude of factors related to the event, and a steering committee was formed[1]. The five teams' areas of focus, the stakeholder groups and other audiences who primarily contributed input to their reviews, and team leaders are summarized in the table below.

[1] The Comprehensive Review Steering Committee comprised each teams' leader plus board chair Larry Altenbaumer, Members Committee representatives Joe Lang (Omaha Public Power District) and Betsy Beck (Enel Green Power North America), SPP President and CEO Barbara Sugg, and SPP COO Lanny Nickell, who chaired the committee.

Table 1: Comprehensive review teams' focus areas, representation and leadership

REVIEW TEAM	FOCUS AREAS	STAKEHOLDER GROUPS REPRESENTED	TEAM LEAD
Operations	Operational reliability Balancing authority Market performance Resource adequacy Transmission planning	Markets and Operations Policy Committee, Operating Reliability Working Group, Market Working Group, Transmission Working Group, and Supply Adequacy Working Group	**Denise Buffington** MOPC chair, Evergy director of regulatory affairs **Joe Lang** Members Committee representative, Omaha Public Power District director of energy regulatory affairs
Finance	Settlement and credit issues	Finance Committee, Settlements User Forum, Credit Practices Working Group	**Tom Dunn** Finance Committee staff secretary, SPP chief financial officer **Betsy Beck** Members Committee representative, Enel Green Power North America director, organized markets
Communications	Protocols and coordination related to operational, stakeholder, governmental and public communications	Communications representatives from stakeholder organizations	**Mike Ross** SPP senior vice president of government affairs and public relations
Regional State Committee	Resource adequacy and cost allocation	Regional State Committee, Cost Allocation Working Group	**Commissioner Kristie Fiegen** Regional State Committee president, South Dakota Public Utilities commissioner
Market Monitoring Unit	Actual gas costs for settlements purposes Market behavior and rules issues How the markets worked overall	Independent review	**Keith Collins** SPP MMU executive director

This report represents the findings and recommended directional objectives generated during the comprehensive review, as consolidated, synthesized and summarized by SPP staff. A report produced by SPP's independent Market Monitoring Unit (MMU) is published separately and is available on SPP.org along with other MMU reports.

KEY OBSERVATIONS

The comprehensive review yielded seven key observations regarding the root causes of the winter storm's impact, SPP's response and its preparedness to respond to future reliability events.

1. The unavailability of generation, driven mostly by lack of fuel, was the largest contributing factor to the severity of the winter weather event's impacts[2], which was exacerbated by record wintertime energy consumption[3] and a rapid reduction of energy imports[4].

   This root cause drives the need to develop policies that improve fuel assurance and resource adequacy and highlights the need to further assess SPP's ability to reliably operate the system with more intermittent and fewer base-load resources. Better coordination and communication between the gas and electric industries could have significantly improved preparation activities.

2. Extremely high natural gas prices were the primary driver of record-high energy offers that exceeded the FERC-required offer cap of $1,000/megawatt-hour (MWh) for the first time in SPP's market history. On Feb. 15, SPP's market price reached an all-time high of $4,274.96/MWh in the day-ahead market. By comparison, the average price of energy in SPP's day-ahead market for the entire year of 2020 was $17.69/MWh. Natural gas markets are not subject to price or offer caps, while electricity markets like SPP's are.

3. The rapid spike in SPP's market prices resulted in an immediate concern about liquidity of market participants and created an exponential increase in short-term credit exposure.[5]

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[2] Up to approx. 59,000 MW of generating nameplate capacity in SPP was unavailable to meet demand during the week of the event. When generation was most needed on Feb. 16, about 30,000 MW of generating capacity was unavailable due to forced outages. The largest single cause of these forced generation outages was attributed to fuel-supply issues, causing nearly 47% of the outages and affecting over 13,000 MW of gas generation.
[3] SPP set a new winter peak load of 43,661 MW the morning of Feb. 15 and likely would have reached a wintertime peak of 47,000 MW if not for conservation and curtailments.
[4] Reductions in imports were due to transmission congestion and tightening supply conditions in neighboring areas. Between 2,000 and 2,500 MW of imports were quickly reduced on both Feb. 15 and 16, contributing to SPP's need to shed load each day.
[5] SPP sought and received a waiver from FERC extending the cure period for load serving entities to satisfy calls for financial security.

4. Relationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event, with net amounts exceeding 6,000 megawatts (MW) at times. This emphasizes the value these relationships and robust transmission interconnections provide during emergency events and the opportunity to further strengthen them.

5. The SPP transmission system was highly congested at times during the event with limitations that prevented full use of generation available in certain locations.[6] This issue exacerbated SPP's need to achieve balance between regional supply and demand through use of its load-shed procedures and raised questions about the appropriateness of regionally allocating load-shed responsibilities.

6. Early preparation, timely decisions and effective communication helped minimize the winter storm's impact on reliability. Early communication of a public appeal for conservation contributed to reduced demand Feb. 15, reducing the amount of controlled service interruptions required. Effective communication of and prompt response to load-shed instructions likewise mitigated the risk of uncontrolled blackouts.

7. SPP's stakeholders indicated general satisfaction with SPP's emergency communications, information sharing and credibility related to the winter storm response, although some areas of improvement were identified, particularly in those related to end-use customer awareness.

More on these key observations and related issues can be found in the following sections provided later in this report:

- Analysis of Operations and Market Performance
- Analysis of Finance, Settlements and Credit
- Analysis of Communications

RECOMMENDATIONS

Throughout the comprehensive review, SPP staff and stakeholders evaluated hundreds of potential process changes, system enhancements, new and amended policies, further assessments, and other potential solutions meant either to address the root causes of the February 2021 event's impact on the SPP system or to better enable SPP and its stakeholders to respond to future extreme system events. Ultimately, this report recommends 22 actions, policy changes and assessments categorized in three tiers[7] according to urgency, importance, impact

[6] SPP experienced 54 transmission constraints at the time load shedding began Feb. 16 that resulted in nearly 1,900 MW of generation being reduced to maintain reliable energy flows on those facilities.
[7] Of these 22 recommended objectives, four are tier 1, thirteen are tier 2 and five are tier 3.

and other factors. Full implementation of many of these recommendations will be subject to further approvals as prescribed by SPP bylaws.

Recommendations are categorized according to a three-tier ranking system defined as follows:

- **Tier 1:** Recommended actions, policies or assessments deemed necessary and urgent to avoid severe reliability, financial, operational, compliance or reputational risks.

  These recommendations are expected to address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts.

  Upon board approval, work associated with implementation of these recommendations shall be prioritized by the organization at the highest level and begin immediately.

- **Tier 2:** Recommended actions, policies or assessments deemed necessary to minimize the risk of severe reliability, financial, operational, compliance or reputational consequences associated with extreme system events.

  These recommendations may not address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts, but are important, are expected to significantly improve SPP's response to extreme system events in the future, and shall be treated as high-priority initiatives.

- **Tier 3:** Recommended actions, policies or assessments that would improve SPP's response, communications and public perception during extreme system events, but are not urgent.

Recommendations are also categorized into one of three possible types, defined as follows:

- **Action**: Development and/or implementation of a new process, requirement, protocol or other activity.

- **Policy**: Development of principles to be used to guide subsequent development of requirements, protocols, and/or processes using the stakeholder process in accordance with bylaws, tariff provisions and applicable regulations.

- **Assessment**: Performance of analysis that informs development of solutions through the stakeholder process.

FUEL ASSURANCE

Table 2: Summary of recommendations to the board related to fuel assurance

#	TIER	CATEGORY	RECOMMENDATION
FA 1	1	Policy	Develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region.
FA 2	1	Assessment	Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events.
FA 3	2	Policy	Develop policies to improve gas-electric coordination that better inform and enable improved emergency response.

RESOURCE PLANNING AND AVAILABILITY

Table 3: Summary of recommendations to the board related to resource planning and availability

#	TIER	CATEGORY	RECOMMENDATION
RPA 1	1	Assessment	Perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix.[8]
RPA 2	1	Policy	Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives[9] that ensure sufficient resources will be available during normal and extreme conditions.

[8] The Holistic Integrated Tariff Team's (HITT) recommendation R1 should be considered when addressing RPA 1.
[9] HITT recommendation R2 should be considered when addressing this part of RPA 2.

EMERGENCY RESPONSE PROCESSES AND PLANNING

Table 4: Summary of recommendations to the board related to emergency response processes and planning

#	TIER	CATEGORY	RECOMMENDATION
ERP 1	2	Assessment	Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations.
ERP 2	2	Action	Implement improvements to load-shed processes to be developed by the Operating Reliability Working Group (ORWG), such as: • Utilize real-time load values when determining load-shed ratio shares. • Train and drill on multiple overlapping load-shed instructions. • Perform a detailed review of models used to determine load-shed ratio shares. • Develop and document procedures and processes to address the timing and responsibility of curtailing exports before and during a load-shed event.
ERP 3	2	Policy	Develop a policy to ensure TOP emergency response and load-shed plans have been reviewed, updated and tested on an annual basis to verify their effectiveness, with attention to critical infrastructure.

OPERATOR TOOLS, COMMUNICATION AND PROCESS

Table 5: Summary of recommendations to the board related to operator tools, communications and processes

#	TIER	CATEGORY	RECOMMENDATION
OTCP 1	2	Action	Develop or enhance the tools, communications and processes identified by the ORWG and needed to improve SPP and stakeholder response to extreme conditions, such as: • Enhance real-time cascading analysis studies and post results. • Develop tool(s) to increase operator awareness of Out of Merit Energy (OOME) instructions. • Enhance and expand the use of R-Comm.[10] • Create a reliability dashboard to improve situational awareness for operators. • Utilize member-maintained distribution lists for communications purposes. • Develop a process to update operations management during extreme conditions.

[10] R-Comm is the Reliability Communications tool, the primary means of communication for responsible entities to receive, acknowledge and carry out load-shed instructions issued by the SPP Balancing Authority.

SEAMS AGREEMENTS

Table 6: Summary of recommendations to the board related to seams agreements

#	TIER	CATEGORY	RECOMMENDATION
SEAMS 1	2	Action	Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance and fairly compensate emergency energy.

MARKET DESIGN

Table 7: Summary of recommendations to the board related to market design

#	TIER	CATEGORY	RECOMMENDATION
MKT 1	2	Policy	Develop and improve policies to ensure price formation and incentives reflect system conditions.
MKT 2	2	Action	Develop and implement market design and market-related enhancements identified by the Market Working Group to improve operational effectiveness and ensure governing language provides needed flexibility and clarity, such as: • Improve the Dispatch Target Adjustment Process. • Enhance the Multiday Reliability Assessment Process.[11]
MKT 3	2	Policy	Develop policies to ensure financial outcomes during emergency conditions are commensurate with the benefits provided.

TRANSMISSION PLANNING

Table 8: Summary of recommendations to the board related to transmission planning

#	TIER	CATEGORY	RECOMMENDATION
TXP 1	2	Policy	Develop policies that facilitate transmission expansion needed to improve SPP's ability to more effectively utilize the transmission system during severe events.
TXP 2	3	Policy	Develop transmission planning policies that improve input data, assumptions or analysis techniques needed to better account for severe events.

[11] HITT recommendations R3 and R4 should be considered when addressing MKT 2.

CREDIT AND SETTLEMENTS

Table 9: Summary of recommendations to the board related to credit and settlements

#	TIER	CATEGORY	RECOMMENDATION
CR 1	2	Assessment	Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in the first quarter of 2022.
CR 2	3	Assessment	Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes.
CR 3	3	Action	Clarify tariff language related to SPP's settlements and credit-related authorities and responsibilities.

COMMUNICATIONS

Table 10: Summary of recommendations to the board related to communications

#	TIER	CATEGORY	RECOMMENDATION
COMM 1	2	Action	Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: • Processes that ensure stakeholders have a dependable way to receive timely, accurate and relevant information regarding emergencies. • Plans to drill emergency communications procedures with all relevant stakeholders. • Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers, and government entities and stay up-to-date.
COMM 2	2	Assessment	Evaluate and propose needed enhancements to communications tools and channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc.
COMM 3	3	Action	Form a stakeholder group whose scope would include discussion of matters related to emergency communications.
COMM 4	3	Action	To increase public awareness of and satisfaction with SPP, develop materials intended to educate general audiences on foundational electric utility industry concepts and SPP's role in ensuring electric reliability.

COMPREHENSIVE REVIEW PROCESS

SPP's comprehensive review of the February 2021 winter weather event included input from SPP staff and representatives of stakeholder groups including members, market participants, SPP's independent market monitor, regulators, elected officials and members of the media, among others. A steering committee was formed to ensure coordination and communication among parallel efforts conducted by the five teams identified below. Members of the steering committee were:

Lanny Nickell, Chair (SPP chief operating officer)

Larry Altenbaumer (Chair of the SPP Board of Directors)

Barbara Sugg (SPP president and chief executive officer)

Betsy Beck: Finance review co-lead (Members Committee representative, Enel Green Power North America director, organized markets)

Denise Buffington: Operations review lead (Evergy director of regulatory affairs)

Keith Collins: Market monitoring review lead (Executive director of SPP Market Monitoring Unit)

Tom Dunn: Finance review lead (SPP chief financial officer)

Kristie Fiegen: Regional State Committee review lead (South Dakota Public Utilities commissioner)

Joe Lang: Operations review co-lead (Members Committee representative, OPPD director of energy regulatory affairs)

Mike Ross: Communications review lead (SPP senior vice president of government affairs and public relations)

Reporting to the steering committee were five teams tasked with performing their own evaluations of various aspects of the February winter weather event's impacts. Each team's roster and scope are identified below along with notes regarding their evaluation process and/or outcomes.

OPERATIONS REVIEW

Four of SPP's working groups reviewed the event to develop recommendations: the Market Working Group (MWG), Operating Reliability Working Group (ORWG), Supply Adequacy Working Group (SAWG) and Transmission Working Group (TWG).

Operations Review Leads

Denise Buffington, chair
Evergy, SPP MOPC chair

Joe Lang
Omaha Public Power District

Market Working Group

Richard Ross, MWG chair
American Electric Power-Southwestern Electric Power

Jim Flucke, MWG vice chair
Evergy Companies

Erin Cathey, MWG staff secretary
SPP

Aaron Rome
Midwest Energy

Betsy Beck
Enel Green Power North America

Carrie Dixon
Xcel Energy

Chandler Brown
Sunflower Electric Power Corporation

Eric Alexander
Grand River Dam Authority

Jack Clark
NextEra Energy Resources

Jack Madden
East Texas Electric Cooperatives

John Varnell
Tenaska Power Services

Lee Anderson
Lincoln Electric System

Michael Massery
Arkansas Electric Cooperative Corporation

Neal Daney
Kansas Municipal Energy Agency

Rick Yanovich
Omaha Public Power District

Shawn Geil
Kansas Electric Power Cooperative

Shawn McBroom
Oklahoma Gas and Electric

Valerie Weigel
Basin Electric Power Cooperative

Yohan Sutjandra
City Utilities of Springfield

Operating Reliability Working Group

Allen Klassen, ORWG chair
Evergy Companies

Ron Gunderson, ORWG vice chair
Nebraska Public Power District

Zachary Sharp, ORWG staff secretary
SPP

Abubaker Elteriefi
ITC

Allan George
Sunflower Electric Power

Bryn Wilson
Oklahoma Gas & Electric

Chance Myers
Western Farmers Electric Cooperative

Chris Shaffer
American Electric Power

David Pham
The Empire District

Doug Peterchuck
Omaha Public Power District

Gary Plummer
Independence Power & Light

Jeff Wells
Grand River Dam Authority

Jim Useldinger
GridLiance High Plains

John Roemen
Western Area Power Administration

Keith Carman
Tri-State Generation and Transmission Association

Kyle McMenamin
Southwestern Public Service Company /Xcel Energy

Laurie Gregg
Lincoln Electric System

Mark Eastwood
City Utilities of Springfield

Matt Pawlowski
NextEra Energy Resources

Supply Adequacy Working Group

Natasha Henderson, SAWG chair
Golden Spread Electric Cooperative

Tom Hestermann, SAWG vice chair
Sunflower Electric Power Corporation

Chris Haley, SAWG staff secretary
SPP

Aaron Castleberry
Oklahoma Gas & Electric

Aaron Ramsdell
Basin Electric Power Cooperative

Adam Graff
Heartland Consumers Power District

Amy Newton
City Utilities of Springfield

Bennie Weeks
Xcel Energy Services

Brian Berkstresser
Liberty Utilities

Colton Kennedy
Omaha Public Power District

David Sonntag
Western Farmers Electric Cooperative

Eric Alexander
Grand River Dam Authority

Ernesto Perez
East Texas Electric Cooperative & Northeast Texas Electric Cooperative

Jeffrey Plew
NextEra Energy Resources

Jim Jacoby
American Electric Power-Public Service Co of OK

Jodi Knutson
WAPA

John Varnell
Tenaska Power Services

Robert Janssen
Dogwood Energy

Thomas Saitta
Kansas Municipal Energy Agency

Timothy Cerveny
Nebraska Municipal Power Pool

Traci Bender
Nebraska Public Power District

Walt Cecil, CAWG liaison
Missouri Public Service Commission

Transmission Working Group

Nathan McNeil, TWG chair
Midwest Energy

Derek Brown, TWG vice chair
Evergy Companies

Adam Bell, TWG staff secretary
Southwest Power Pool

Andrew Berg
Missouri River Energy Services

Arash Ghodsian
EDF Renewables Development

Chris Pink
Tri-State Generation and Transmission Association, Inc.

Clifford Franklin
Sunflower Energy

Gayle Nansel
Western Area Power Administration

James Ging
Kansas Power Pool

Jarred Cooley
Xcel Energy

Jason Shook
East Texas Electric Cooperative

Jim McAvoy
Oklahoma Municipal Power Authority

Joe Fultz
Grand River Dam Authority

John Boshears
City Utilities of Springfield, Missouri

John Knofczynski
East River Electric Power Cooperative

Joshua Verzal
Omaha Public Power District

Kalun Kelley
Western Farmers Electric Cooperative

Matthew McGee
American Electric Power

Michael Mueller
Arkansas Electric Cooperative Corporation

Michael Wegner
ITC Holdings

Nate Morris
Liberty Utilities

Noman Williams
GridLiance High Plains

Phil Westby
Basin Electric Power Cooperative

Randy Lindstrom
Nebraska Public Power District

Scott Benson
Lincoln Electric System

Shane McMinn
Golden Spread Electric Cooperative

Steve Hardebeck
Oklahoma Gas & Electric

SCOPE OF WORK

Immediately after the winter storm, SPP staff began analyzing the event. Staff prepared a draft report and shared it with members of the MWG, ORWG, SAWG and TWG. The report included information pertaining to operational activities and observations before and during the events.

The working groups met multiple times to review the draft event report and develop recommendations. The SAWG held six executive sessions to discuss the event and reviewed the recommendations at three regular meetings. The ORWG held 13 executive sessions dedicated to the event and discussed it at one regular meeting. The TWG held four executive sessions to discuss the event and reviewed recommendations at two regular meetings. The MWG held seven executive sessions dedicated to the event and discussed it at three regular meetings. The four groups held a joint executive session where all members could come together to collaborate.

FINANCIAL REVIEW

Staff from SPP's accounting, settlements and credit departments conducted SPP's financial analysis of the February 2021 winter weather event and validated their observations with the Finance Committee and Credit Practices Working Group.

Financial Review Leads

Tom Dunn, chair
SPP chief financial officer

Betsy Beck
Enel Green Power North America

SPP Staff

Brent Wilcox
SPP settlements

Dana Boyer
SPP settlements

Dianne Branch
SPP accounting

Don Shipley
SPP settlements

Jared Barker
SPP credit

Scott Smith
SPP credit

Steve White
SPP settlements

Tony Alexander
SPP settlements

Zeynep Vural
SPP accounting

Finance Committee

Susan Certoma, Chair
SPP Board of Directors

Sandra Bennett
American Electric Power

Julian Brix
SPP Board of Directors

Darcy Ortiz
SPP Board of Directors

Matt Pawlowski
NextEra Energy Resources

Sarah Stafford
OGE Energy

Al Tamimi
Sunflower Electric Power

Mike Wise
Gold Spread Electric Cooperative

Credit Practices Working Group

Caleb Head, CPWG chair
Northeast Texas Electric Cooperative

Mark Breese, CPWG vice chair
Xcel Energy

Seth Cochran
DC Energy

Tom Hestermann
Sunflower Electric Power Corporation

Mark Holler
Tenaska Power Services

LaGena O'Neal
Oklahoma Municipal Power Authority

Jason Regehr
City Utilities of Springfield, MO

Justin Riddell
The Energy Authority

Matthew Simon
Basin Electric Power Cooperative

Zachary Wegner
Omaha Public Power District

Terri Wendlandt
Evergy

SCOPE OF WORK

SPP's financial review focused on credit implications, settlement impacts and communication of financial matters as related to the February 2021 winter weather event. The observations and analysis detailed in the Analysis of Finance, Settlements and Credit section of this report are based on survey data, analysis of settlement disputes, the content of Request Management System tickets and settlement runs conducted by staff.

COMMUNICATIONS REVIEW

The Communications Comprehensive Review Team (CCR) comprised the following representatives of SPP and its stakeholder organizations. Its roster was intended to include individuals with responsibilities related to corporate communications, public relations, regulatory and government affairs and related fields, and to represent all of SPP's geographic regions and types of members.

Mike Ross, chair
SPP

Carl Stelly
SPP

CJ Brown
SPP

David Kimmel
OGE Energy

David Mindham
EDP Renewables

Derek Wingfield
SPP

Don Martin
SPP

Dustin Smith
SPP

Gina Penzig
Evergy

Jean Schafer
Basin Electric Power Cooperative

Jillian Janik
SPP

John McClure
Nebraska Public Power District

Kara Fornstrom
SPP

Kirkley Thomas
Arkansas Electric Cooperatives

Laura Lutz
Evergy

Lee Elliott
SPP

Leslie Sink
SPP

Lisa Meiman
Western Area Power Administration

Mark Becker
Nebraska Public Power District

Meghan Sever
SPP

Peter Main
American Electric Power/Southwestern Electric Power Company

Rae Rice
OGE Energy

Commissioner Randy Christmann
North Dakota Public Service Commission

Rob Roedel
Arkansas Electric Cooperatives

Russell Carey
SPP

Steve Gaw
Advanced Power Alliance

Tessie Kentner
SPP

Usha Turner
OGE Energy

Victor Schock
North Dakota Public Service Commission

SCOPE OF WORK

The CCR gathered documentation and data of relevant SPP communication from Feb. 4 through Feb. 20, and conducted an analysis of the processes, policies, staffing and resources used to conduct them. Analysis and recommendations covered four categories of communications:

- Operational communications.
- Stakeholder communications.
- Governmental and regulatory communications.
- Public communications (press, end-users and general public).

For each category, the CCR analyzed:

- What legal or standard requirements exist for SPP communication.
- How SPP's communication during the event met requirements.
- What procedures exist for additional communication.
- SPP's performance of internal procedures and processes.
- Communication performed by peers during the event.
- Other communication needs (perceived ⁄ expressed ⁄ relative) of operators, stakeholders, government and the public related to the event.

For each category, the CCR made recommendations to improve:

- *Internal* communication processes:
    - Interdepartmental communication.
    - Flow and responsibility of communication.
    - Resources provided for communication.
- *External* communication processes:
    - Effectiveness and timeliness of external communication.
    - Inclusion in each type of communication.
    - Stakeholder-driven communication process improvement.
    - Education about RTO emergency procedures and processes.
- *Member-conducted* communication processes:
    - Resources provided to SPP members to aid in communication.
    - Recommendations for standardizing public appeals and other processes.

For topics beyond the timeline and scope of the comprehensive review process, the CCR made some recommendations for additional analysis and recommendations, including topics for organizational groups or task forces to address in the future.

REGIONAL STATE COMMITTEE REVIEW

The Regional State Committee (RSC) of state utility commissioners, along with its Cost Allocation Working Group (CAWG), reviewed the winter event.

Regional State Committee

Kristie Fiegen, RSC chair
South Dakota Public Utilities Commission

Randel Christmann, RSC vice chair
North Dakota Public Service Commission

Paul Suskie, RSC staff secretary
SPP

Andrew French
Kansas Corporation Commission

Dana Murphy
Oklahoma Corporation Commission

Dennis Grennan
Nebraska Power Review Board

Geri Huser
Iowa Utilities Board

Jefferson Byrd
New Mexico Public Regulation Commission

Mike Francis
Louisiana Public Service Commission

Scott Rupp
Missouri Public Service Commission

Ted Thomas
Arkansas Public Service Commission

Will McAdams
Public Utility Commission of Texas

Cost Allocation Working Group

Greg Rislov, CAWG chair
South Dakota Public Utility Commission

Victor Schock, CAWG vice chair
North Dakota Public Service Commission

Lee Elliott, CAWG staff secretary
SPP

Adam McKinnie
Missouri Public Service Commission

Anna Hyatt
Iowa Utilities Board

Cindy Ireland
Arkansas Public Service Commission

Harika Basaran
Public Utility Commission of Texas

Jason Chaplin
Oklahoma Corporation Commission

John Krajewski
Nebraska Power Review Board

John Reynolds
New Mexico Public Regulation Commission

Lane Sisung
Louisiana Public Service Commission

Shari Albrecht
Kansas Corporation Commission

SCOPE OF WORK

RSC President Kristie Fiegen created the Cost Allocation Working Group Ad Hoc Task Force in response to the extreme weather event. The task force members were John Krajewski, John Reynolds and Shari Albrecht. The task force was charged with gaining a broad understanding of the factors that resulted in the emergency and developing recommendations related to the RSC's authority: cost allocation, financial transmission rights, resource adequacy and transmission planning for remote resources.

The task force interfaced with SPP staff, the MMU, the SAWG and the RSC in developing their recommendations. In total, the RSC review team held 32 meetings to discuss the event and develop recommendations.

The task force's report is posted on the SPP.org RSC page.

MARKET MONITORING UNIT REVIEW

Keith Collins, executive director of SPP's independent Market Monitoring Unit (MMU), led the MMU's review of the winter event. MMU staff invested a significant amount of effort into researching and analyzing what happened during the storm, including issues related to FERC Order No. 831, price formation, generation outages, scheduling and dispatch, and gas-electric coordination.

They engaged with the MWG, SAWG, ORWG, CPWG, CAWG, and communications review team to hear stakeholder concerns and discuss issues. The MMU held discussions with the Federal Energy Regulatory Commission and other independent system operators/regional transmission organizations regarding the event and related best practices.

The MMU's report and recommendations are posted to the MMU's page on SPP.org.

EVENTS OF FEB. 4-20

The winter weather event of February 2021 was historic in nature, requiring SPP to take steps to preserve the reliability of the regional power grid that it has not previously taken in its 80-year history. The entire SPP balancing authority (BA) region, stretching from the Canadian border in the north to the Texas panhandle in the south, was impacted by extreme cold temperatures that lasted days. This led to increased electricity use at the same time a number of factors limited generators' ability to produce power. Still, over the course of the week, SPP limited service interruptions to a total of just more than four hours spread over two days.

On the following pages are a timeline and review of the events leading up to, during and immediately following the winter storm. This report's appendices contain additional background information on subjects pertaining to SPP's role in managing regional reliability and preparing for winter-weather events like this one. See the appendices for information on these and other background topics:

- SPP's and its members' roles in assuring electric reliability
- Winter-weather preparation and training taken by SPP and stakeholder operations staff
- Industry standards related to SPP's and its members obligations during the winter weather event
- Findings and SPP's response to prior winter-weather reliability events in 2011 and 2018

The section titled Analysis of Operational and Market Performance presents a detailed evaluation and observations regarding the events described above.

Figure 1 is an illustrated timeline of SPP Balancing Authority operations from Feb. 4-20, 2021, followed by a high-level overview of five phases of the event: early forecasts, conservative operations, the declaration of a series of energy emergency alerts, controlled interruptions of service, and a period of lessening severity concluding with a return to normal operations. Note that time blocks in the following illustration are not to scale.

Thurs. 2/4 to Mon. 2/8	Tues 2/9 to Sat. 2/13	Sun. 2/14	Mon. 2/15	Tues. 2/16	Wed. 2/17	Thurs. 2/18	Fri. 2/19	Sat. 2/20
Normal operations in effect	**Tues. 2/9:** Declared conservative operations until further notice **Thurs. 2/11:** Began to commit generating resources multiple days in advance for Sat. 2/13 to Tues. 2/16 **Sat. 2/13:** Reminded market participants of emergency cap & offer processes	Requested member companies issue public appeals for conservation Declared EEA1 to be effective 2/15 at 05:00	Conservative operations in effect	EEA2 in effect	EEA 2 in effect	EEA1 in effect	EEA1 in effect	Conservative operations in effect
Thurs. 2/4: Issued cold weather alert to grid operators			05:00 Declared EEA1	06:15 Declared EEA3	13:15 Declared EEA1	09:30 Ended EEA and remained in conservative operations through 22:00 Sat. 2/20, with appeal for public conservation	09:20 Ended EEA and remained in conservative operations through 22:00 Sat. 2/20, with appeal for public conservation	22:00 Declared normal operations
Mon. 2/8: Issued resource alert to grid operators: "Implement resource preparations...ensure resource commitment start-up and run times ...report fuel shortages & transmission outages..."			07:22 Declared EEA2	06:44 Demand interruption	18:20 Declared EEA2	18:25 – Declared EEA1		
			10:08 Declared EEA3 New record peak	10:07- Load restored, still EEA3	22:59 Declared EEA1			
			12:04 - Demand interruption	11:30 Declared EEA2				
			13:01 - Load restored, still EEA3	12:31 Declared EEA1				
			14:00 Declared EEA2	18:28 Declared EEA2				

Figure 1: Timeline of BA Operations (Feb. 4-20, 2021)

REVIEW OF FEB. 4-20 ACTIVITIES

WEATHER

In February 2021, a major winter storm impacted the SPP region and much of the continental United States. On Feb. 14, the National Weather Service Prediction Center tweeted, "This cold snap is forecast to result in record low temperatures that are comparable to the historical cold snaps of Feb 1899 & 1905."[12] According to the National Operating Hydrologic Remote Sensing Center, on Feb. 16, about 73% of the mainland U.S. was covered in snow.[13] On Feb. 19, the National Weather Service tweeted that over 3,000 daily record cold temperatures had been reported, and within that dataset were 79 all-time cold records.[14]

The SPP region was inside the coldest portion of the continental U.S., as depicted in the following map.

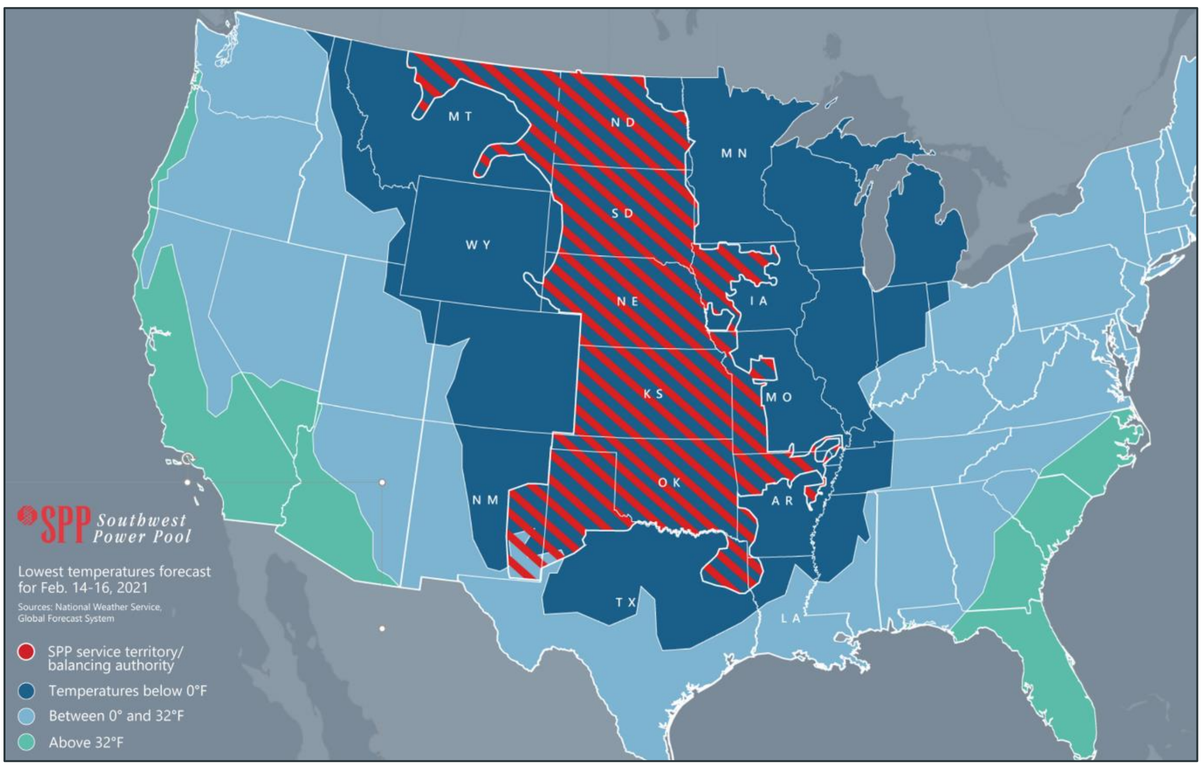

Figure 2: Low-Temperature Map

[12] https://twitter.com/NWSWPC/status/1361000008519086085
[13] https://www.nohrsc.noaa.gov/nsa/index.html?region=National&year=2021&month=2&day=16&units=e
[14] https://twitter.com/NWSWPC/status/1362953109681672199

EARLY FORECASTS

First communication to member utilities about possible impacts of the winter storm occurred Feb. 4, 10 days before the storm hit.

1. **Feb. 4:** SPP issued a Cold Weather Alert effective Feb. 6. A Cold Weather Alert signals that forecasts anticipate extreme weather that could impact grid reliability.

2. **Monday, Feb. 8 at 10 a.m.**: SPP escalated status to Resource Alert. A Resource Alert signals that member utilities should implement resource preparations, ensure resource commitment startup and run times, and report fuel shortages and transmission outages that might impact normal operations.

CONSERVATIVE OPERATIONS AND OTHER PREPARATORY ACTIVITIES

3. **Tuesday, Feb. 9 at 12 a.m.**: SPP declared a period of Conservative Operations until further notice. SPP does this periodically when weather, environmental, operational or other events prompt us to operate the system conservatively to avoid an emergency.

4. **Thursday, Feb. 11**: SPP began committing generating resources using its multiday reliability assessment process. Instead of committing generation a day ahead, as is standard practice, SPP began sending instructions to generators several days in advance that they would be responsible for serving load for the period Saturday, Feb. 13 through Tuesday, Feb. 16.

ENERGY EMERGENCY ALERTS AND PUBLIC APPEALS

5. **Sunday, Feb. 14**

    a. **9:27 a.m.**: SPP emailed a declaration of an Energy Emergency Alert (EEA) Level 1 beginning Feb. 15, 2021, at 5 a.m. due to concerns regarding expected weather and fuel-supply issues.

    b. **1:57 p.m.**: SPP requested member utilities make public appeals for energy conservation effective beginning on Feb. 15.

    This marks the first time in SPP's history it has taken this step. A public appeal is a tool SPP has available to lessen electricity use when it forecasts that its generating capacity and reserves are at risk. A public appeal for conservation precedes service interruptions by calling for voluntary reductions, in hopes it will prevent the need for mandatory curtailments.

6. **Monday, Feb. 15 at 5 a.m.:** The SPP BA entered EEA Level 1 for its entire region. EEA Level 1 signals that all available generation is in use.

   Due to the expected severity of this winter storm's impacts, SPP had already issued a public appeal for conservation by this time. Public appeals typically follow an EEA Level 1, but SPP determined if public conservation were to have the desired effect, it would have to be done quickly. The decision proved beneficial: Actual load came in under forecast, at least partly because people responded and used less electricity than predicted.

7. **Monday, Feb. 15 at 7:22 a.m.:** SPP escalated to EEA Level 2. This marks the first time it had ever done so for its entire region.

   EEA Level 2 indicates that in addition to using all available generation, operating reserves are at risk of dropping below minimum requirements. It is at this point SPP typically would direct public appeal for conservation, but it had already done so given the extreme conditions the SPP BA region faced.

8. **Monday, Feb. 15 at 8:58 a.m.:** Even as load came in under forecast, SPP set an all-time peak of 43,661 megawatts (MW) for systemwide electricity use in winter across its region. This underscores the historic nature of this event: Even while using tools like voluntary conservation appeals, SPP still set a new winter peak.

9. **Monday, Feb. 15 at 10:08 a.m.:** SPP declared its first-ever regionwide EEA Level 3, the most severe of three EEA levels.

   EEA Level 3 indicates energy reserves have dropped below minimum requirements, meaning SPP has to find additional generation — by importing it or bringing another plant online — or lessen regionwide electricity use to keep the system in balance.

CONTROLLED INTERRUPTIONS OF SERVICE

10. **Monday, Feb. 15 at 12:04 p.m.:** Two hours after declaring an EEA Level 3, and having exhausted all other options, SPP directed member utilities to deliberately curtail region's energy use by 1.5%. This controlled interruption of service (also called a "load-shed event" lasted 57 minutes.

    When SPP directs controlled interruptions, it spreads their impacts across the whole region. For example, if demand exceeds supply by 100 MW, SPP asks each transmission operator (TOP) throughout the region to decrease electricity use by a proportional share to bring the whole system back into balance. The most load a single TOP was asked to shed during this interruption was 101 MW, or about 17% of the total by which we needed to lessen regional energy use at the time.

    It's up to each TOP to determine how to lessen its use, whether by curtailing residential, commercial or industrial load. SPP has no visibility into and has no authority to direct

how utilities lessen their load. In other words, there's no way for SPP to see or direct whether that reduction comes from particular homes, neighborhoods, farms, businesses, factories, etc. SPP simply monitors the aggregate impact of TOPs' actions to ensure the reliability of the regional grid.

11. **Monday, Feb. 15 at 1:01 p.m.**: SPP restored all load, bringing an end to the period of controlled interruptions of service that began at 12:04 p.m.

12. **Monday, Feb. 15 at 2 p.m.:** SPP declared an EEA Level 2, having restored minimum reserves, and remained in an EEA Level 2 for the duration of that day.

13. **Tuesday, Feb. 16**: The region's electricity use rose again during the typical morning peak — a natural occurrence as people woke up, raised their thermostats, began using appliances, went to work, etc.

14. **Feb. 16 at 6:15 a.m.:** SPP declared a second EEA Level 3.

15. **Feb. 16 at 6:44 a.m.:** SPP directed its member TOPs to implement controlled interruptions of service for a second time.

    The second interruption of service lasted three hours and 21 minutes and was required to lessen regional electricity use by 6.5%. As before, SPP spread the impact out across the region, asking TOPs to decrease their use by a proportional share of this total 6.5% reduction. The most a single entity had to shed in this event was about 227 MW, again about 17% of the total by which SPP needed to lessen total regional energy use.

16. **Feb. 16 at 10:07 a.m.:** SPP restored load, bringing an end to the second and final controlled interruption of service of the winter weather event.

RETURN TO NORMAL OPERATIONS

17. Throughout the remainder of the week, from **Tuesday, Feb. 16 at 11:30 a.m. until Friday, Feb. 19 at 9:20 a.m.**, SPP fluctuated between EEA Levels 1 and 2, de-escalating to Conservative Operations with no EEAs for several hours (9:30 a.m.-6:25 p.m.) on Thursday, Feb. 18.

18. **Saturday, Feb. 20 at 10 p.m.**: SPP declared an end to all applicable alerts and returned to normal operations.

EARLY GENERATION COMMITMENTS

Per the SPP BA Emergency Operating Plan, during a period of conservative operations, the SPP BA may take actions including the use of greater unit commitment notification timeframes, and making commitments prior to the day-ahead market (DAMKT) and/or committing resources in reliability status.

During the week of Feb. 7, SPP was notified of growing concerns about natural gas availability for the upcoming week. Staff worked to ensure all available resources were utilized.

SPP carried out several multiday Reliability Unit Commitment (RUC) studies, committing resources of various lead times well in advance of the DAMKT. These commitments were issued to give early notice that the resources would be needed in real time and that fuel should be procured accordingly. Figure 3 shows the amount of economic maximum capacity committed in each of the market's assessments, distinguished by case (i.e., the results of each assessment). The horizontal axis indicates the timeframe for which the commitments were made.

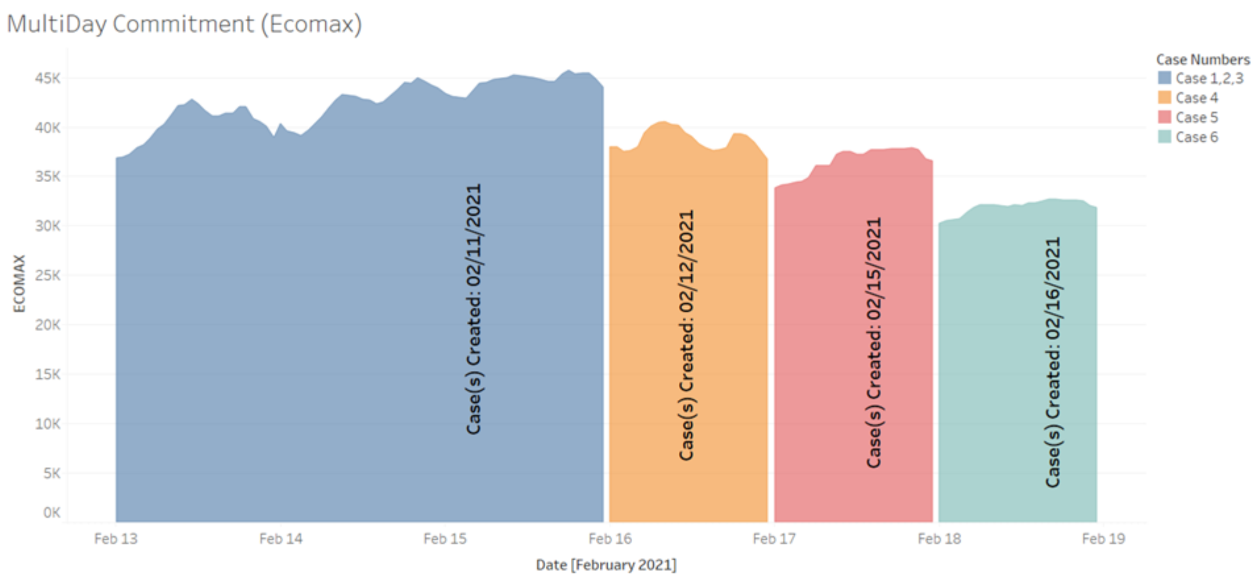

Figure 3: Multiday Commitment Cases

RESCHEDULED TRANSMISSION OUTAGES

Beginning Feb. 9, operations planning staff worked with TOPs to reschedule 134 transmission outages planned to take place Feb. 14-19. Figure 4 illustrates the number of outages rescheduled by kilovolt level. Outages that were previously implemented or were due to emergent work were not rescheduled. Approximately 130 transmission outages of various equipment types and voltage levels were ongoing throughout the event. Outages that were previously implemented or were due to emergent work were not rescheduled.

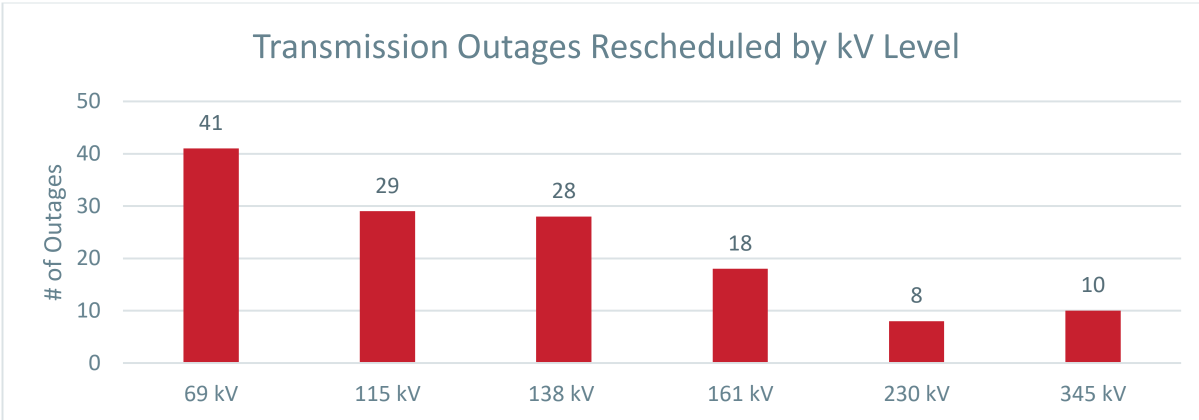

Figure 4: Rescheduled Transmission Outages (Feb. 14-19)

RESCHEDULED GENERATION OUTAGES

SPP allows a certain amount of planned generation outages on the system during the month of February. Over the last five years, planned generation outages during this time of year average around 6,000 MW. As shown in Figure 5, planned outages ran higher than normal during the early part of February but dipped below historical averages during the winter event.[15] This was primarily due to proactive efforts taken to reschedule planned maintenance.

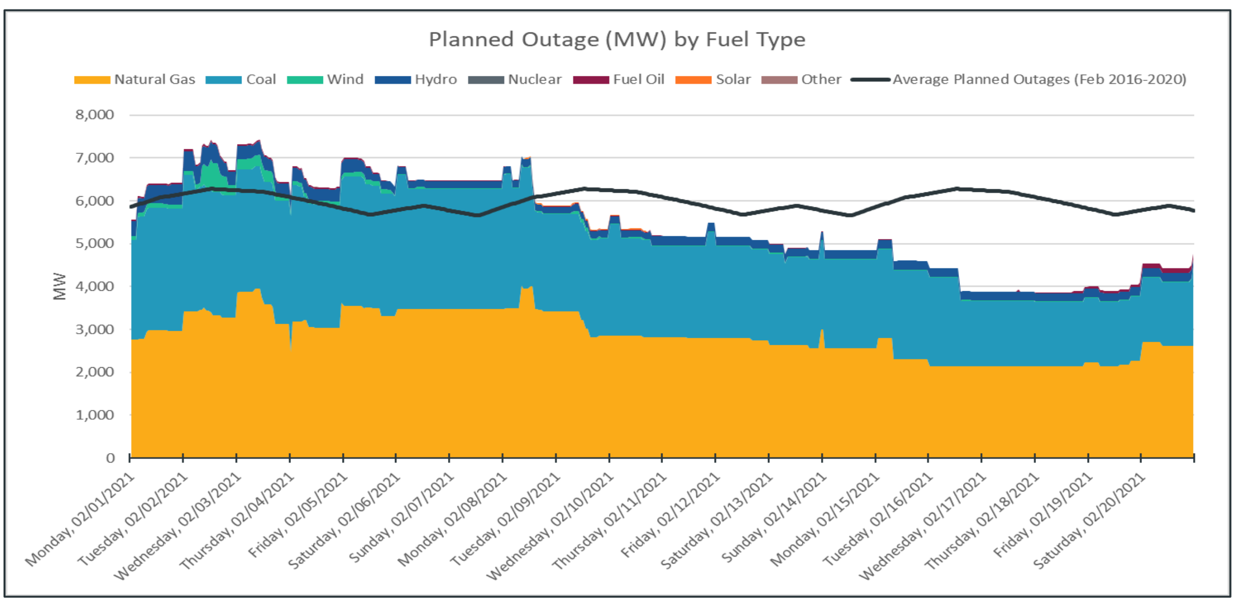

Figure 5: Planned Outages by Fuel Type (Feb. 1-20, 2021)

[15] Due to the nature of some planned outage maintenance, certain outages were not recallable during February 14-19.

Operations planning staff began working with GOPs on Feb. 9 to reschedule generation outages planned to take place Feb. 14-19. Outages that were previously implemented or were due to emergent work were not rescheduled. Resources in the midst of maintenance work may not have been recallable and maintained the original schedule.

Figure 6 illustrates the number of outages and associated capacity rescheduled by fuel type. The rescheduled outages account for roughly 4 gigawatts (GW) of generation capacity. The data includes outages that were canceled, moved or denied.

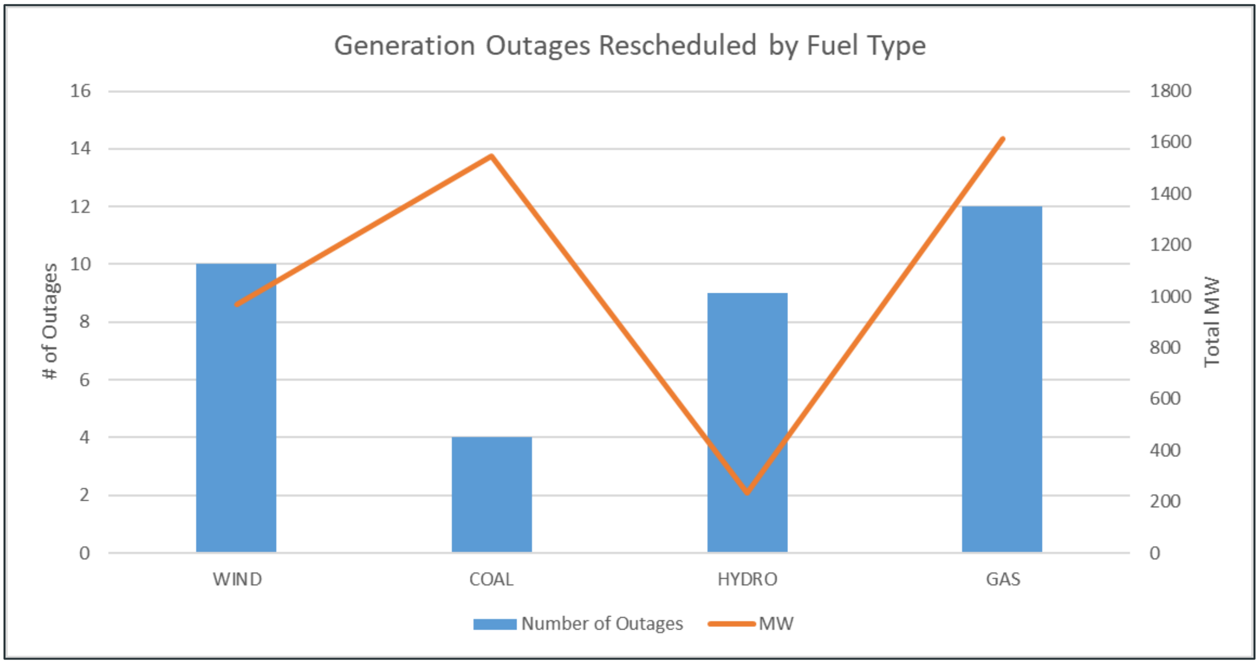

Figure 6: Rescheduled Generation Outages (Feb. 14-19)

LOAD

SPP experienced high winter load levels for multiple days leading up to Feb. 15. On the morning of Feb. 15, load reached 43,661 MW surpassing SPP's previous winter load peak of 43,584 MW set Jan. 17, 2018. It is noteworthy that this new winter load peak was reached Feb. 15 while SPP was taking actions, including issuing public requests for energy conservation, to reduce system load. SPP's midterm load forecasting applications projected load in excess of 44,000 MW for Feb. 15 and 47,000 MW for Feb. 16.

It is difficult to accurately determine how much higher SPP's system load may have been had load management procedures not been in effect during those times but it is likely SPP's previous winter load peak would have been surpassed by nearly 8% if sufficient generating resources had been available.

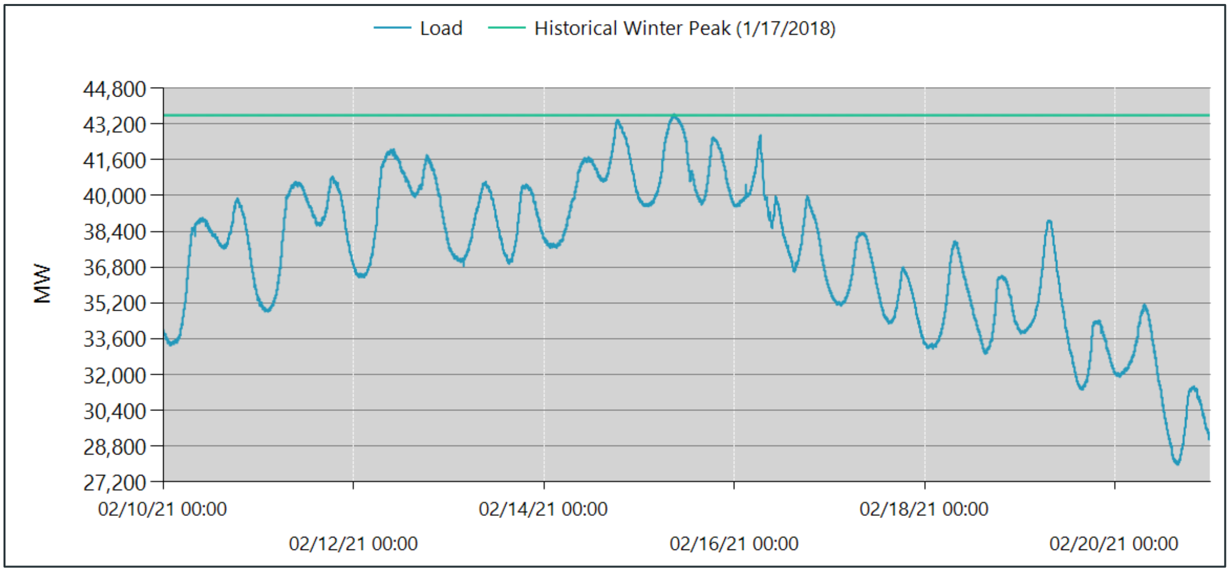

Figure 7: SPP BA load and historical winter peak

LOAD FORECASTING

The projected non-coincident peak load forecasted leading into the 2020-2021 winter season was approximately 43,700 MW. During the 2021 winter weather event, the SPP BA experienced a coincident peak demand of 43,661 MW. During this event, the highest forecasted day-ahead peak load was close to 46,000 MW while midterm forecasts indicated peak loads as high as 47,000 MW for Feb. 16.

SPP's day-ahead load forecasts projected higher load levels than were observed in real time for much of the week of Feb. 15. A few factors may have contributed to this over-forecasting of system load, including:

- President's Day holiday Monday, Feb. 15.
- Public appeals and load management.
- Commercial customer reductions following system load-shed events.
- Winter weather including snow and ice caused abnormal load behavior due to school and work closures.

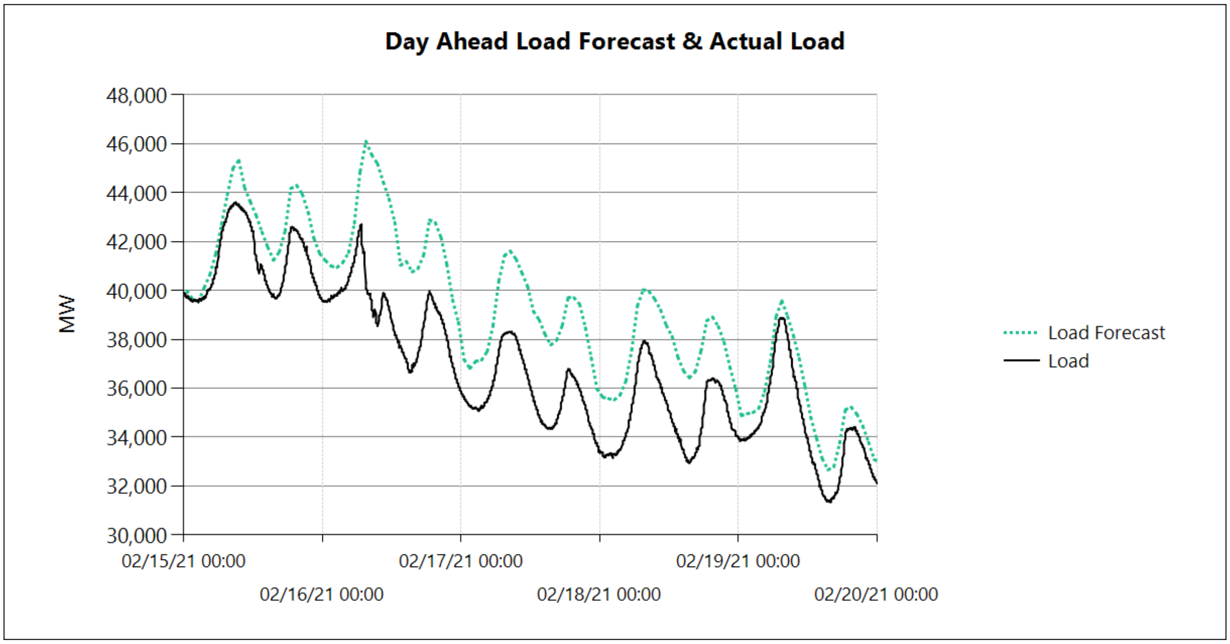

Figure 8: Day-ahead load forecast and actual load

WIND FORECASTING

Figure 9 shows the performance of the day-ahead wind forecast during the week of Feb. 15. The deviation observed late Feb. 15 through the morning of Feb. 17 was in part due to curtailments associated with system congestion.

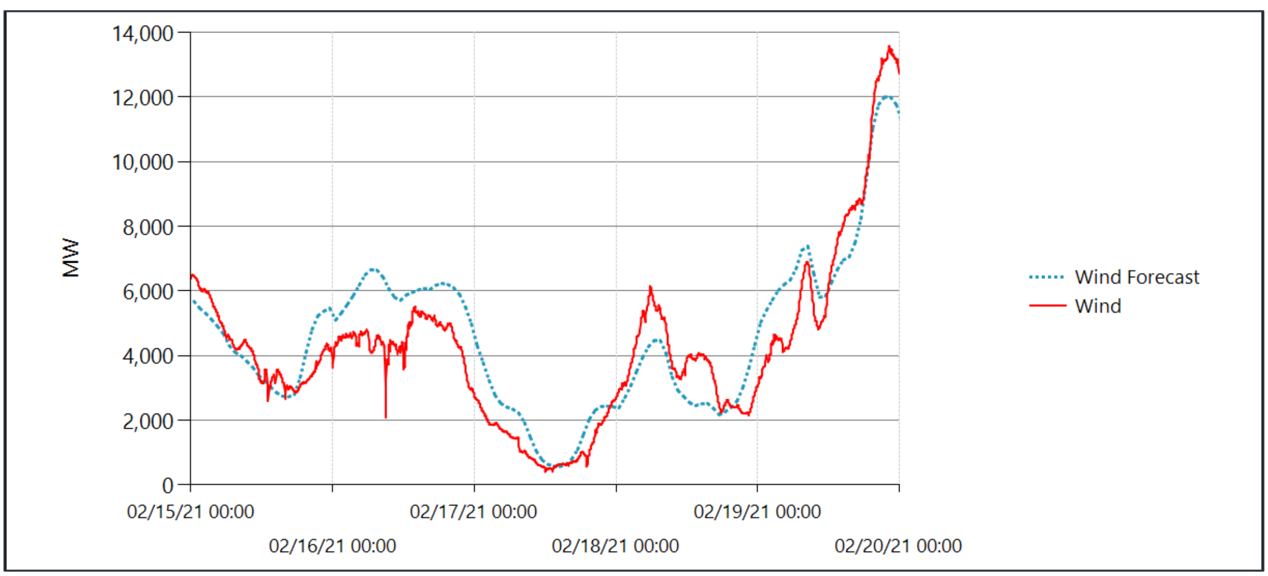

Figure 9: Day-ahead wind forecast and actual wind

MONDAY, FEB. 15: IN-DEPTH REVIEW

On Feb. 15, available capacity became insufficient to meet system demand. At 12:04 p.m., SPP directed 610 MW of load shed. Figure 10 shows online available generation combined with net scheduled interchange, load and Area Control Error (ACE). ACE is the instantaneous difference between a BA's scheduled and net actual interchange, taking into account the effects of frequency bias and correction for meter error. Near the time of load shed, when available generation fell below load, SPP experienced negative ACE indicating that the SPP BA was deficient and relying on unscheduled imports from the Eastern Interconnection to serve load. The morning outage and fail-to-start total of 3,790 MW at 10 a.m. represents capacity on resources that were in the current operating plan (COP) but failed to meet their commitment.

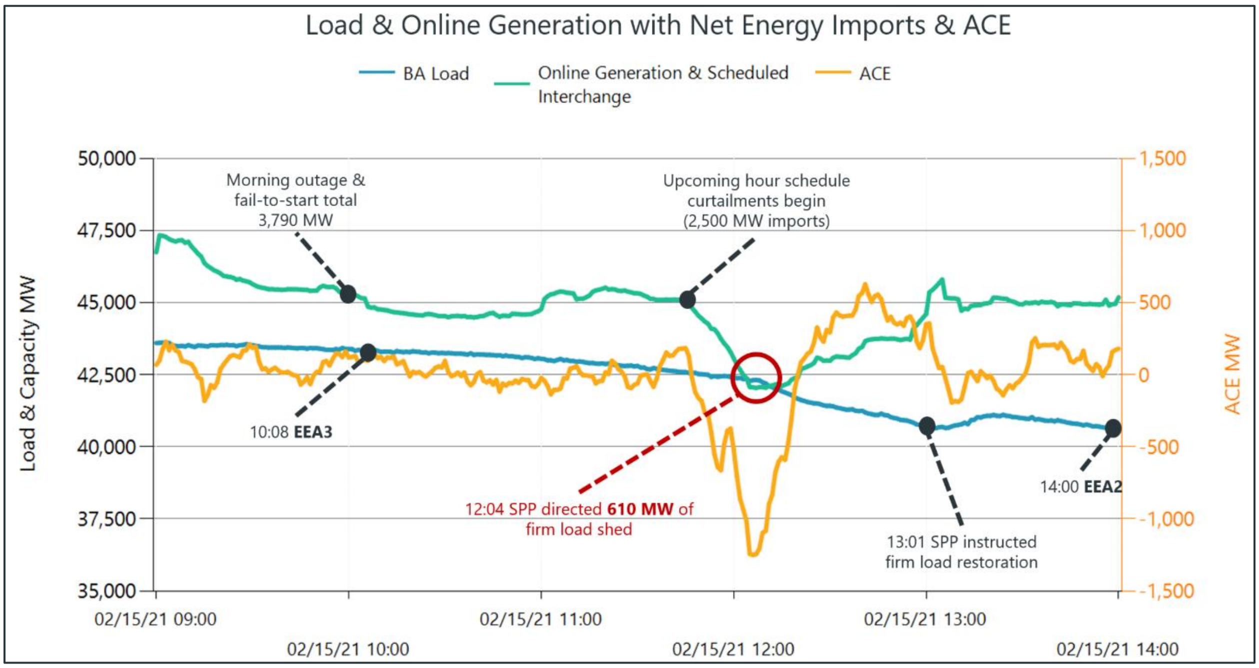

Figure 10: Load & Capacity with Area Control Error (ACE) (Feb. 15, 2021)

At the time of load shed, the real-time balancing market (RTBM) was completely deficient of reserves and dispatchable headroom. Capacity was present on resources that were manually reduced by out-of-merit-energy (OOME) instructions. This capacity was not deliverable due to transmission constraints and could not be utilized to serve load. Figure 11 shows the general areas of online capacity near the time of load shed Feb. 15. For this snapshot, a total of 648 MW of capacity was manually reduced. The red arrow indicates the region and direction of flow of the constraint that drove the manual reductions.

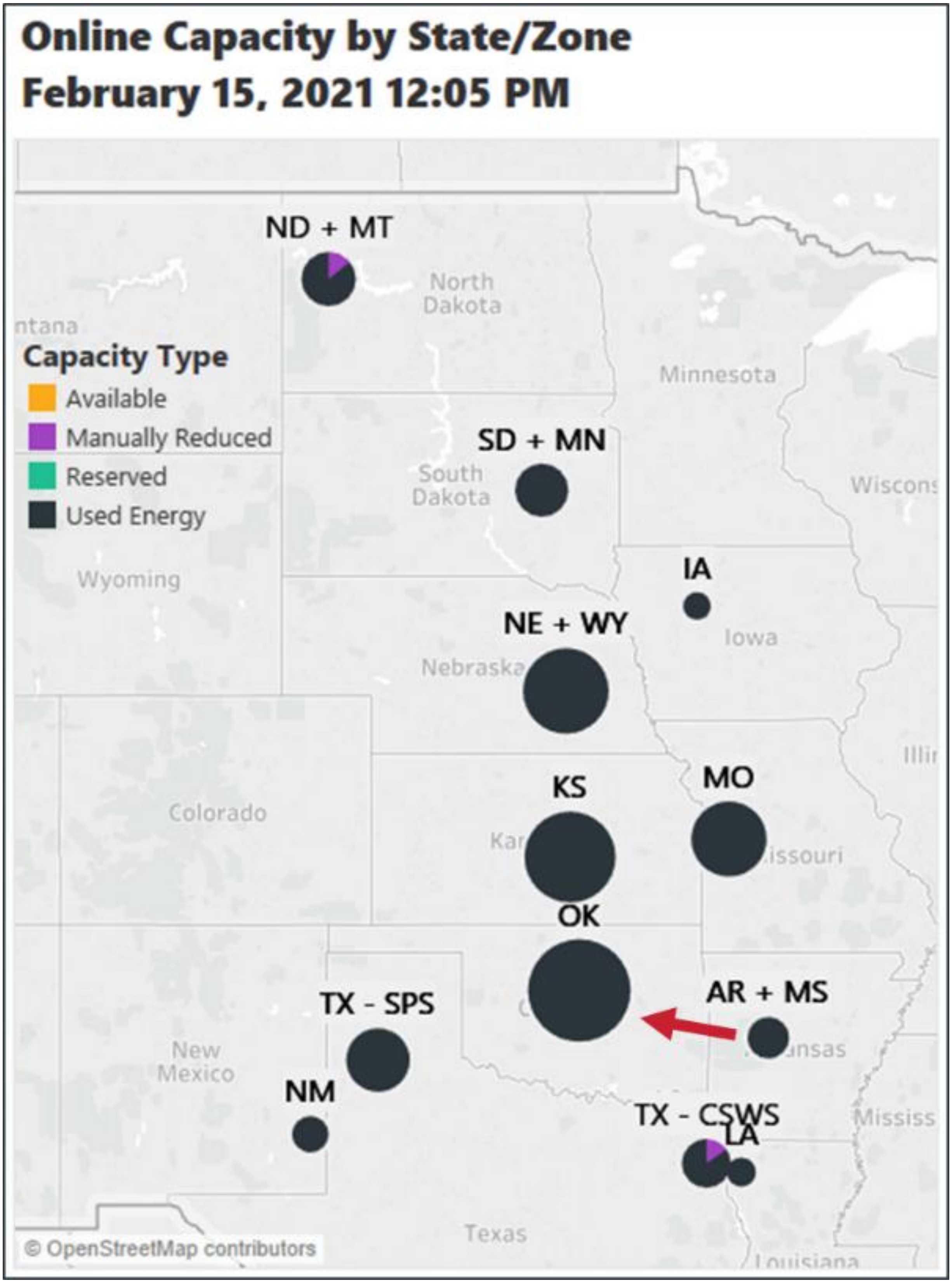

Figure 11: Map of online capacity (Feb. 15, 2021)

TUESDAY, FEB. 16: IN-DEPTH REVIEW

On Feb. 16, SPP directed a total of 2,718 MW of load shed: 1,359 MW at 6:44 a.m. and an additional 1,359 MW at 7:17 a.m. SPP also initiated the curtailment of up to 287 MW of firm exports as a share of SPP firm load obligation interruption. SPP sent its first instructions to partially restore load at 9:32 a.m., and sent subsequent instructions to restore the remainder of load at 10:07 a.m., effectively indicating that all load effected by the load-shed instructions could be returned to service. Figure 12 illustrates load and online generation with net energy imports and ACE during the morning of Feb. 16.

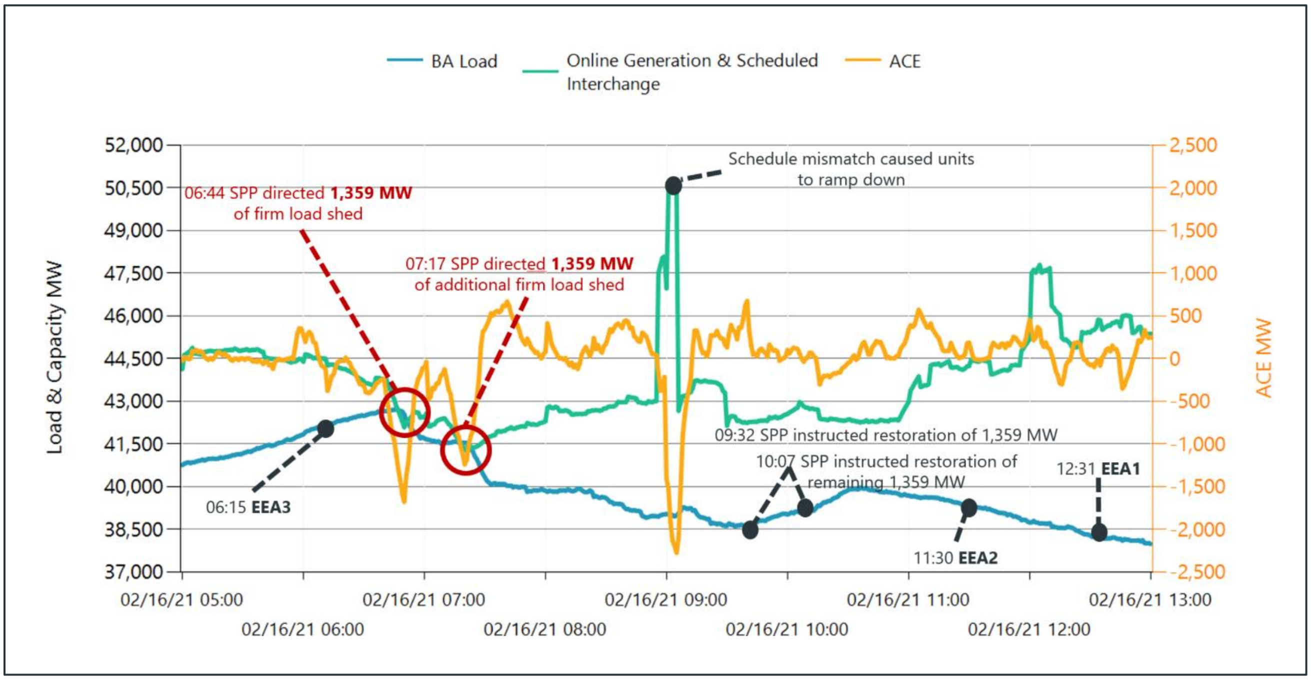

Figure 12: Load & Capacity with ACE (Feb. 16, 2021)

Near the time SPP issued load-shed instructions, the RTBM was unable to clear dispatchable headroom and was clearing only a small amount of reserves. As on Feb. 15, there was undeliverable capacity present on resources that were manually reduced. Figure 13 shows the general areas of online capacity near the time of load shed Feb. 16.

For this snapshot, a total of 1,862 MW was the manually reduced. Manual reductions were in place on several different resources to mitigate loading on various constraints across the SPP region. The red arrows indicate the locations and directions of flow for a few of the main constraints limiting generation.

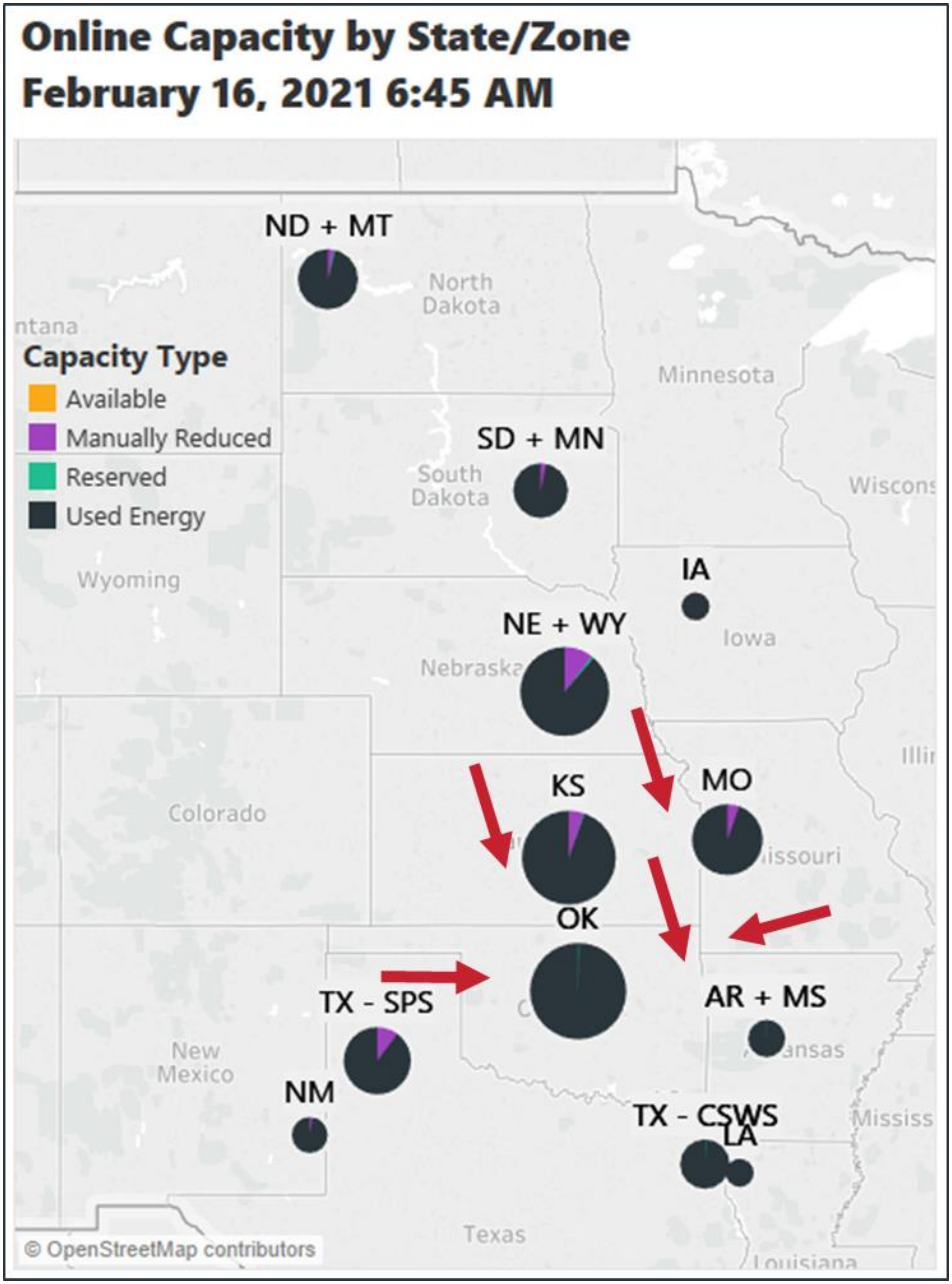

Figure 13: Online capacity map (Feb. 16, 2021)

WEDNESDAY, FEB. 17-FRIDAY, FEB. 19: OVERVIEW OF OPERATIONS

Although the worst of the event had passed, SPP continued to experience moments during Feb. 17-19 where its energy supply encroached on its ability to meet load and reserve requirements, requiring the declaration of heightened levels of Energy Emergency Alerts. Figure 14 shows generation with scheduled interchange and load, as well as load with contingency reserves.

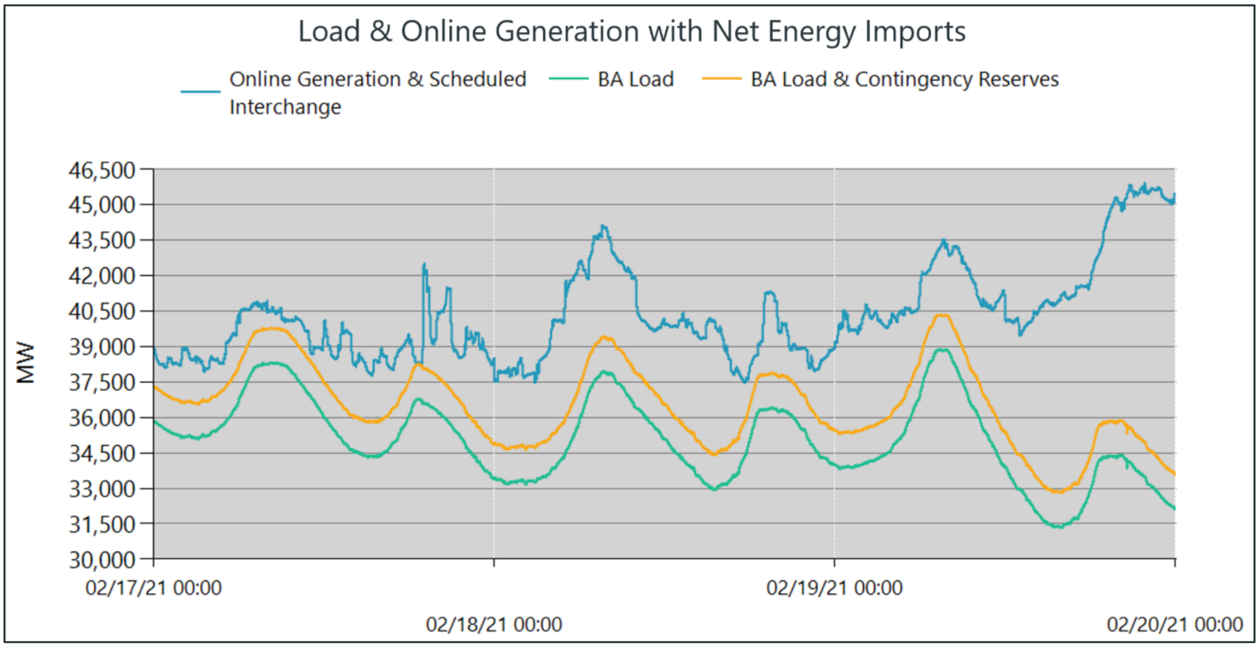

Figure 14: Load, Capacity and Load with Contingency Reserves (Feb. 17-19, 2021)

ANALYSIS OF OPERATIONAL AND MARKET PERFORMANCE

GENERATION AVAILABILITY AND FUEL ASSURANCE

During the 2021 winter weather event, all resource types experienced challenges ranging from operational reductions to total resource outages resultant from either frozen equipment or interrupted fuel supplies.

GENERATION ASSESSMENT PROCESS

SPP utilizes its Generation Assessment Process (GAP) to help ensure the SPP Balancing Authority's obligations can be met and to identify timeframes of allowable maintenance margin. The GAP methodology was reviewed and endorsed by the Operating Reliability Working Group. GAP is executed three times daily and results are posted publicly to ensure the most accurate information is available to generator owners/operators looking to schedule outages. SPP uses this information as part of its outage pre-approval process.

GAP creates a data set of actual historical values from the previous three years for all intervals plus and minus 15 days from the operating day. Maintenance margin calculation considerations include: total installed generation capacity (excluding variable energy resources), historical forced generation outages, current scheduled generation outages, historical wind performance, historical load and historical operating reserves.

CAPACITY AVAILABILITY

Based on historical averages over the past five years, SPP's market typically has about 55 gigawatts (GW) of available generation capacity[16] in February. As illustrated in Figure 15, that capacity dipped to roughly 35 GW during the week of Feb. 14, 2021. This 20 GW reduction from typical available capacity was primarily due to higher than usual fuel-supply deficiencies, wind-turbine freezing, and other challenges associated with operating equipment in extremely cold conditions such as frozen cooling towers, intakes, fuel lines, transmitters, etc. On Feb. 15 and 16, roughly 50% of forced generation outages cited fuel-supply issues as their cause.

[16] Includes reported available capacity of nonvariable resources and forecasted available energy from variable resources.

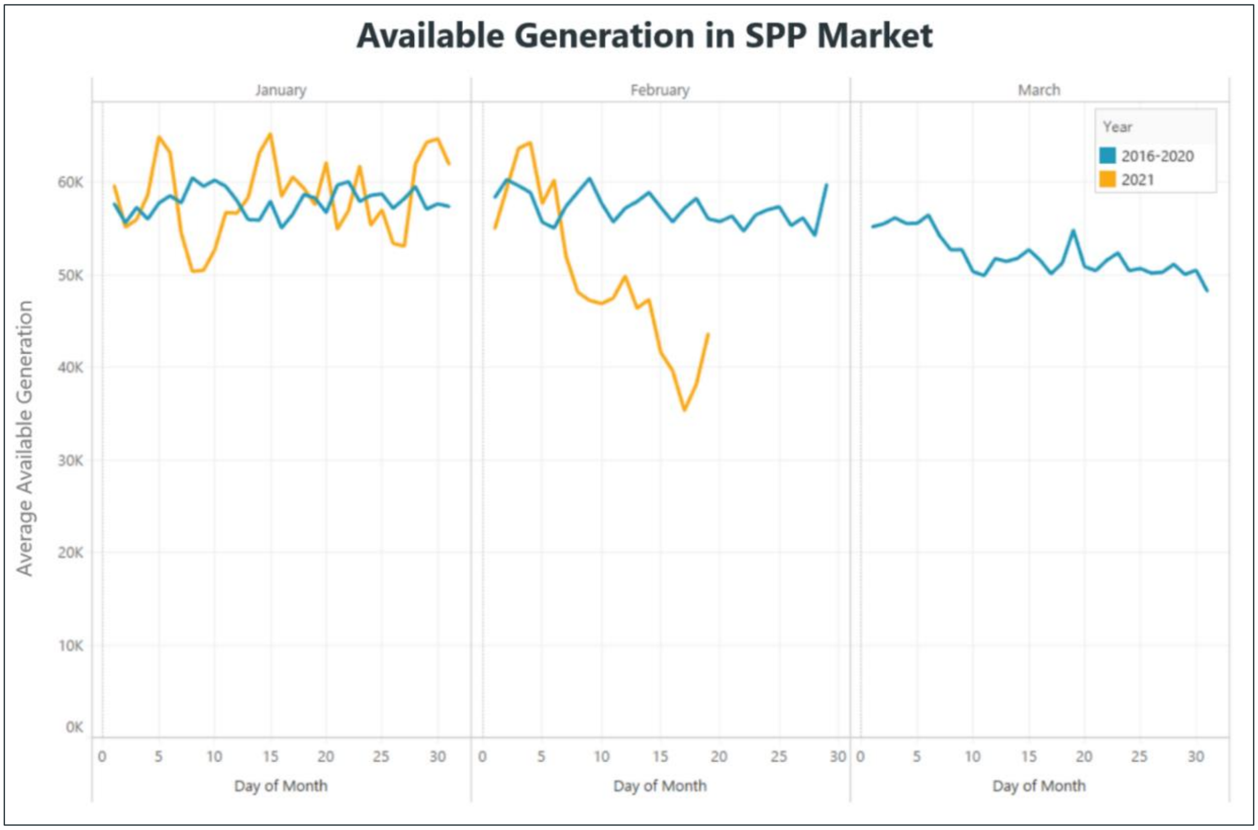

Figure 15: Available Generation in the SPP Market

FORCED OUTAGES

Figure 16 shows the forced generation outages in effect by fuel type during the two weeks preceding and the week of the event.

On Feb. 7, freezing rain and freezing fog moved into the central and southern regions of SPP (Kansas, Oklahoma and the Texas panhandle) and reduced available wind capacity due to ice buildup on turbine blades. Natural gas supply was limited due to extremely cold temperatures across the central U.S. [17]

SPP observed up to approximately 33 GW of forced outages during the week of the event, with an average of 30.5 GW of forced outages Feb. 16. Natural gas generation experienced an average of nearly 18 GW of forced outages during Feb. 16, and of those outages, nearly 75% cited lack of fuel supply as the cause.

[17] Members and market participants submitted CROW tickets indicating icing issues on wind resources and fuel supply concerns for natural gas generators.

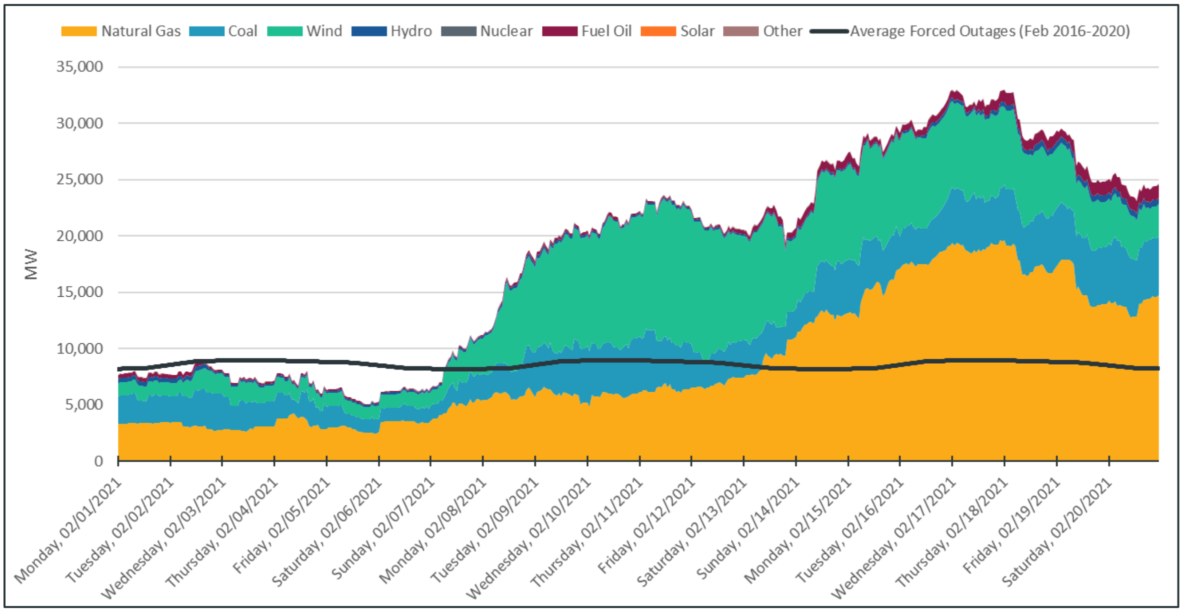

Figure 16: Forced generation outages as submitted in CROW by Fuel Type

Figure 17 shows the total generation unavailable due to forced outages, distinguished by the cause for the outage[18] as submitted into SPP's outage scheduling tool, Control Room Operations Window (CROW). On average, over 48% of all forced outages experienced during the week of the event were caused by fuel supply issues.

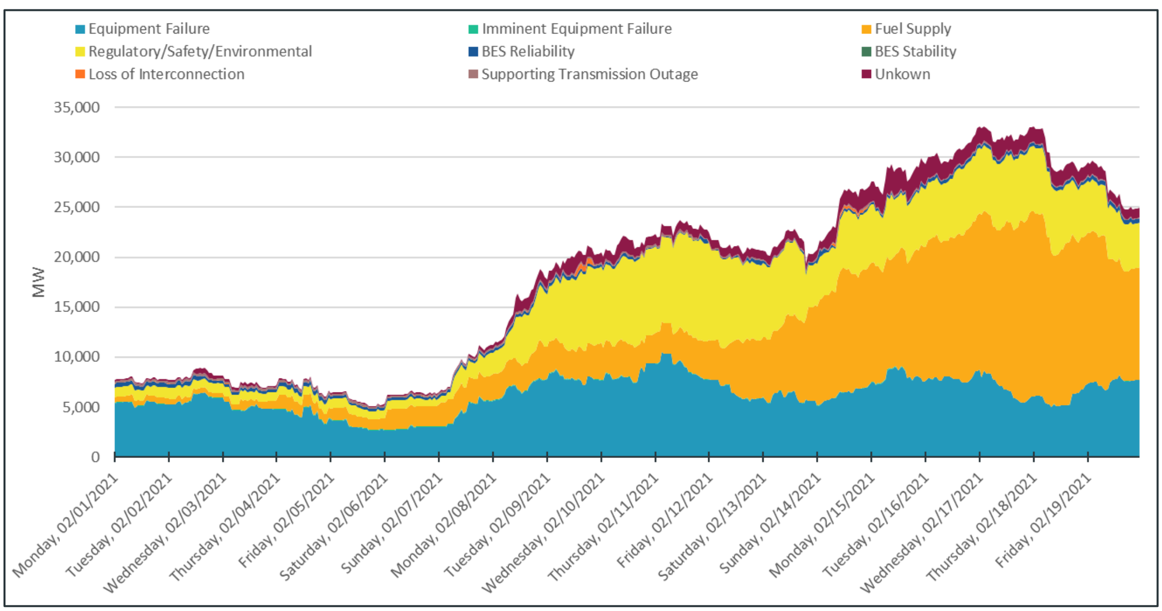

Figure 17: Forced generation outages as submitted in CROW by Cause Code

[18] Outages citing the regulatory/safety/environmental cause code consist largely of wind turbine outages due to cold weather and icing.

GAS SUPPLY

Figure 18, Figure 19 and Figure 20 illustrate natural gas, wind and coal generation that were unavailable Feb. 1-20 due to forced outages, distinguished by the associated cause as submitted in CROW. On average, approximately 72% of all forced gas generation outages experienced during the week of the event were caused by fuel-supply issues.

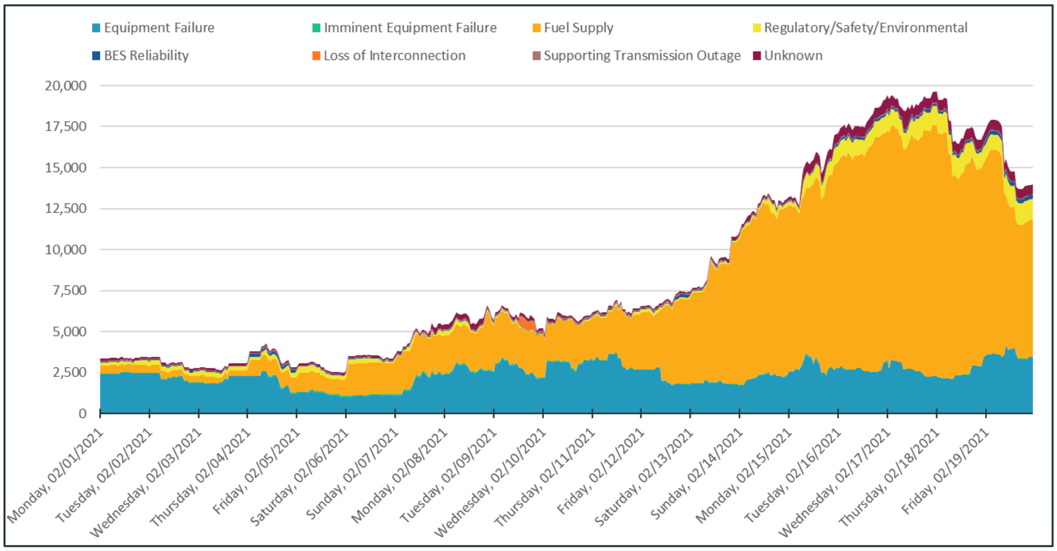

Figure 18: Forced natural gas generation outages as submitted in CROW by Cause Code

On average, approximately 51% of all forced wind generation outages experienced during the week of the event were caused by regulatory/safety/environmental issues, with 90% of those related to icing conditions.

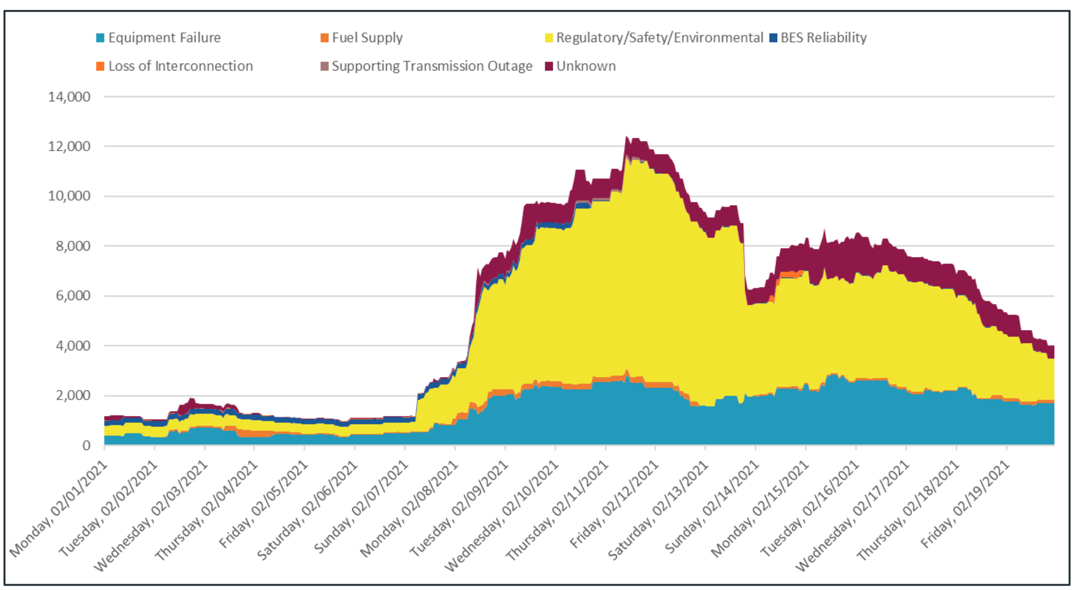

Figure 19: Forced wind generation outages as submitted in CROW, by Cause Code

On average, approximately 43% of all forced coal generation outages experienced during the week of the event were caused by equipment failure with another 28% caused by fuel-supply issues.

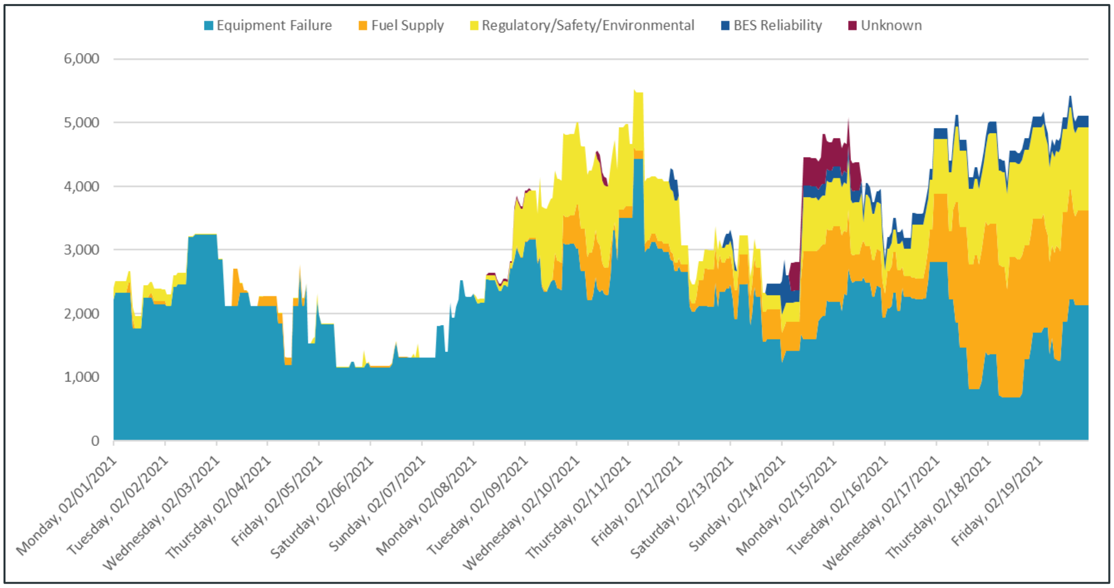

Figure 20: Forced coal generation outages as submitted in CROW, by Cause Code

GRID-SWITCHABLE RESOURCES

During the winter event, SPP coordinated with ERCOT regarding the use of grid-switchable resources that can operate in either SPP or in ERCOT. Three such resources are considered accredited capacity in SPP. These resources were committed and used as available to supply SPP load during the event when necessary to prevent service interruptions Feb. 15 and Feb. 16. SPP allowed the resources to supply load in ERCOT during times when they were not needed in SPP.

MUNICIPAL GENERATION, DEMAND RESPONSE AND BEHIND-THE-METER AVAILABILITY

There were municipal generators not directly connected to the SPP transmission system that were capable of operating but did not run during the event. SPP, as the BA, does not have a complete picture of all resources that may be available to assist during an energy emergency, and as a result some resources did not assist where needed. SPP did issue appeals to members to identify any resources not in the market that could assist with supplying load, but some were still not notified to come on-line.

CONCLUSIONS REGARDING FUEL ASSURANCE

The generating resources most impacted by the 2021 winter weather event were those fueled by natural gas.

Similar to electric power, the available natural gas fuel for consumption by electric generation and other customers is limited by the capacity of the supplies and transportation provided by the gas pipeline system. Extreme cold weather experienced across the SPP region resulted in natural gas procurement and deliverability issues. Increased demand for natural gas to heat homes combined with production issues attributed to wellhead freeze-offs resulted in a lack of access to natural gas by generator operators.

Upon review of information provided by the SPP Market Monitoring Unit (MMU), it is clear that extremely high natural gas prices were the primary driver of record high energy offers that exceeded the Federal Energy Regulatory Commission (FERC)-required offer cap of $1,000/megawatt-hour (MWh) for the first time in SPP's market history. On Feb. 15, SPP's market price reached an all-time high of $4,274.96/MWh in the day-ahead market (DAMKT). By comparison, the average price of energy in SPP's DAMKT for the entire year of 2020 was $17.69/MWh. Natural gas markets are not subject to price or offer caps, while electricity markets like SPP's are.

It is important to note that the electric industry does not have the ability, nor should it have the responsibility, to ensure a reliable, resilient and affordable natural gas supply. It is incumbent upon the natural gas industry to make the changes necessary to improve the supply of natural gas during extreme weather events. It is imperative that regulators understand the limitations of the electric industry in improving natural gas supply. Any new requirements to improve natural gas supply need to be imposed upon the gas industry and not the electric industry if this situation is to be improved.

The lack of access to natural gas was the largest contributing factor to the severity of the event, and establishes the need for better coordination and communication between the gas and electric industries moving forward.

In particular, additional early communication of potential severe conditions and the forecasted high demand for natural gas could have provided both industries with useful preparation time.

SPP has made several improvements related to gas-electric coordination in the past five years. In 2015, FERC issued Order No. 809 "Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities." In response to the order, in October 2016, SPP shortened the DAMKT timeline by 30 minutes and shifted the closing and posting times earlier in the day. In May 2020, SPP further reduced the DAMKT timeline by an hour. In addition, between 2016 and 2018, SPP coordinated with market participants to increase awareness of the need for additional detail in outage reporting, particularly fuel issues. SPP also recently implemented a multiday commitment and pricing forecast, which should provide generation-owning market participants with additional information related to generation needs. SPP

continues to seek opportunities for gaining efficiencies that better align the DAMKT with the gas day.

While SPP has focused on communication between the RTO and the market participant, SPP believes there should be a focus on increased communication between the RTO and the gas industry, i.e., communicating the need for gas and any deliverability issues of gas. SPP also believes it is important to understand the impacts of the development of natural gas fueled resources on the gas industry. SPP also thinks it is imperative to coordinate new projects with the gas industry, with the goal being to either increase the RTO knowledge of gas resource availability or increase the availability of gas to those same resources.

Certain system conditions may result in severe impacts to the electric or gas infrastructure. Better coordination is needed between the electric and gas industries to identify potential infrastructure contingencies within the RTO that could have a large impact on gas generators within the SPP region. The SPP Balancing Authority (BA) Emergency Operating Plan (EOP) does not presently include procedures for assessing and analyzing gas infrastructure reliability impacts on the SPP region during severe weather events, capacity emergency procedures, significant pipeline maintenance outages, pipeline operational flow orders, or during any other applicable conservative operations event.

FUEL ASSURANCE RECOMMENDATIONS

Table 11: Summary of recommendations to the board related to fuel assurance

#	TIER	CATEGORY	RECOMMENDATION
FA 1	1	Policy	Develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region.
FA 2	1	Assessment	Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events.
FA 3	2	Policy	Develop policies to improve gas-electric coordination that better inform and enable improved emergency response.

RESOURCE ADEQUACY, PLANNING AND AVAILABILITY

Figure 21 illustrates generation capacity in SPP. Nameplate capacity reflects the maximum amount of energy that all generation in SPP can produce based on equipment ratings.

Accredited capacity is the amount of generation capability owned or purchased by entities in SPP responsible for serving load that is expected to be available to meet peak demand. Energy production reflects how much energy was actually produced by generating assets in SPP during the most recent year.

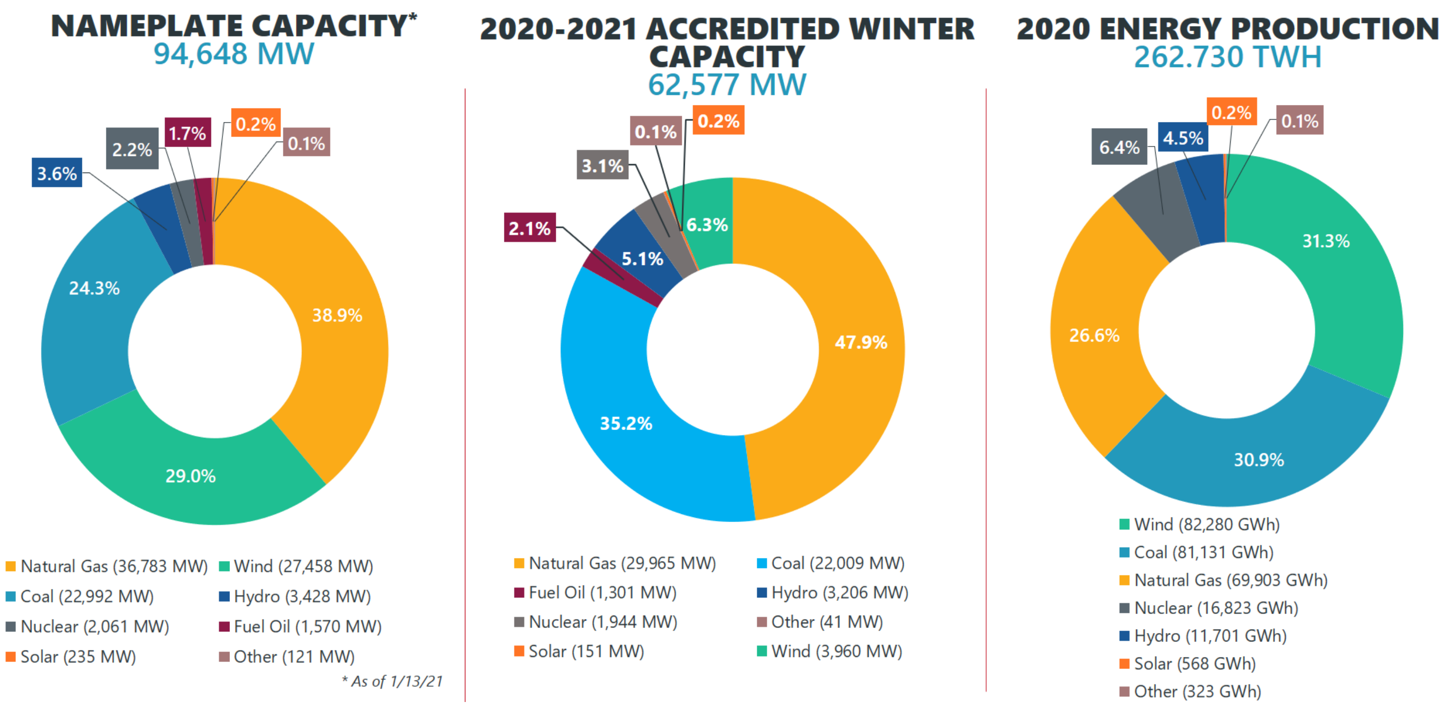

Figure 21: SPP generating capacity overview

During the periods on Feb. 15 and 16 when SPP declared an EEA 3, approximately 42% of nameplate capacity was available on average. The total amount of generation available during these time frames constituted approximately 65% of SPP's accredited capacity, with 87-88% of that available generation provided by accredited resources.[19]

[19] Each year, SPP verifies the specific amounts of each generating resource owned by load-responsible entities in SPP that are accredited for capacity purposes. During the event, generation available to SPP consisted of both accredited capacity resources and those that are not accredited. For these numbers, available generation represents the total economic maximum capability of online generation resources.

Figure 22 shows the status of generation capacity in SPP, distinguishing capacity that was on outage, unavailable and available. It also shows the used energy.

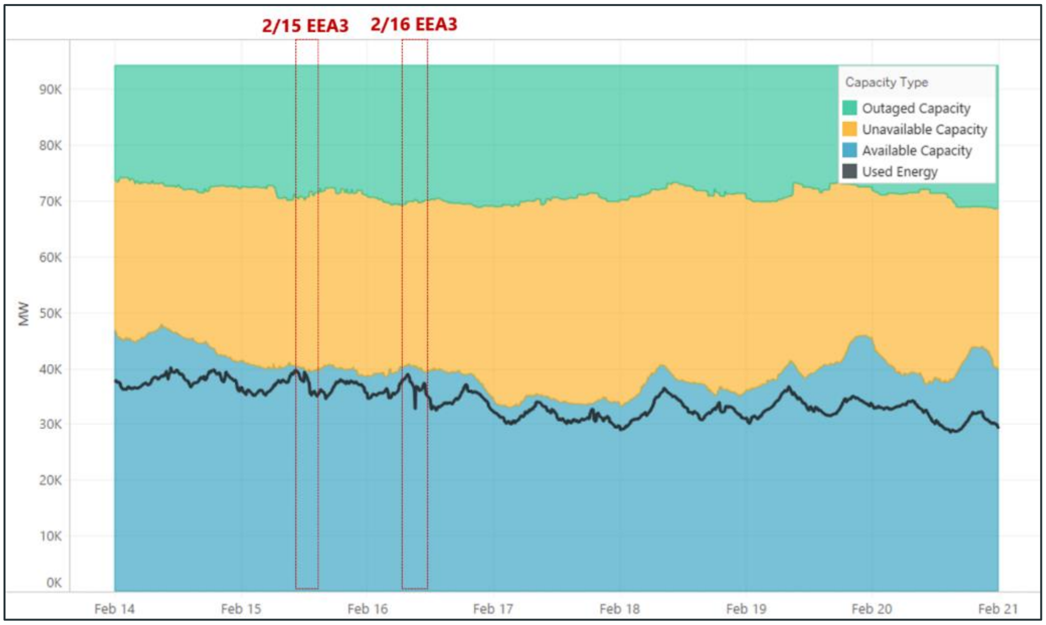

Figure 22: Total generating capacity in SPP

Considering only wind generation, 12-16% of nameplate capacity was available on average during the EEA3 events. The total amount of wind energy produced on average during these time frames constituted approximately 79-101% of accredited wind capacity, with 43-54% of that energy provided by accredited resources. This is illustrated below in Figure 23.

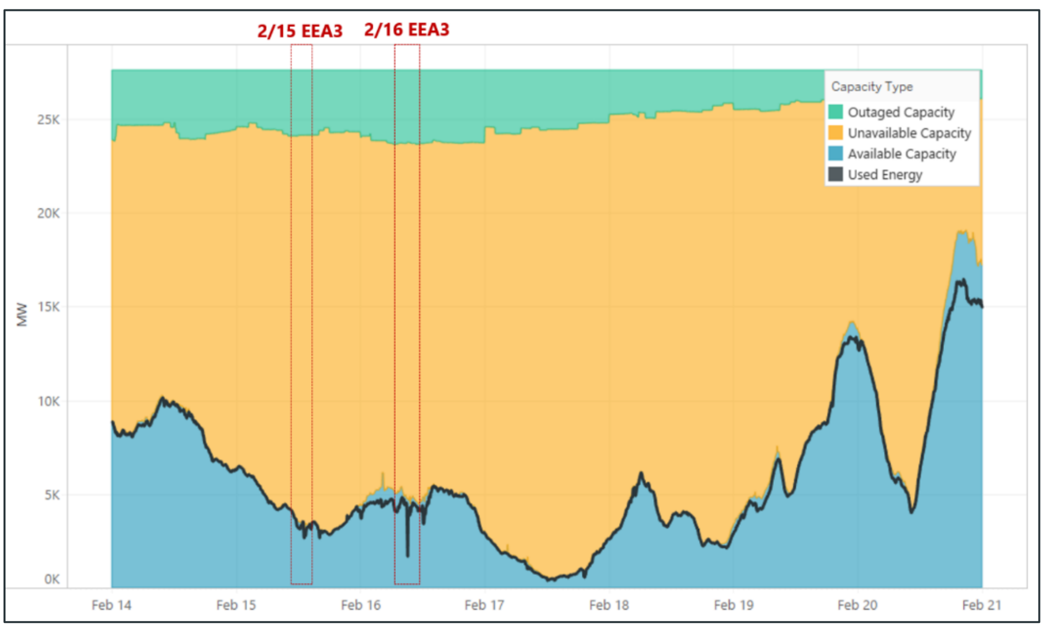

Figure 23: Total wind generating capacity in SPP

Regarding coal generation, about 77-79% of nameplate capacity was available on average during the EEA3 events. The total amount of coal energy produced on average during these time frames constituted approximately 87-89% of accredited coal capacity, with 98% of that energy provided by accredited resources. This is illustrated below in Figure 24.

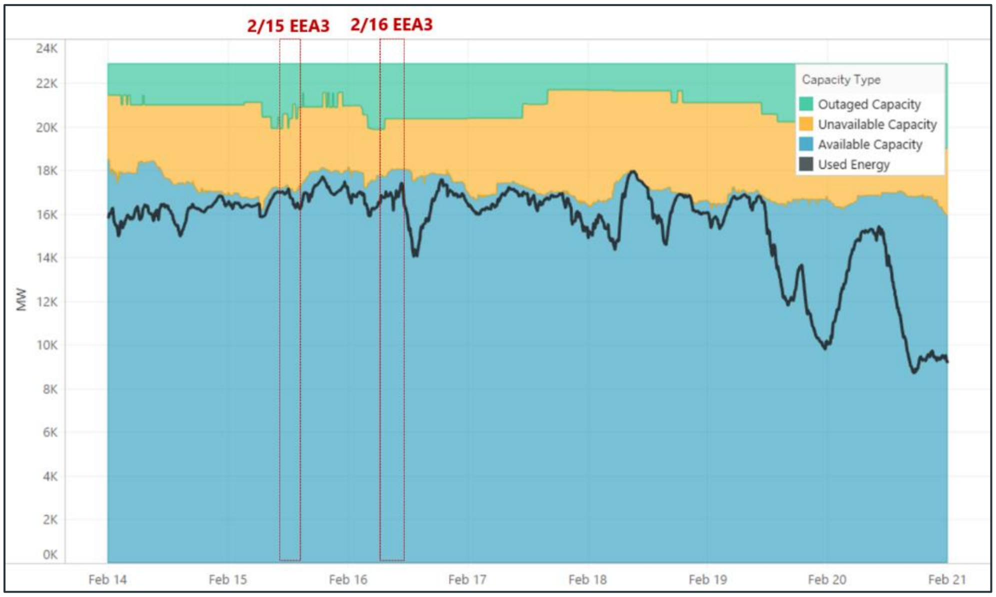

Figure 24: Total coal generating capacity in SPP

Regarding gas generation, about 34-37% of nameplate capacity was available on average during the EEA3 events. The total amount of gas energy produced on average during these time frames constituted approximately 40-45% of accredited gas capacity, with 95% of that energy provided by accredited resources. This is illustrated below in Figure 25.

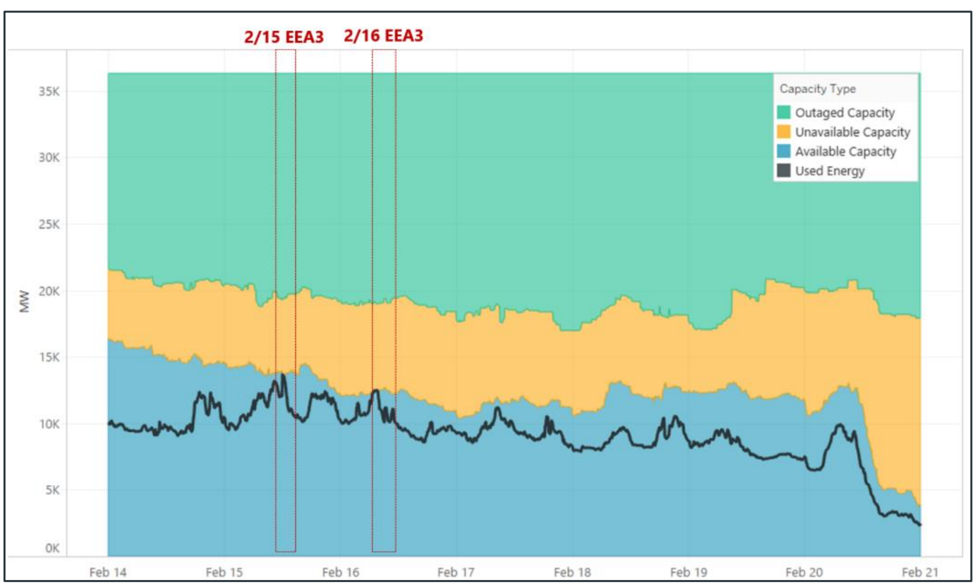

Figure 25: Total gas generating capacity in SPP

The following graphs compare available generating capacity with historical accredited capacity in February. The historical data set includes available generating capacity from each February of years 2014 through 2020. The shaded background indicates the total accredited amount of capacity that was applicable during February 2021.

The accredited value applicable to the 2020-2021 winter season is 62,577 MW for resources registered in the SPP market. The total accredited capacity used to meet resource adequacy requirements was 65,174 MW, which includes behind-the-meter generation not registered in the SPP market and firm imports to the SPP BA.

In the following graphs, available generating capacity for wind and solar is equivalent to the real-time dispatch amounts, while the generating capacity for all other fuel types relies on the real-time economic maximum limits for units that were not on outage. The economic maximum limit is the uppermost limit set in the resource market offer for which a resource can operate to without moving into emergency ranges.

Accredited capacity amounts used in these graphs are based on market resources only.

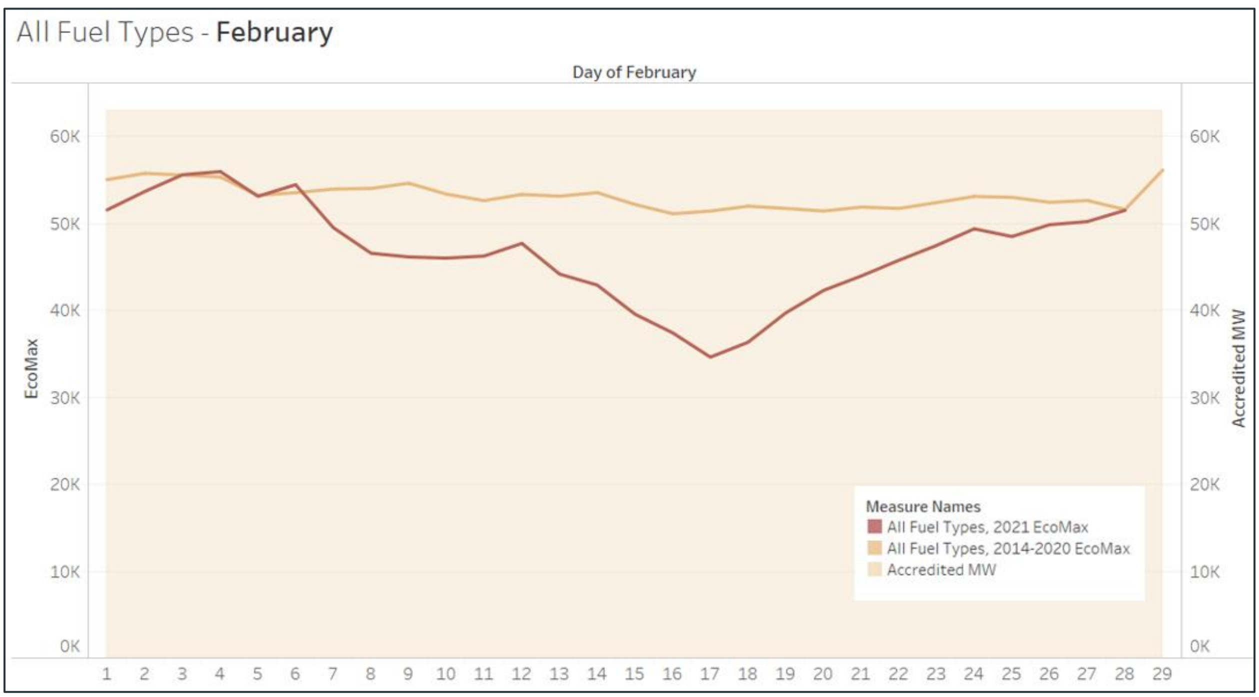

Figure 26: February 2021 available capacity as compared to prior year average

Wind availability was variable during February 2021. A significant icing event began Feb. 7, which contributed to the sharp decline in availability, as shown in Figure 27 below. Available capacity for wind is set to the real-time market dispatch of wind resources.

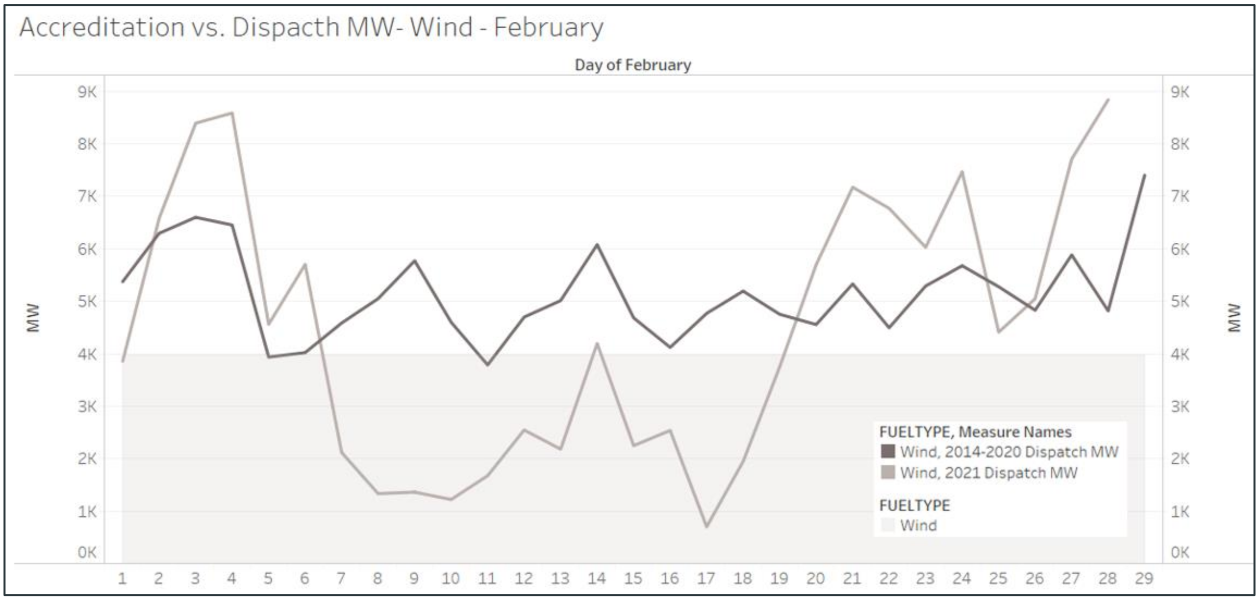

Figure 27: February 2021 available wind capacity as compared to prior year average

Coal availability for February 2021 fell roughly 2 GW below prior years. Available capacity for coal, shown in Figure 28, is based on the real-time economic maximum for units not on outage.

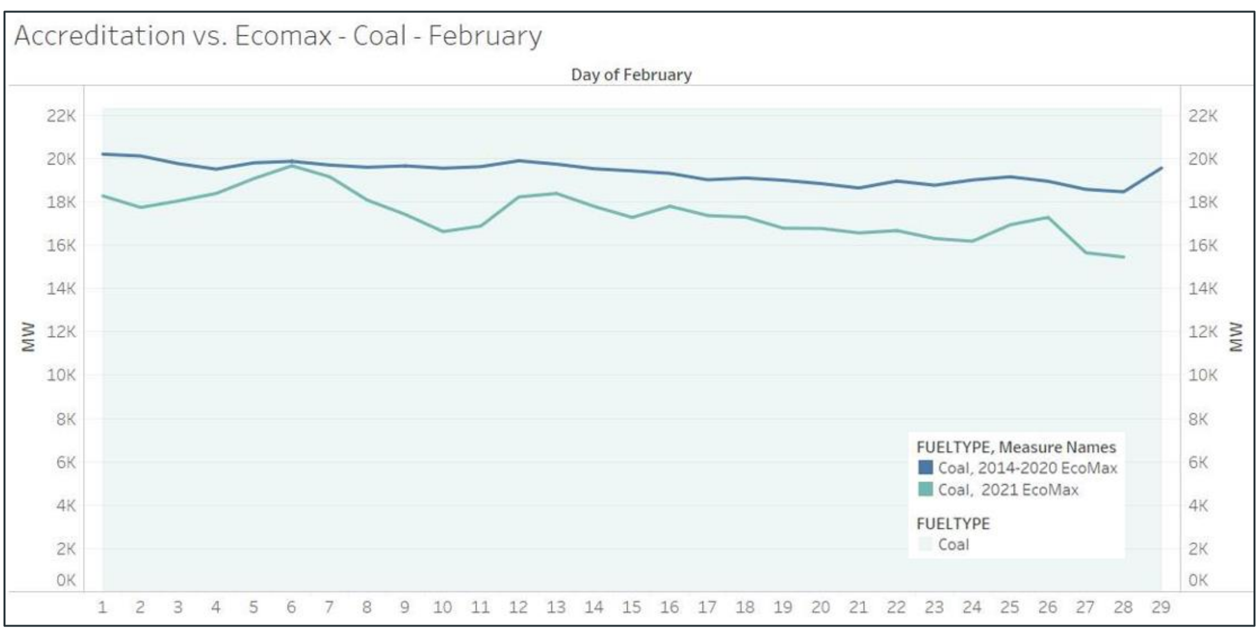

Figure 28: February 2021 available coal capacity as compared to prior year average

Gas generation availability dipped substantially during the week of Feb. 14. In Figure 29, available gas capacity is set to the real-time economic maximum for units not on outage.

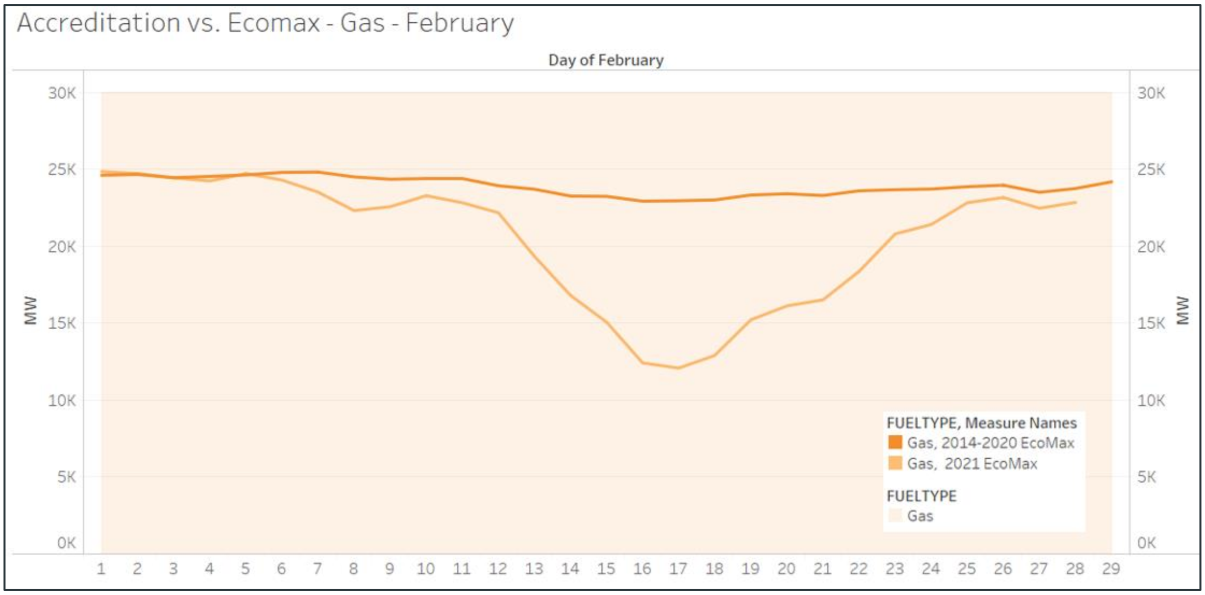

Figure 29: February 2021 available gas capacity as compared to prior year average

CONCLUSIONS REGARDING RESOURCE PLANNING AND AVAILABILITY

The 2021 winter weather event highlighted weaknesses of the components of the supply-side of the grid.

All forms of generation were stressed, and there were outages across all generation types. The event struck during a time of change in the way energy and capacity are supplied in the region. The event highlighted the need to further assess SPP's ability to reliably operate the system with the increased use of intermittent resources and further reduction of base-load resources. As the resource mix has changed and is expected to continue to evolve, the way resource adequacy has been determined in the past does not appear adequate to meet the needs of the future.

Accreditation values and capacity requirements based on summer assumptions do not adequately portray the amount of capacity that can be relied upon and needed during other critical seasons.

Summer peak assessments cannot accurately determine the needs of a severe event in the winter. Fuel supplies are under different constraints, wind and solar patterns are different, and the ability of a generator to start can vary markedly. Because of this, SPP needs to have a better understanding of the strengths and weaknesses of all resource types during times other than summer. SPP should also assess the importance of diversity in supply and demand resources

and how these resource types interact with each other during periods of stress and assess cost effective ways to ensure that reliability is able to be maintained. The 2021 winter weather event underlined the importance of this work.

Historically, data has shown the average economic max capacity for conventional resources in SPP's Integrated Marketplace is lower than the accredited capacity submitted for resource adequacy purposes. SPP and the SAWG have diligently worked over the past two years to begin implementing more robust and reliable accreditation methodologies across all resource types. This effort started with the implementation of the effective load carrying capability (ELCC) methodology for wind, solar and battery storage starting with the 2023 summer season.

Additionally, there is an effort underway to evaluate a form of performance-based accreditation for conventional resources. This important work should continue with extra emphasis and with focus on seasonal expectations.

Currently, SPP resource adequacy policies place an obligation on each load-responsible entity (LRE) to meet its individual winter season noncoincident demand plus the planning reserve margin (PRM) requirement. The winter season PRM is based on a Loss-of-Load Expectation (LOLE) study that is performed every two years and determines the appropriate amount of capacity needed to reliably maintain the one-day-in-10-year standard.

While this study encompasses the whole year, its focus is on the summer peak season, for which the majority of loss of load in the SPP region is analyzed to occur during the summer timeframe. Therefore, the PRM applied to the winter season is based on the summer season demand values. Expectations of abnormally excessive generation outages during extreme weather events (cold, heat, drought, flooding, atmospheric conditions) are not currently included in the planning study with a higher than previously experienced occurrence rate.

Currently, LREs that schedule planned outages during the summer season are not allowed to count that capacity toward their resource adequacy requirement. As risk of loss of load is seen to expand beyond the summer season into the winter season and potentially into the shoulder months, policies need to address how accredited capacity may be counted in the summer and winter seasons with planned outages taken into account.

RESOURCE PLANNING AND AVAILABILITY RECOMMENDATIONS

Table 12: Summary of recommendations to the board related to resource planning and availability

#	TIER	CATEGORY	RECOMMENDATION
RPA 1	1	Assessment	Perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix.
RPA 2	1	Policy	Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives, that ensure sufficient resources will be available during normal and extreme conditions.

EMERGENCY RESPONSE PROCESSES AND PLANNING

SPP's emergency response processes are detailed in the SPP BA Emergency Operating Plan (EOP)[20]. This plan includes procedures for issuance of load-shed instructions. Load shed is a controlled interruption of electric service to end-use customers under an EEA level 3 when all other means of supplying internal load have been exhausted, or to maintain area control error (ACE) so as to not jeopardize the reliability of the bulk electric system. Per the SPP Operating Criteria and Appendices[21], the Reliability Communications (R-Comm) tool is the primary means of communication for responsible entities to receive, acknowledge and carry out load-shed instructions issued by the SPP BA.

SPP staff performs load-shed tests regularly. SPP also conducts annual training for SPP operators on energy emergency alerts and load shed for the SPP BA, including the use of the R-Comm tool.

Each member transmission operator (TOP) is responsible for developing, maintaining and testing its own emergency response plan and for carrying out load-shed instructions pursuant to those plans.

LOAD SHED DURING SYSTEM CONGESTION

During load shed on Tuesday, Feb. 16, 2021, there were locations where generation was curtailed at the same time load was being shed on the same side of constraints. Considering that load shed can be considered a very expensive demand response unit, it may not be optimal to dispatch a high-cost unit up at the same time a lower-cost unit is being dispatched down in the same area. Pro-rata curtailments are reasonable when there is no congestion on the system but could lead to excessive load shedding during times when there is congestion on the system.

DISTINGUISHING BETWEEN FIRM AND NONFIRM EXPORTS

SPP did not distinguish between exports that were firm (associated with a capacity or firm energy transaction) versus nonfirm energy during the EEA. The North American Electric Reliability Corporation (NERC) Reliability Standard EOP-011-1 Attachment 1 identifies that during an EEA level 1, "Nonfirm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed." During the event, SPP treated exports pursuant to their transmission service priority only without regard to the firmness of the energy that was associated with the transaction. SPP needs procedures and processes that clearly identify that curtailment is based upon the transmission service level for transmission curtailments and based upon the level of firmness of the energy for EEAs.

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[20] Revision 7.5 (Effective 09/30/2020), https://www.spp.org/spp-documents-filings/?id=34055
[21] Revision 2.2 (Effective 06/17/2019), https://www.spp.org/documents/60100/spp%20operating%20criteria%20and%20appendices%20v2.2.pdf

EMBEDDED ENTITIES AND LOAD-SHED PROCEDURES

SPP did not have an accurate representation of which embedded entities were contained within various transmission operator (TOP) footprints. Additionally, some TOPs did not understand the load-shed amount they were given included the total load connected to their transmission footprint and not just their entities' load. As a result, some entities may have not been included in the load-shed event and other entities may have had incorrect amounts of load shed requested of them.

LOAD RATIO SHARE FOR LOAD SHED

The load ratio share used to determine each TOP's share of the manual load-shed amount is based upon prior year energy use for a season. Some customers were proactive and voluntarily reduced their demand for electricity in response to public appeals or as part of an interruptible load program. The current paradigm does not recognize the contributions to the entire SPP region that these reductions provide. One way to recognize these contributions would be to calculate load ratio shares used for load shed based upon actual loads at the time of the event.

LOAD-SHED INSTRUCTIONS

On Feb. 16, 2021, SPP initiated a load-shed event for 1,350 MWs of BA load followed by a second load-shed event for an additional 1,350 MWs of BA load 33 minutes later. The result was confusion by several TOPs who were unsure if they had received a second load-shed instruction, or a secondary notification of the initial load shed instruction. SPP staff noted that the separate instructions were accompanied by unique R-Comm event IDs. Although a partial load restoration was not necessary, SPP was prepared to use the load-shed calculator if the need arose. There is an R-Comm enhancement underway that would allow for systematic processing of partial load restoration.

INTERRUPTION OF CRITICAL LOAD

During the load-shed events, there were concerns from TOPs that natural gas compressor station loads may be curtailed, exacerbating the fuel shortage issue and causing a need for additional load shed.

There are additional concerns that these critical loads do not have adequate backup plans to continue operating in the event of a loss of interconnection to the grid such as gas fired compression. Reliance upon the electric grid to power compressors will lead to interruptions in service due to other forced outages not initiated by the TOP.

CONCLUSIONS REGARDING EMERGENCY RESPONSE PROCESSES AND PLANNING

SPP's and its members' emergency response processes, including use of load-shed procedures, were effective in preventing uncontrolled, more significant loss of load but could be improved to increase effectiveness and appropriateness of load-shed actions.

EMERGENCY RESPONSE PROCESSES AND PLANNING RECOMMENDATIONS

Table 13: Summary of recommendations to the board related to emergency response processes and planning

#	TIER	CATEGORY	RECOMMENDATION
ERP 1	2	Assessment	Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations.
ERP 2	2	Action	Implement improvements to load shed processes to be developed by the Operating Reliability Working Group (ORWG), such as: • Utilize real-time load values when determining load-shed ratio shares. • Train and drill on multiple overlapping load-shed instructions. • Perform a detailed review of models used to determine load-shed ratio shares. • Develop and document procedures and processes to address the timing and responsibility of curtailing exports before and during a load-shed event.
ERP 3	2	Policy	Develop a policy to ensure TOP emergency response and load-shed plans have been reviewed, updated and tested on an annual basis to verify their effectiveness, with attention to critical infrastructure.

OPERATOR TOOLS, COMMUNICATION AND PROCESSES

During Feb. 15 and 16, 2021, there were constraints loaded above 115% of their emergency ratings post-contingent. SPP has processes that instruct staff to perform a cascading analysis for post-contingent loading levels above 115%. Although this is good practice, the results of these analyses are not available for TOPs for review.

When SPP issues out-of-merit-energy (OOME) instructions, there is not a consistent method to inform SPP real-time operations personnel when conditions have changed that will permit the release of all or part of the OOME instruction. In addition, there were locations where low-cost resources were manually dispatched down at the same time high cost resources were brought online at the same BUS.

There were times when the market was unable to solve congestion due to the violation relaxation limit (VRL) being less than the cost to move resources. This was exacerbated by an increase in the maximum energy price, but when the market doesn't have enough resources to balance load with resources and interchange and resolve congestion, the congestion will remain. It may be beneficial in the long run to identify pockets where load reductions would be the least costly to resolve congestion once the congestion has not been corrected for several market iterations. In addition, it may not be readily apparent to TOP operators the Market Clearing Engine (MCE) is not respecting this constraint because the cost to solve the congestion is greater than the VRL.

The R-Comm tool performed well throughout the event. Communications were timely and the information provided to the TOPs via R-Comm was timelier than other methods of communications. Especially when messages require acknowledgement, there is a high degree of confidence the message will be received. When R-Comm was originally rolled out, there were concerns TOP operators may not pay attention to the messages that were sent over R-Comm alone. This event demonstrates that R-Comm is an effective mechanism for real-time operations communications between SPP and its TOPs. At times, the additional blast calls and satellite phone calls served as more of a distraction rather than an enhancement of the communications process. These communications mechanisms can serve as a backup means of communication, but are not needed when R-Comm is functional.

While TOPs have avenues to view some SPP systemwide data, the paths are disjointed, and the data available does not provide a complete system overview. Offering TOPs a single tool that provides a complete system overview would help TOPs better understand the state of the SPP region in real time. Additionally, conservative operations alerts can have many different interpretations, ranging anywhere from business as usual to TOPs canceling and recalling outages. Associating conservative operations alerts with defined alert levels would give more meaning to the conservative operations alerts and help members react to the alerts accordingly.

The pre-event calls between SPP and the Operating Reliability Working Group (ORWG) members provided valuable communications on the situation unfolding. There were others in SPP who could have benefited from this information, and SPP could have benefited from others having this information firsthand. However, there was no readily available contact list that SPP could

utilize to quickly organize a conference call. Furthermore, it would be advantageous for SPP to develop email lists that utilize distribution lists developed by each operating entity for different types of notifications. SPP needs to identify whether each group may contain merchant employees or not. This will be determined by the type of information sent to each list. Having the entities maintain internal distribution lists with SPP just sending information to a single list, will place responsibility and control of who receives the messages within the membership. This may result in more up to date distribution lists.

CONCLUSIONS REGARDING EMERGENCY RESPONSE PROCESSES AND PLANNING

SPP's tools, communications and processes were largely effective during the winter weather event but should be improved to increase effectiveness and awareness among critical participants.

OPERATOR TOOLS, COMMUNICATION AND PROCESS RECOMMENDATIONS

Table 14: Summary of recommendations to the board related to operator tools, communications and processes

#	TIER	CATEGORY	RECOMMENDATION
OTCP 1	2	Action	Develop or enhance the tools, communications and processes identified by the ORWG and needed to improve SPP and stakeholder response to extreme conditions, such as: • Enhance real-time cascading analysis studies and post results. • Develop tool(s) to increase operator awareness of Out of Merit Energy (OOME) instructions. • Enhance and expand the use of R-Comm.[22] • Create a reliability dashboard to improve situational awareness for operators. • Utilize member-maintained distribution lists for communications purposes. • Develop a process to update operations management during extreme conditions.

[22] R-Comm is the Reliability Communications tool, the primary means of communication for responsible entities to receive, acknowledge and carry out load-shed instructions issued by the SPP Balancing Authority.

MARKET DESIGN

PRICING DURING EEA EVENTS

PRICE RESPONSIVE LOAD AND PRICING DURING LOAD-SHED EVENTS

During the Feb. 15 and 16 load-shed events, SPP observed intervals during which locational marginal prices (LMPs) dropped below $100. These lower LMPs may have sent the wrong signal to the market during a time when energy was needed so the load could be restored. The price formation and incentives for continued energy delivery may be improved during these times by modifying the pricing structure during load-shed events to continue to reflect prices associated with serving the desired amount of load and not the reduced amount of load due to the load shed. Incentives for price-responsive load in SPP's market may also improve the price formation during these times by allowing the market to determine load reduction based on offers and congestion.

VIOLATION RELAXATION LIMITS AND DEMAND CURVE PRICING DURING EMERGENCY CONDITIONS

During the event, SPP also observed instances where transmission constraint violations occurred due to energy offer prices exceeding the VRL price. Energy prices offered above the highest VRL price can overpower the cost to re-dispatch around transmission constraint that leads to these violations. The current VRL prices were set based on analysis using the FERC approved $1,000 energy offer cap. However, during the 2021 winter weather event or other emergency conditions when energy offers are greater than $1,000, these VRL prices may not be appropriate.

SPP also observed violations on the spinning reserve requirement and resource ramp rate constraints. Spinning reserve and resource ramp rates are priced as VRLs. These VRL prices may not provide transparent prices during events such as the 2021 winter weather event. SPP may desire to change these two requirements to be demand curves instead of VRLs, but this also means SPP must determine the appropriate price for these demand curves.

APPLICATION OF EMERGENCY LIMITS

During the 2021 winter weather event, system conditions dictated SPP release maximum emergency capacity operating limits in accordance with the prescribed language in both the Integrated Marketplace Protocols and Attachment AE of the SPP Open Access Transmission Tariff. This release of maximum emergency capacity operating limits allowed for DAMKT dispatch values up to these limits for a number of resources, including some VERs. Additionally, while the DAMKT used emergency capacity operating limits as prescribed by the governing documents, in real time, emergency capacity operating limits were not used due to operational concerns. This raises the question as to whether or not the application of maximum emergency

capacity operating limits is appropriate and provides the value SPP and the membership envisioned during the design of the Integrated Marketplace.

DAY-AHEAD MARKET AND MARKET-TO-MARKET

One purpose of SPP's DAMKT is to give generators and LSEs a means by which to schedule activities sufficiently prior to their operations. This is typically based on a forecast of their needs and consistent with their business strategies. Although SPP committed many resources for reliability reasons, rather than through the usual DAMKT process, the DAMKT continued to give reasonably accurate predictions of the operating day. The exceptions were Feb. 13 and 14, 2021, which SPP repriced after-the-fact.

While the DAMKT looks ahead and the market-to-market process focuses on real-time, they are traditionally both views as tools to further enhance economic benefits of the Integrated Marketplace, not to enhance reliability. During the 2021 winter weather event, their reliability benefits were evident. By committing resources through the DAMKT process, it reduced the dependency of capacity generation being required to be committed through the reliability unit commitment processes. During the event, this was critical, as it was even more vital to the overall capacity needs to the SPP footprint to ensure all available generation could be utilized appropriately.

Similarly, the market-to-market process's ability to use the combined generation fleet of both SPP and MISO to mitigate constraints further displayed its reliability benefits. The process allowed for a more systematic response than the alternative methods such as transmission loading relief (TLR). It also provided a mechanism for increased real-time communication on how mitigation of internal RTO constraints with internal generation would impact the neighboring RTO's constraints.

MULTIDAY RELIABILITY ASSESSMENT

SPP's Integrated Marketplace design consists of numerous unit commitment processes beginning with the multiday reliability assessment (MDRA), continuing with the DAMKT and concluding with the day-ahead, intraday and short-term reliability unit commitments (RUC). The purpose of the MDRA is to evaluate the reliability-based need to issue instructions to start to resources that cannot be committed in the day-ahead RUC because of their long lead time as well as committing resources as part of conservative operations, as outlined in the SPP BA EOP.

As part of conservative operations, SPP issued resource commitments of various lead times well in advance of the DAMKT to give early notice that the resources would be needed and to allow more time to procure the appropriate amounts of fuel needed for the duration of the event. Although similar commitments have been made as part of conservative operations in the past, the scale during this event was unprecedented and has allowed SPP to assess the processes, procedures and governing language associated with the MDRA process.

DISTPATCH TARGET ADJUSTMENT PROCESS

During the 2021 winter weather event, the SPP BA activated an operational tool downstream from the Real-Time Balancing Market (RTBM) clearing called Dispatch Target Adjustment (DTA). This tool lives in the emergency management system (EMS) application RTGEN. The DTA tool is typically used by SPP operations to balance the SPP region in times when the MCE is not functioning properly or not working at all.

During the 2021 winter weather event, the SPP BA used the DTA process to ensure its ability to balance the region and keep ACE in check due to insufficiencies in cleared operating reserves from the RTBM and due to uncertainty around the timing of curtailed tags from MISO. Notably, the RTBM cases continued to solve and approve, publishing new dispatches and LMP every five minutes. DTA takes the last solved and approved RTBM and adjusts the resulting setpoint as needed to chase the load using the marginal cost calculated in that RTBM. While the setpoint adjustments were generally in merit and updated as RTBM cases approved, there were many instances where resources were positioned out of merit and financially harmed.

MARKET DESIGN RECOMMENDATIONS

Table 15: Summary of recommendations to the board related to market design

#	TIER	CATEGORY	RECOMMENDATION
MKT 1	2	Policy	Develop and improve policies to ensure price formation and incentives reflect system conditions.
MKT 2	2	Action	Develop and implement market design and market related enhancements identified by the Market Working Group to improve operational effectiveness and ensure governing language provides needed flexibility and clarity, such as: • Improve the Dispatch Target Adjustment Process. • Enhance the Multiday Reliability Assessment Process.
MKT 3	2	Policy	Develop policies to ensure financial outcomes during emergency conditions are commensurate with the benefits provided.

TRANSMISSION UTILIZATION AND PLANNING

CONGESTION

Congestion describes a condition when usage of transmission facilities exceeds reliable operating limits. SPP and neighboring areas experienced very high levels of congestion during the winter event. Congestion particularly posed challenges, as an abnormally high number of transmission system constraints[23] experienced high loading. Many constraints were as much as 10-20% above their post-contingency operating limits, and some were near real-time operating limits. Primary contributors to system congestion during the focused period of Feb. 15-19 included, but are not limited to:

- Winter peak load levels.
- High import flows from neighboring systems into SPP.
- High export flows into ERCOT from SPP including schedules using firm transmission.
- MISO regional directional transfer flow at times in excess of the 3,000 MW north-to-south contractual limit.
- Unrecallable transmission outages.
- Congestion and operational challenges in neighboring systems.

Mitigation methods utilized to manage system congestion included, but are not limited to:

- Market redispatch.
- Out-of-merit-energy (OOME).
- Transmission Loading Relief (TLR).
- Post-contingent load shed plans.

Table 16 shows some mitigating actions that occurred Feb. 15-19. Market breached/bound transmission constraints indicate those for which SPP was actively trying to redispatch generation as a mitigation method. Only SPP member-owned constraints are included and, as these are daily counts, one constraint may recur multiple days. OOME counts include each unique resource instruction (e.g., an OOME cap issued for a resource at 100 MW and later reduced to 50 MW will be reflected as two OOMEs). TLRs are those issued by SPP. For reference, the 2016-2020 daily average number of OOMEs issued on any day in February is less than one,

[23] Transmission system constraints are transmission elements or groups of elements that limit or constrain distribution of electricity due to necessary imposition of reliable operating limits. Constraints are sometimes referred to by the industry as "flowgates."

and the daily average number of breached/bound constraints for the same time periods is 15.3 constraints.

Table 16: Daily mitigation summary (Feb. 15-19)

DAILY COUNT ITEM	FEB. 15	FEB. 16	FEB. 17	FEB. 18	FEB. 19
Market Breached/Bound Constraints	43	54	22	19	24
OOME	25	41	4	9	10
TLR	2	1	0	0	0

Figure 30 shows the number of SPP member-owned constraints that were overloaded during each hour Feb. 15-16. The sharp drop in the number of overloaded constraints that occurs after 7 a.m. Feb. 16 is due in part to SPP system load shed. Certain constraints may fall into multiple overload categories for a particular hour. The chart captures all instances of constraint loading in each category and does not necessarily indicate that loading persisted at high levels for the entire hour. For example, a constraint that was loaded at 105% for 20 minutes and loaded at 115% for 10 minutes would be captured in both the >100% and the >110% categories for a given hour.

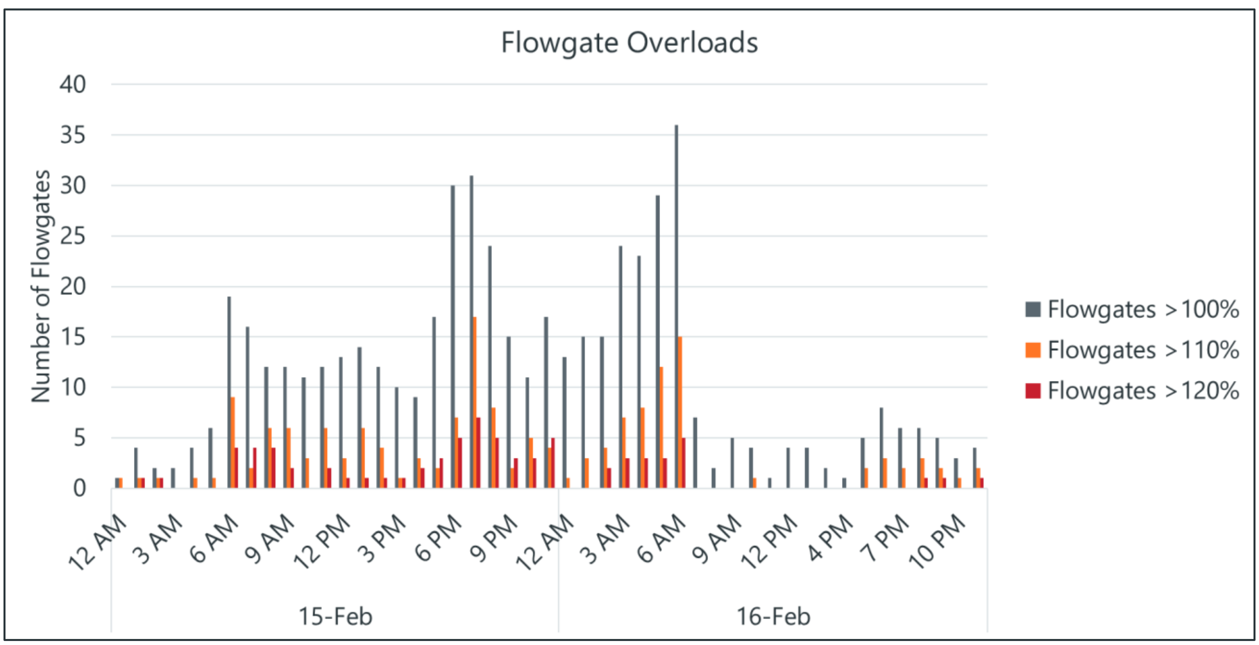

Figure 30: Hourly constraint overloads (Feb. 15-16)

Constraints loaded at or above 115% post-contingent are considered 'severely loaded.' These constraints are analyzed further by real-time staff to determine if they pose a potential risk to

the interconnection. Analysis includes running contingency analysis studies with both the monitored and contingent facilities removed from service to look for cascade type situations. During Feb. 15-19, real-time contingency analysis (RTCA) identified several constraints loaded over 115% post-contingent. The specific regions captured Figure 31 were particularly subject to severe loading.

Region	Flow Direction	Contributing Factors	Primary Reliability Concerns	Mitigation Actions
Western Kansas	NW → SE (into SPP)	• Heavy imports into SPP • 345 kV line outage	• Real-time overloads • Potential loss of load pocket • Low voltage	• OOME • Post-continent load shed plan
Eastern Nebraska Eastern Kansas	NE → SW (into SPP)	Heavy imports into SPP	Potential for widespread issues for the loss of 345 kV path	• TLR • OOME
Western Kansas	E → W (into SPP)	• Heavy imports into SPP • 500/161 kV transformer outage	• Potential voltage collapse in northern Arkansas • Real-time overload on 500 kV line	• TLR • OOME
Eastern Texas	E → W (into SPP and ERCOT)	• Heavy imports into SPP • Area generation trip	• High post-contingent loading in SPP • MISO concerns due to real-time overloads • Low voltage	TLR

Figure 31: Regional overview of severe loading

INTERCHANGE WITH NEIGHBORING ENTITIES

During the event, SPP observed the highest level of imports into its market since it went live in March 2014. SPP reached total imports of higher than 7,500 MW during the event and reached a total net scheduled interchange of more than 6,000 MW of imports. These imports were needed to help SPP meet demand and reserve obligations throughout much of the event. Figure 32 shows exports and imports by firm and nonfirm status for Feb. 10-20.

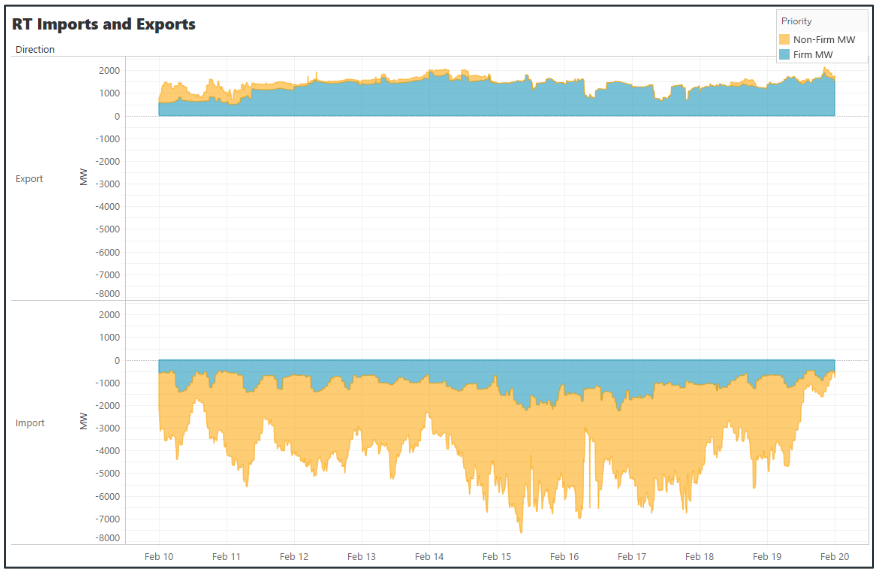

Figure 32: Real-time imports and exports by status (Feb. 10-20)

Curtailment of imports was a key factor in the necessity to shed load on both Feb. 15 and 16. Figure 33 provides a closer look at real-time imports and exports during critical time periods.

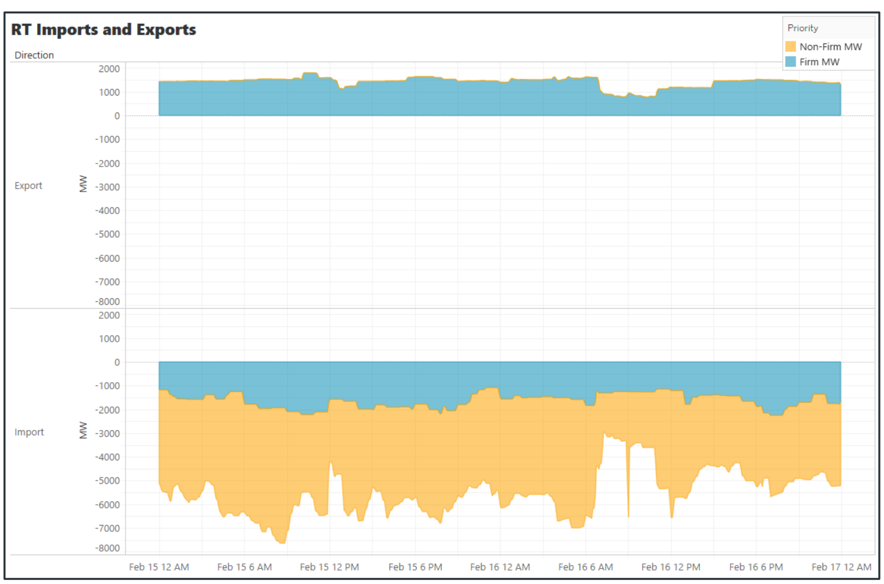

Figure 33: Real-time imports and exports by priority (Feb. 15-17)

The following figures illustrate SPP's net interchange with the remainder of the eastern interconnection during load-shed timeframes. On Feb. 15 (Figure 34), TLR curtailments effective at 12 p.m. reduced energy imports into SPP. Once energy imports were restored, SPP could instruct load restoration.

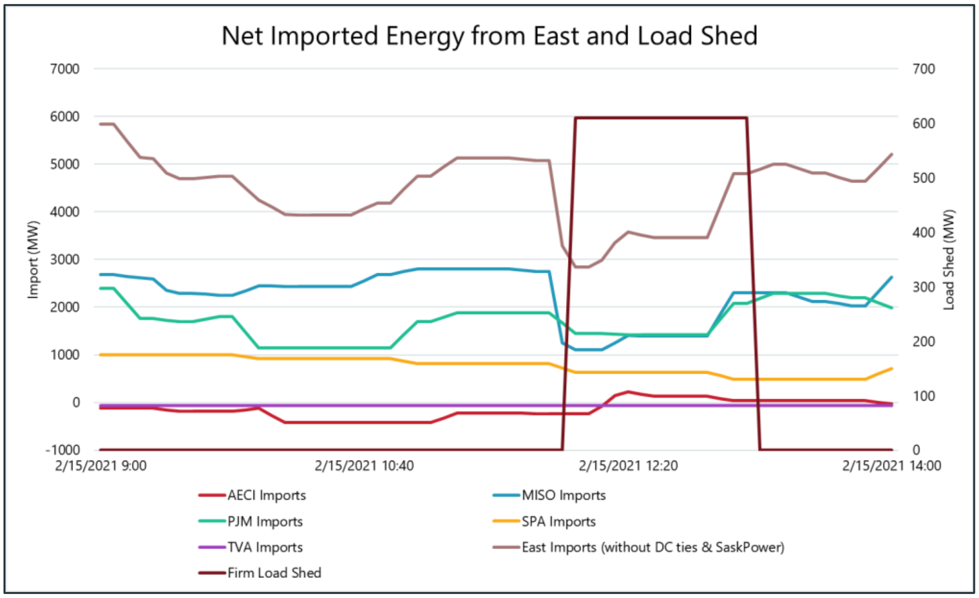

Figure 34: Eastern Interchange (Feb. 15, 2021)

As illustrated in Figure 35, on Feb. 16, schedule curtailments effective at 7 a.m. reduced energy imports into SPP. The sudden spike in imports that appeared shortly after 8:30 a.m. was the result of an inadvertent schedule adjustment during execution of the curtailments that was quickly corrected.

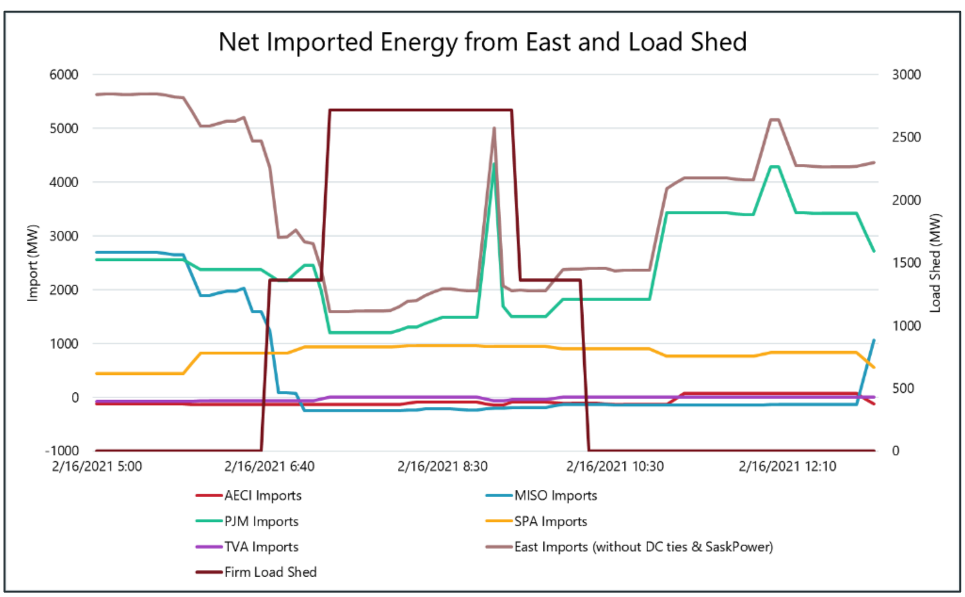

Figure 35: Eastern Interchange (Feb. 16, 2021)

WESTERN INTERCONNECT TIES

Seven DC ties connect SPP to the Western Interconnection. During the winter event, four of the seven ties were in service. The three ties that were not operable were out of service in advance of the winter event on scheduled outages. Figure 36 shows flows across the operable DC ties during Feb. 15-16. Negative values indicate flows into SPP.

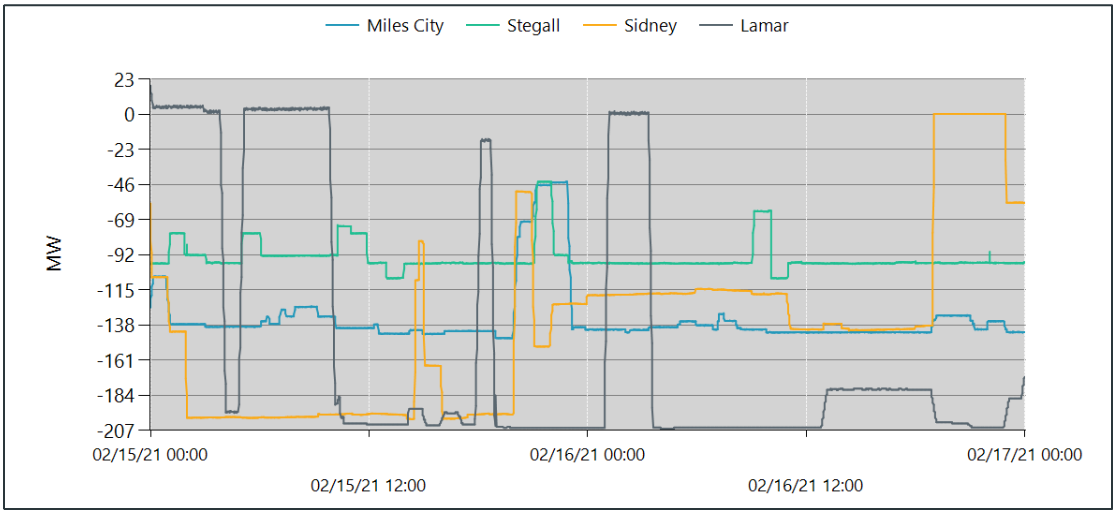

Figure 36: West DC Tie Summary

ERCOT TIES

Two DC ties connect SPP and ERCOT. Both were in operation during the winter event. Figure 37 shows flows across the ERCOT DC ties Feb. 15-16. Positive values indicate flows into ERCOT. At times, ERCOT DC ties were reduced due to curtailments associated with EEA 3 conditions in SPP and TLR curtailments from IDC due to congested constraints.

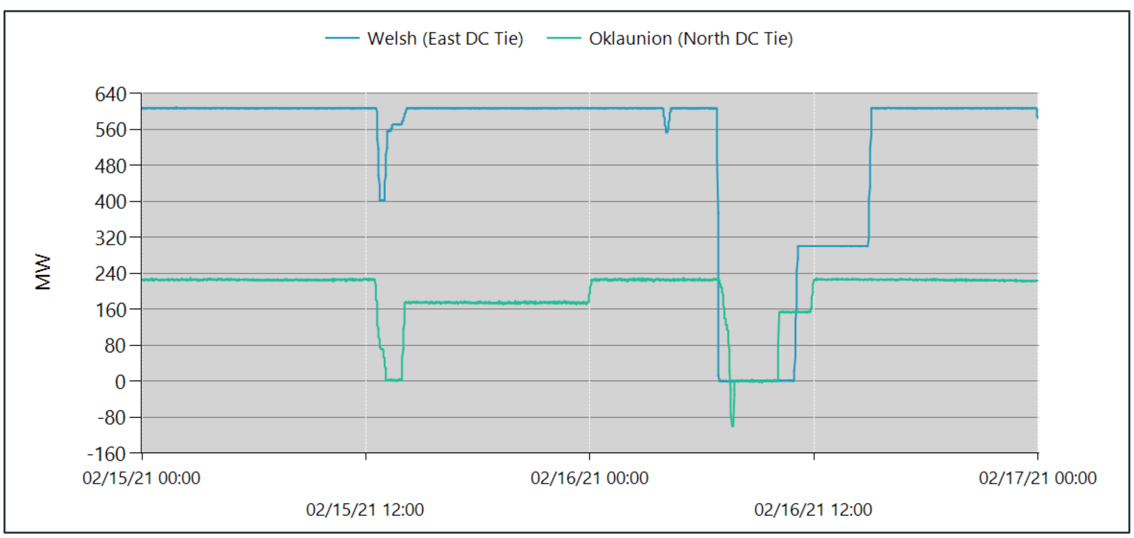

Figure 37: ERCOT DC Tie Summary

SASKPOWER PHASE SHIFTER

SaskPower (Saskatchewan, Canada) connects to SPP through a phase-shifting transformer. This tie was used to import power into SPP during the winter event. Figure 38 shows flows across the SaskPower phase shifter Feb. 15-16. Negative values indicate flows into SPP.

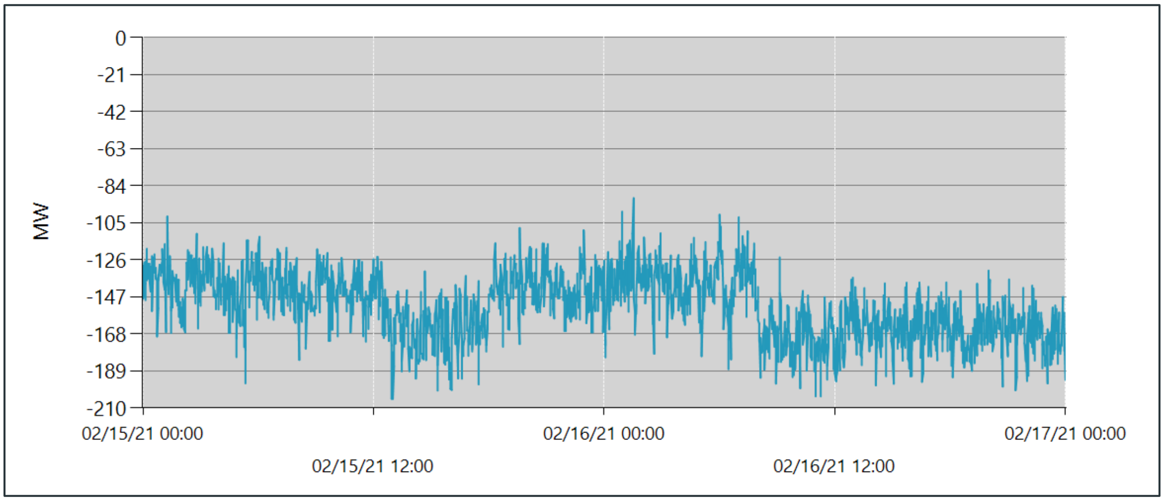

Figure 38: SaskPower Phase Shifter Flow

CONCLUSIONS REGARDING TRANSMISSION UTILIZATION AND PLANNING

Adequate transmission to deliver power is critically important in decreasing the impact of future extreme conditions, provides added resilience and could mitigate the need to implement load-shed procedures.

Although severe congestion was experienced at times during the 2021 winter weather event, significant investments that have been made over the last 10-15 years to upgrade the SPP transmission system allowed SPP to more fully utilize the generating resources that were available. SPP also was able to rely on capability of the broader transmission network to import significant amounts of energy from its neighbors. Transmission, both within and outside SPP, proved critical and beneficial in avoiding longer controlled interruptions of service.

Future evaluations of transmission needs should consider impacts of severe events.

This increased transmission utilization during the event pointed to the importance of appropriately assessing the deliverability of a dispersed set of resources across the Eastern Interconnection during such times. The event and congestion that existed also highlighted that SPP should improve efforts in the transmission planning study processes to evaluate adequate transmission capacity needed during normal and emergency conditions. Other forms of energy and an increased focus on improving the transmission system are critical to decrease the

possibility of further controlled interruption of service to customers. The 2021 winter weather event is a credible scenario that needs to be adequately scrutinized to understand potential impact of such events and protect against as SPP plans for the future (gas unavailability and the inability to meet demand with intermittent resources).

TRANSMISSION PLANNING RECOMMENDATIONS

Table 17: Summary of recommendations to the board related to transmission planning

#	TIER	CATEGORY	RECOMMENDATION
TXP 1	2	Policy	Develop policies that facilitate transmission expansion needed to improve SPP's ability to more effectively utilize the transmission system during severe events.
TXP 2	3	Policy	Develop transmission planning policies that improve input data, assumptions, or analysis techniques needed to better account for severe events.

SEAMS AGREEMENTS AND EMERGENCY ASSISTANCE

The SPP market relies on price signals to incent market participants to submit import interchange transactions when energy supply becomes limited. However, there may be situations where these commercial import interchange transactions are insufficient for the SPP BA to maintain adequate operating reserves and SPP must initiate an EEA in accordance with NERC Reliability Standards. Assistance from neighboring BAs and RTOs may need to be relied upon to provide emergency energy during these situations.

SPP had seams agreements with each of its neighbors during the winter weather event, but those agreements had inconsistent provisions regarding the exchange of and compensation for emergency energy. SPP relied heavily on imported energy provided by neighboring entities during the event, including from those with whom SPP has a seams agreement.

Certain agreements require that the requesting entity be in an EEA Level 2 or higher, that the emergency energy be formally requested, and that the amount (MWs) and duration be coordinated. As specified in these agreements, emergency energy transactions are intended to continue only until they can be replaced by normal commercial transactions. The rates and charges associated with these emergency energy transactions include a transmission charge and an energy portion.

Other agreements contain provisions specifying expectations for sharing emergency energy but do not specify payment terms. When emergency energy is provided pursuant to those

agreements, the provider is subject to prevailing market prices. The lack of specific payment terms in these agreements denies those providers certainty that they may recover costs associated with providing emergency energy. Lack of certainty could dis-incent the provision of available emergency assistance in the future.

CONCLUSIONS REGARDING SEAMS AGREEMENTS

During the 2021 winter weather event, SPP relied heavily on emergency assistance it received, but the inconsistent terms and provisions in current seams agreements create uncertainty going forward and should be addressed.

SEAMS AGREEMENTS RECOMMENDATIONS

Table 18: Summary of recommendations to the board related to seams agreements

#	TIER	CATEGORY	RECOMMENDATION
SEAMS 1	2	Action	Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance and fairly compensate emergency energy.

ANALYSIS OF FINANCE, SETTLEMENTS AND CREDIT

Extreme cold, increased electricity use, high price of natural gas and limited generation resulted in dramatic price increases across SPP's Integrated Marketplace footprint. SPP experienced historically high market settlements for the impacted operating days: $16.3 billion have been settled for Feb. 13-19. Figure 39 shows the sum of payments made to (MP Credits) and collected from (MP Charges) market participants (MP) from August 2020 to June 2021. The dramatic spikes in the invoice totals are due to the high prices during the event's operating dates.

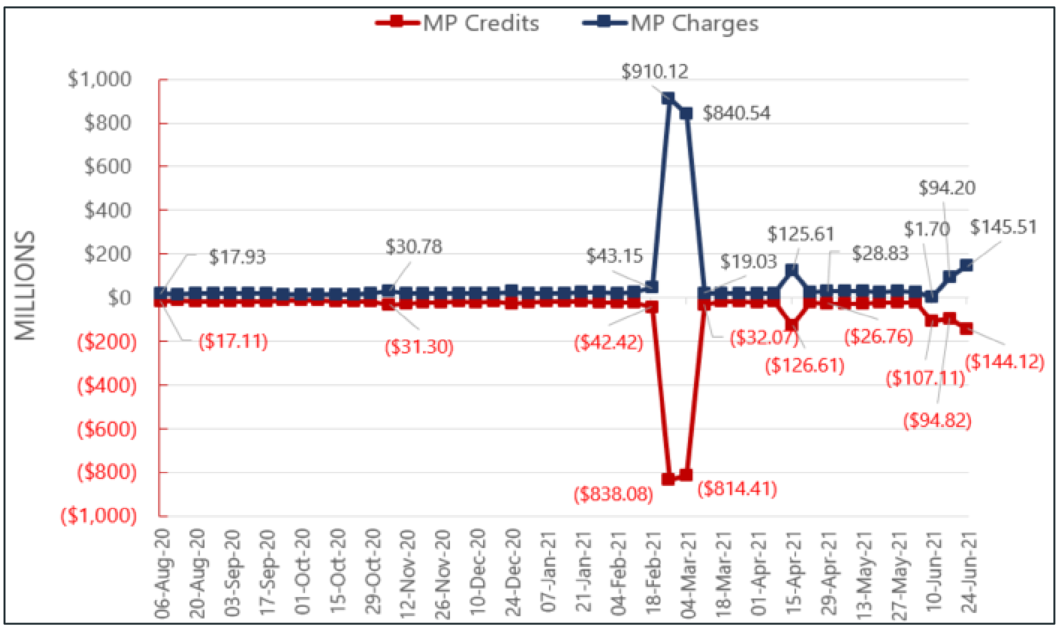

Figure 39: Weekly Marketplace Invoice Amounts (August 2020-June 2021)

Note: The June 10 invoice included the yearly ARR/TCR closeout dollars paid out on the last day of the planning year (May 31).

COST OF ENERGY

74% of settlement dollars ($12.13 billion) were due to various energy product charge types. Energy settlement dollars are paid to resources for injecting energy into the market and collected from load for consuming it. Prices were much higher than the typical averages for February. Due to the emergency status of the RTO and the need to find as much generation as possible, the DAMKT was committing all available units. In some cases, uneconomical units were committed, which resulted in high prices and led to a larger than normal volume of commitments in the DAMKT compared to the real-time balancing market (RTBM).

ORDER 831 – OFFER CAPS

SPP implemented tariff and system changes to comply with FERC Order 831. The order requires that each resource's incremental energy offer be capped at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer, as well as capped verified cost-based incremental energy offers at $2,000/MWh. Energy offers over $1,000 must be approved by the Market Monitoring Unit (MMU) before the start of the market (DA, RUC and RTBM).

SPP and the MMU filed a joint waiver with FERC to adjust the timelines for submission and verification of final costs and to align timing of deadlines with the anticipated timing of when generators would receive their final gas invoices.

MAKE-WHOLE PAYMENTS (MWP)

14% of total settlement dollars during the event were the result of make whole payments (MWP) to generators to make them whole to their costs (offers) in the market. A total of almost $880 million was paid out to resources that supplied energy in the DAMKT during the impacted days. That amount was funded by MPs with energy withdrawals in the DAMKT. An additional $220 million in MWP was paid in the RTBM to make generators whole to their real-time energy provided. RT MWP are funded by cost causers: virtual offers, deviations between day-ahead and real-time market for loads and imports/exports, and generators that deviate in real time.

SETTLEMENTS

Settlement calculations are performed for each operating day using the data available at that time. In addition to the three 'standard'[24] settlement postings, resettlements can be scheduled *as needed* following the S120 settlement posting for a given operating day. An MP may dispute items included in a settlement statement (or invoice) according to the following criteria established in the tariff/protocols.

There was a significant increase in settlement disputes as a result of the event. Many of the disputes were expected to be resolved with the posting of the S120 settlements. Some have already been granted upon verification that the issues were resolved.

MARKET PARTICIPANT CREDIT

The event created credit requirements never before seen for many of SPP's MPs. Market participants who were net purchasers of energy during the event experienced significant post-event collateral liabilities. The severity of energy prices could have potentially created a liquidity

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[24] Standard settlement postings occur seven, 53 and 120 days after the operating day. These are referred to as the S7, S53, and S120 postings

crisis in the energy market and caused some participants to default on collateral calls or payment obligations. FERC approved a waiver extending the timing of collateral calls, which assisted load-serving utilities with capital management.

The event also exposed many MPs to payment of significantly higher natural gas invoices than normal and their accompanying collateral requirements from suppliers. Some participants were simultaneously exposed to neighboring energy markets that also experienced sustained and severe price spikes.

SPP's credit policy (Attachment X of the tariff) reacted aggressively to sudden and extreme energy price increases. By design, it assumes that swings in trading volumes and/or energy prices indicate sustained trends. Market participants with extremely high energy invoices were also required to post collateral to ensure future payments could be made. Many collateral requirements significantly outran the unsecured credit allowances granted by SPP.

During the event, the MMU calculated that virtual energy participants made $400 million in the market. The MMU expressed that had prices "gone the other way," SPP's market may have been exposed to credit/payment defaults from some of these financial-only participants.

Total potential exposure (TPE) calculations for day-ahead and real-time energy were ineffective in dealing with the short-term, temporary price spikes. The TPE would have required temporary collateral postings up to five times higher than actual invoice liabilities, inconsistent with the specific event risk. FERC's waiver effectively helped maintain liquidity, assuming all load-serving entities paid their invoices in full and on time.

Virtual reference prices may have undervalued credit risk during scenarios where actual DA/RT variances were greater than the reference prices used for credit exposure calculations. The extreme pricing experienced during the 2021 winter weather event may also have an adverse impact on the calculations of virtual reference prices for first quarter 2022.

DATA ISSUES

A number of factors had an impact on the data provided to settlements. There have been no identified issues with the settlement calculations, only the upstream data provided to the settlement system for use in the calculations:

- **Multiday reliability commitments:** A software error incorrectly locked in resources from Feb. 13 through Feb. 14. Software changes allowed offers to be updated starting Feb. 15, but analysis found this change did not completely fix the issue.
- **Day-ahead reprice:** Original DAMKT results for operating days Feb. 13 and 14 were not accurate as a result of commitments and prices based on MDRA offers, rather than updated offers. This caused prices to be much lower than if correct offers were used and impacted the day-ahead quantities awarded.

- **Order 831 offer caps:** As a result of MMU-verified offers pushed for Feb. 13 and 14 (due to the MDRA software error), some previously settled MWP were clawed back in the S120. For Feb. 15-19, the majority of offers were not approved before the market closed, and S120 MWP increased as offers were verified and approved by MMU.
- **Other data issues:** SPP was in a dispatch target adjustment (DTA) anytime an EEA 2 or above was declared. Unlike previous usage of DTA, the market continued to solve in these instances. Some resources were moved counter to the offer provided to the market. The decision was made to settle DTA time periods as out of merit energy.

EMERGENCY SCHEDULES

Four neighboring entities submitted emergency schedules to provide assistance to SPP during the event. The majority were settled via the normal settlement process, with some limited manual adjustments via processes outlined in SPP's seams agreements.

SPP ACCOUNTING

SPP utilizes automated clearing house (ACH), a form of electronic funds transfer that settles usually the day after a transaction is initiated to pay MPs on a weekly basis. SPP also uses ACH to debit the accounts of those MPs owing SPP for their market invoices and who have elected to have such amounts drawn from their accounts by SPP. Due to the next-day-settlement nature of ACH payments, banks impose limits on their customers for ACH transactions to mitigate their credit risk. The event resulted in the total amount of weekly market ACH payouts and ACH receipts being exponentially larger than SPP's ACH limits with its bank for a two-week period in March.

SPP'S PERFORMANCE OF FINANCIAL FUNCTIONS

The new settlements system enabled SPP to be efficient, flexible, collaborative and proactive during the settlement of the winter event operating days. The efficiency of the new system, including the ability to process and validate manual data files to address data issues in real time, provided a means to deliver financial data to other departments and to the officer team quickly for consideration in the decision-making process.

SPP's credit department was able to use this data to research and analyze various scenarios that might have resulted in potential credit default events. As a result, staff filed a waiver request approved by FERC to extend the collateral call timeframe to help ensure liquidity in the energy market during the event. Staff was able to coordinate with all of the significantly affected utilities to provide data for their capital management and to ensure payments were made in full and on time.

As soon as SPP's ACH issue became known, staff reached out to and regularly updated its bank to explain the event and to alert them about the issue with the upcoming large ACH

transactions. SPP and the bank were able to temporarily switch to an ACH process called ACH secured funds, resolving limit issues and ensuring MPs received their payments on the regular payment due date. All transactions cleared on time with no problems and with no adverse or unexpected impacts on MPs.

CONCLUSIONS REGARDING CREDIT AND SETTLEMENTS

MDRA commitments resulted in data scenarios that are not typically seen in the market. In many cases, the tariff does not provide clear language with regard to how SPP systems should treat these scenarios. There should also be consideration given to where the tariff is lacking and what additional language is needed to avoid similar data issues should there be another weather event that impacts the SPP footprint.

Some scenarios encountered during the event weren't addressed in the original 831 compliance filing. SPP and the MMU will collaborate to understand these impacts and potential need for future changes to the tariff language, market processes and settlement calculations.

SPP should consider changes to the language filed with FERC regarding cost submissions and verification timelines. The timeline outlined in the tariff is not feasible in instances like those experienced during the event. SPP may also consider working with FERC to establish possible changes to capping levels based on the emergency status of the RTO.

The current design of the market allows for participation of non-asset owning MPs or financial-only participants. In some cases, these financial-only MPs benefited greatly from these events. Further analysis should be conducted to determine if these payments are appropriate and if the current design of the market is sufficient.

CREDIT AND SETTLEMENT RECOMMENDATIONS

Table 19: Summary of recommendations to the board related to credit

#	TIER	CATEGORY	RECOMMENDATION
CR 1	2	Assessment	Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in 1Q'22.
CR 2	3	Assessment	Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes.
CR 3	3	Action	Clarify tariff language related to SPP's settlements and credit-related authorities and responsibilities.

ANALYSIS OF COMMUNICATIONS

Throughout the February 2021 winter weather event, SPP used a number of communication channels to keep members and public throughout its service territory apprised of changing grid conditions. Operators followed clearly defined protocols for coordinating with member utilities.

In its analysis of communications before, during and immediately after the event, the Communications Comprehensive Review (CCR) team sought to identify ways to improve the accuracy, timeliness, reach and overall effectiveness of future emergency communications. To do so, they conducted several analyses and gathered input from several specific stakeholder audiences.

First, the CCR team evaluated the timeline and content of written communications during the week of Feb. 14-20. This review helped the team identify where messaging could have been clearer, where the sequence of communications activities was either helpful or problematic, why some messages were timelier than others and whether the appropriate audiences received the right information at the right time.

Second, the team conducted surveys of specific stakeholder groups to gauge their assessment of SPP's storm-related communications. The team surveyed:

- Members of the Regional State Committee (RSC) and Cost Allocation Working Group (CAWG), and representatives of SPP's member and market participant companies, to gauge the overall effectiveness of SPP's emergency communications.
- SPP's officers and directors to assess the time they spent communicating with individual stakeholders during the winter storm and to identify opportunities to make more effective use of leadership resources during emergency events.

Third, SPP staff and stakeholders conducted interviews with television, radio and newspaper journalists who reported on SPP's activities during the winter storm. The team sought to learn whether SPP's public relations activities during the winter storm were effective and appropriate.

Fourth, SPP facilitated discussions with stakeholders to learn more about the impacts of SPP's communications activities. Over a series of virtual meetings, the CCR explored stakeholders' experiences and emergency response activities, sought context for SPP's event data, and identified lessons learned and best practices that could be applied in future emergencies.

Lastly, the CCR team reviewed the effectiveness of SPP's public communications tools: SPP's website, social media channels, press releases and email distribution lists. Staff reviewed and shared SPP's website analytics, including up and downtime, traffic and frequently visited pages; social media analytics regarding the reach and engagement of storm-related posts; and reports of newspaper, web, television and radio coverage of SPP's storm response.

Overall, SPP's stakeholders were satisfied with and felt appropriately informed by SPP's emergency communications efforts. SPP's surveys of stakeholders showed strong ratings of the effectiveness of SPP's communications, a majority of respondents agreed that SPP's communications increased their trust in the organization's credibility.

There were, however, opportunities to improve communication practices for future emergency events. Before the cold weather event, SPP's communication and updates to members was beneficial and helped prepare the members for the event. Once the event began, the need for frequent communication increased, as did the size and complexity of SPP's audience.

SPP and its members and other stakeholders can improve communications by working together to improve communication with broad audiences and to clearly delineate communications roles during emergency events. A coordinated communication effort can reach all critical audiences with the information they need to take appropriate action and to reduce misunderstanding. A summary of the CCR's findings is included below, and more detail is available in their full report published on SPP.org.[25]

TIMELINE OF COMMUNICATIONS

Beginning Feb. 4, 2021, SPP issued several weather alerts, conservative operations declarations and emergency energy alerts. Figure 1, provided in the section labeled Events of Feb. 4-20 shows the times each of these alerts was declared.

Each of the following sections examines the timeline of SPP's communications with different audiences related to these operational events.

OPERATIONAL COMMUNICATION

Operational communication differs from other types of communication because it is almost exclusively between SPP operations and member company operations staff. This operator-to-operator communication happens daily under normal operations but was thrust into the public eye during the winter weather event.

SPP used R-Comm for the majority of its operational communications. Other communication channels used were email, phone calls and the Open Access Same Time Information System (OASIS) an internet-based information and scheduling system for electric power transmission services.

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[25] "A Comprehensive Review of SPP Communications during the Feb. 2021 Winter Storm: Analysis and Recommendations"

CONCLUSIONS REGARDING OPERATIONAL COMMUNICATION

When examining operator-to-operator communication, the team looked at many data points including survey results, analysis of the existing energy emergency alert (EEA) process and comments and feedback from operational staff.

SPP worked with members' corporate communications departments to issue public appeals on Sunday, Feb. 14 to reduce load on days following. The timing allowed customers to be aware and appeared to significantly reduce load compared to forecast during the highest load periods. The North American Electric Reliability Corporation (NERC) Attachment 1 of EOP-011-1 does not recommend public appeals to reduce load until a balancing authority reaches an EEA level 2. Issuing public appeals does require some time to make the appeal and for customers to respond. It seems more reasonable to have an appeal issued in advance of the event when possible.

SPP and nonoperational stakeholders should routinely drill load-shed and other procedures to prepare for future events. SPP should encourage consistent assessment, updates and testing of member emergency plans and communication with attention to critical infrastructure.

Stakeholders felt SPP should have provided earlier operator notifications to individuals in member organizations outside of operations staff. They should create an operational event early notification process, using R-Comm, OASIS or other operational system alerts, for key stakeholders. During long events, SPP operations should provide interim updates to member company operations staff.

Before the cold weather event, SPP's communication and updates to members were beneficial and helped prepare the members for the event. Once the event started, communication between SPP and the members reduced. Increased communication during these time would help the members' operations staff understand the current situations and what is needed.

If operational system alerts are utilized for nonoperations staff and the public, SPP should develop talking points, graphics and other materials that simplify and explain these alerts for broader audiences.

SPP should designate dedicated subject matter experts for communication during events.

STAKEHOLDER COMMUNICATION

SPP used various platforms to reach stakeholders, including alerts from its emergency communication tool, xMatters, emails to exploders and distribution lists, daily webinar briefings, social media and website updates.

Beginning Feb. 14, SPP issued press releases and alerts about the winter weather event and its impact on system conditions. These notices continued throughout the week to inform

stakeholders and customers of changing conditions, concluding with an alert issued Feb. 19 noting that SPP had ended its EEA1 state and returned to conservative operations.

Daily briefings were also held with stakeholders throughout the week of the event. These daily briefings helped communication efforts tremendously. The briefings helped members communicate with their end-users and equipped them with consistent language, resources and materials to explain the event to public audiences.

Additionally, SPP officers hosted calls with members, reached out to individuals and provided open and direct lines of communication.

SPP's communication efforts were greatly helped by the years of preparation staff had done before the event to build relationships with member communication staff. This included an annual testing of its emergency communication system, developing contact lists and hosting annual communication conferences.

CONCLUSIONS REGARDING STAKEHOLDER COMMUNICATION

While there were many things that SPP did well when communicating with stakeholders, the CCR identified areas for improvement.

More preparation is needed ahead of any future events. SPP should reassess who receives emergency alerts and tools for updating contacts. They should consider defining a "calling tree" procedure that clearly assigns responsibilities for communicating with specific audiences and implement a process to regularly update contact lists.

Many stakeholders felt communication should have been earlier and more varied. SPP should identify opportunities to send members notices about more alert levels and provide more detailed event information to points of contact identified at each organization. SPP should consider more effective and frequent communications on other aspects of the event, including market and repricing activities.

There are many efforts SPP and member companies can do together to improve communication to stakeholders, including coordination of press releases and media briefings. The planning of media briefings should be done with members and local utilities with enough time for them to coordinate their own local press briefings as a follow-up. They should also work to develop educational materials that explain SPP's and members' load-shed procedures or responsibilities.

GOVERNMENT AFFAIRS AND REGULATORY COMMUNICATION

As conditions started to deteriorate, SPP staff alerted member company government affairs representatives, the SPP Regional State Committee (RSC) and Federal Energy Regulatory

Commission (FERC) staff about worsening conditions in our footprint. This was done in a variety of ways through emails, phone calls and webinars. SPP also sent emails to U.S. congressional offices as well as governor offices and state energy offices across the SPP region, apprising of changing conditions throughout the week of the event.

CONCLUSIONS REGARDING GOVERNMENT AND REGULATORY COMMUNICATIONS

SPP identified opportunities for improvement when communicating with government affairs staff and regulatory officials.

Early in the storm, SPP included government relations staff on communications to member company communication staff. This helped to ensure messaging was getting to the right individuals. In the future, SPP should examine additional opportunities for collaborative communication between SPP's government affairs and regulatory teams and consider including member government affairs and regulatory staff earlier and on more notifications.

Contact list management impacted SPP's ability to reach government affairs and regulatory representatives. Some lists were outdated due to election-related turnover. SPP may more frequently update contact, improve contact-update processes for public officers, or consider tools to allow self-updates.

More frequent joint calls and webinars with the RSC, CAWG, member government affairs and regulatory staff and elected officials would ensure more consistent communication and address some concerns from stakeholders who felt communication to these groups was insufficient. SPP should have clear emergency points of contact for RSC and other public officials, and examine opportunities for rapid notification of certain alerts from operations to commissioners.

SPP should develop educational materials and resources about SPP, RTO/TOPs and energy emergencies for government affairs and regulatory staff, state commissioners, congressional offices and governors' offices. Staff should look for opportunities to remind officials of the benefits of RTO services in event communications.

PUBLIC COMMUNICATION

During the winter weather event, SPP distributed nine press releases and provided 10 informational updates regarding grid conditions. These were sent to various groups including stakeholders, news release exploder subscribers, media outlets with whom SPP had developed relationships, member company communication staff and posted to www.spp.org. When possible, member company communication staff were given previews of releases to create consistent messaging.

SPP communication staff received an influx of media inquiries at the onset of the event. In addition to our regular media contacts, we received inquiries from a large number of small, local news outlets across the footprint. The most inquiries came from Oklahoma, but all SPP states were represented. We also received inquiries from media outside the footprint.

It quickly became apparent the request load was too large to respond to all inquiries individually. At that point, SPP decided to host daily press briefings. SPP held three daily "State of the Grid" briefings for news media and stakeholders with 924 attendees across three days. These livestreams were broadcast by some affiliate networks, and recordings of each briefing were posted on social media.

SPP saw increased traffic on its website. After the first EEA3 was declared Feb. 15, SPP experienced rapid increases in website traffic, slowing or interrupting site access for some users. These spikes in traffic often followed social media posts, especially about EEAs or impending outages. Due to the increased traffic, SPP created a grid conditions page where current alerts, definitions of alert levels and a timeline with each new event were posted.

Throughout the storm, SPP posted updates to Twitter, Facebook, LinkedIn and Instagram. The first post to social media about the storm was the Feb. 14 press release. Between Feb. 14 and Feb. 20, 42 Twitter tweets, 24 Facebook posts, 23 LinkedIn posts and 18 Instagram posts were made.

On Twitter, SPP gained 5,479 followers and had 3.5 million engagements with posts. On Facebook, SPP gained over 12,000 page likes and had over 160,000 engagements.

Facebook engagement escalated quickly, peaking Feb. 15 and began to decline Feb. 16. Twitter impressions peaked quickly and declined more slowly. LinkedIn and Instagram had far fewer engagements than Facebook or Twitter.

SPP communications posted five videos during the winter weather event, including the three recordings of the "State of the Grid" news briefings and two "explainer" videos. The explainer videos were titled "Who is Southwest Power Pool?" and "Why was power interrupted during this storm?" and featured SPP officers. These video postings resulted in 8,800 views, totaling over 1,000 hours, and 139 new YouTube subscribers.

CONCLUSIONS REGARDING PUBLIC COMMUNICATIONS

SPP gained invaluable insight from managing social media during the winter weather event that will help navigate social media platforms in the future, both during normal operating circumstances and emergencies.

During a multiday event, day one is the most critical time to engage social users. Spikes in engagement are short-lived, and SPP should use these temporary increases in engagement to their advantage to reach as many people as possible. SPP should focus on using the most effective platforms, and SPP received the most engagement on Twitter and Facebook. In the

future, SPP should utilize Twitter and Facebook for real-time notifications since they provide the most engagement. Graphics that explain the status of the grid and what to do will get high engagement. To combat negative sentiment scores, SPP can change messaging to better empathize with end-user challenges and combat misinformation by collaborating with news outlets and members.

Because there was limited engagement on LinkedIn and Instagram, it may not be worth the time to monitor and create real-time content for these platforms during emergencies. These platforms may be better utilized for post-event information or pre-event educational materials. Since Facebook proved to be the greatest driver of traffic to videos, SPP should prioritize video sharing on that platform primarily.

SPP received positive feedback on both the daily briefing and explainer videos. While the explainer videos received more views than videos posted under typical circumstances, the recordings of the daily "State of the Grid" briefings were the most watched. Audiences wanted to know who SPP is, but they wanted to know what was happening more. In light of this information, SPP should consider promoting daily briefing information on social media platforms before they begin. SPP can better utilize video in emergencies by preparing videos in advance for a public audience that are tailored to emergency events.

SPP staff interviewed four reporters from a local newspaper, local public radio, industry publication and a local TV station anchor to gather feedback on its communication with media. This audience represented a variety of media outlets and covered the majority of the SPP footprint. Each of the reporters indicated they got their news from a mix of sources including SPP's social media, emails from SPP, its website and communication with member companies and would likely continue to use a variety of sources in the future. All reporters said they would benefit from educational and other related materials posted on the SPP website before the event or sent in conjunction with press releases.

In the wake of the storm, there may be demand for direct education from SPP to news media, and SPP should consider an annual media day in collaboration with members to educate the public on who SPP is, who are their members are, the benefits they provide and how they work together to protect the grid.

SPP received such a flood of media requests at the onset of the winter weather event that the "State of the Grid" press briefings became critical for responding to media and providing public updates. While feedback from media told SPP these briefings were helpful, SPP should consider a mix of morning and afternoon briefings to better meet the needs of the different types of reporters.

SPP's media briefings were often livestreamed by local news outlets. Knowing this, SPP should work to create messages tailored for the public, and ensure speakers receive proper media training. To reach a broader audience at briefings, SPP can improve promotion of briefings and its news distribution sign-up process.

The electric industry is complex, and information regarding the status of the grid can be difficult to communicate. This event highlighted the need to improve public emergency communication. Press releases should use clear, simple terms and be free of industry jargon. All communication should provide up-to-date information, local utilities impacted by the event, and simple actions to take.

SPP's website is a valuable source of information, but winter weather event was a unique test of its capabilities. It experienced rapid increases in website traffic, hindering the distribution of information. From this, SPP learned how large traffic spikes can be during emergency events and what should be done to mitigate against the risk of negative impacts to the site due to increased traffic. SPP should increase server capacity ahead of weather events and more clearly label banners on the site. Throttling and file reduction can help to reduce disruption further.

KEY FINDINGS RELATED TO COMMUNICATIONS

Overall, SPP's stakeholders were satisfied with and felt appropriately informed by SPP's emergency communications efforts. In a survey of 155 representatives of SPP's member and market participant organizations, 80% rated the overall effectiveness of SPP's communication during the winter storm either "effective" or "highly effective." In a survey of SPP's RSC and CAWG, 85% of respondents rated SPP "effective" or "highly effective." More than 70% of stakeholder respondents and 55% of RSC and CAWG respondents agreed or strongly agreed that SPP's communications increased their trust in the organization's credibility.

There were exceptions to stakeholders' satisfaction with SPP's emergency communications. Some individuals did not receive information in as timely a manner as they would have liked. In many cases, this occurred because SPP sent communications to particular points of contact at its stakeholder organizations and that information was not further disseminated within those organizations.

Some stakeholders were unsure what to do with the information they received during the event. While SPP and its member operators had already developed and practiced response procedures, some other stakeholders were unsure of their roles during the event. This event marked the first time some audiences in the SPP region had heard of or from SPP.

The electric utility industry is complex, and SPP's role is usually "behind-the-scenes." General audiences (including the public, media and elected officials) lack an understanding of the variables that affect the reliable delivery of electricity on a regional scale. SPP tends to communicate using technical language that may be useful for industry professionals but contains too much jargon for general audiences.

The winter weather event exposed a need for better coordination between SPP, members and distributors to communicate about load shed. As the event worsened and threat of outages became real, audiences who were previously unaware of SPP's role became interested in the RTO's load-shed procedures. They wanted to know what factored into SPP's decisions

regarding Energy Emergency Alerts, calls for conservation and load curtailment. A spike in interest and a need to communicate complex concepts to new audiences proved a challenge.

Post-event analysis confirmed that SPP's transmission-operating and load-serving member utilities all received and responded to load-shed communications in a timely manner. Utilities quickly brought the system into balance and SPP restored load quickly and effectively.

Long after the outages, SPP and its members continued to field questions from distribution companies, regulators, reporters and the public about SPP's authority to curtail load, SPP's and its members' roles in choosing what load to curtail and why curtailing load was necessary.

COMMUNICATIONS RECOMMENDATIONS

Table 20: Summary of recommendations to the board related to communications

#	TIER	CATEGORY	RECOMMENDATION
COMM 1	2	Action	Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: • Processes that ensure stakeholders have a dependable way to receive timely, accurate and relevant information regarding emergencies. • Plans to drill emergency communications procedures with all relevant stakeholders. • Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers, and government entities and stay up-to-date.
COMM 2	2	Assessment	Evaluate and propose needed enhancements to communications tools and channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc.
COMM 3	3	Action	Form a stakeholder group whose scope would include discussion of matters related to emergency communications.
COMM 4	3	Action	To increase public awareness of and satisfaction with SPP, develop materials intended to educate general audiences on foundational electric utility industry concepts and SPP's role in ensuring electric reliability.

CONCLUSION

The February 2021 winter weather event was historic in nearly every respect, from the widespread and severe nature of the storm itself to the response it required from SPP and its stakeholders to preserve the reliability of the regional grid. SPP credits its success in responding to the winter storm to its many partners, including its member utilities, neighboring systems and millions of people who voluntarily made sacrifices to conserve energy in the interest of the greater good. Likewise, SPP owes its stakeholders thanks for their thoughtful and deliberate contributions to this report.

In a statement to SPP's staff on Feb. 18, in the immediate aftermath of the storm, SPP's president and CEO wrote the following regarding the organization's obligation to learn from the experience:

> *"We will do our best and we will come out on the other side wiser and more prepared for the future. Will we learn from the events of this week? Definitely. We will identify improvements? Most certainly. Will our best be even better next time? Absolutely."*

Many of the factors that contributed to the severity of the February storm's impacts were externalities that SPP could not control: low temperatures, the duration of the storm and fuel prices set by gas providers, for instance. Similarly, SPP and its stakeholders will almost inevitably face other crises that arise from circumstances they cannot prevent, whether they result from natural disasters, mechanical failures or acts of terrorism. This comprehensive review, though, demonstrates the SPP organization's commitment to doing everything in its power to safeguard the reliability and affordability of electricity delivery in its region.

As this report's name suggests, SPP's analysis of its response to the February storm was comprehensive. The results are indicative of dozens of meetings in which hundreds of stakeholders spent thousands of hours considering how to achieve SPP's mission — responsibly and economically keeping the lights on today and in the future — even when facing the toughest challenges imaginable. This report does not mark the end of SPP's learning process, though. From here, with direction from SPP's independent board, SPP will set about the ongoing process of continuing to engage stakeholders in making the recommended improvements. Where assessments need to be made, plans carried out or policies written or amended, SPP staff will partner closely with stakeholders, because SPP's success, in the past, present and future, depends largely on the strength of its stakeholder engagement.

APPENDICES

APPENDIX A: SPP'S ROLES IN ASSURING ELECTRIC RELIABILITY

SPP serves in a number of capacities related to the coordination of the regional power grid. Those most relevant to the February 2021 winter weather event are its roles as a regional transmission organization (RTO), reliability coordinator, balancing authority and market administrator.

SPP AS AN RTO

As an RTO, SPP is granted specific responsibilities by the Federal Energy Regulatory Commission (FERC). Rates, terms and conditions by which SPP oversees the regional power grid and coordinates with its member utilities are defined in a FERC-approved tariff. 106 member utilities in 14 states are members of the SPP RTO, meaning they have placed their power plants and extra high-voltage transmission facilities under SPP's functional control. RTO membership is voluntary, though the member roster has steadily grown since SPP became an RTO in 2004 because of the value the organization provides: enhanced reliability and cost savings as compared to the status quo of utilities operating on their own.

SPP AS A RELIABILITY COORDINATOR

As a reliability coordinator (RC), SPP functions like an air traffic controller for electricity. Air traffic controllers don't own skies, planes or airports they coordinate. Similarly, SPP doesn't own power plants, transmission lines or electricity, but it directs these and other components of the bulk power system to ensure electricity is delivered safely and affordably from where it's generated to where it's used in real time. RC activities are governed by the North American Electric Reliability Corporation (NERC), who enforces standards related to the reliable operation of the country's bulk electric system. (For more information on the standards most relevant to the winter event, see the Applicable Standards and Regulations section.)

SPP staffs a 24/7 control room and backup facility from which it maintains constant communication with member utilities. RC staff constantly plan for contingencies and operate from an N-minus-one posture, meaning they work to keep the grid ready to respond to the next worst contingency such as the loss of our largest generating unit. SPP keeps operating reserves online equivalent to one-and-a-half times its region's largest generating unit. This means it keeps enough generation online to meet real-time demand and enough "spinning" and ready to flow onto the grid immediately if committed generation becomes unavailable.

SPP AS A BALANCING AUTHORITY

The nation's power grid comprises three interconnections: Eastern, Western and ERCOT (Texas). Each is a single massive, highly interconnected network of generators, transmission lines and substations that feed power to local distribution networks that serve homes and businesses. Disturbances anywhere on one of these networks are felt across the entire interconnection. The SPP RTO is part of the Eastern Interconnection.

As a balancing authority (BA), SPP keeps real-time production and consumption of electricity in balance. It does this for its entire 14-state balancing authority area. Other entities serve as the BAs in other regions, big and small, across the country. Production and consumption of electricity must be kept nearly perfectly in balance to prevent equipment failures and the potential for large-scale, cascading outages. In the absence of utility-scale energy storage devices like batteries, electricity is produced, transported, delivered and consumed nearly simultaneously. Damage to the grid can occur if either more or less energy is produced than is needed at that time. SPP forecasts demand (also called load) in five-minute increments, and sends signals to 800+ generators in its BA area to ensure they're collectively producing just enough power to meet demand without overloading lines or burning out equipment.

SPP AS A MARKET ADMINISTRATOR

SPP facilitates a wholesale electricity market that automates selection of the cheapest available energy to serve load minute-by-minute. SPP's market is fuel-agnostic, meaning it doesn't favor any particular fuel type over another but treats coal the same as wind, natural gas the same as nuclear power, etc. The market only takes into account the price at which generators offer energy into the market, and it picks the least-cost power available to meet demand, taking into account operating characteristics such as lead times (the amount of time it takes a generator to spin up from inactivity), minimum run-times, etc.

SPP's is a day-ahead market, meaning it commits generation a day in advance. As the region nears real-time, intraday market processes make additional commitments to ensure the right amount of generation is online as weather patterns, electricity use and other factors vary from forecasts.

Like its tariff, SPP's market design is approved by FERC, and its administration is overseen by an independent market monitor that watches to ensure the market operates fairly and without undue influence by any single participant or group of like-minded participants. SPP is a not-for-profit organization, registered as a 501(c)(6) in the state of Arkansas. As a market administrator, it facilitates the sale and purchase of power through its market, and SPP administers the process by which those transactions are invoiced and settled, but it does not profit off these activities. SPP is completely funded by an administrative fee charged to our members and market participants based on the use of our services.

In summary, SPP is authorized and regulated by FERC to carry out certain responsibilities related to the reliable operation of the regional power grid. It is required to comply with enforceable NERC standards, and its staff works around the clock every day to ensure energy production and consumption are held in balance while planning against contingencies that could threaten reliability. SPP's market helps do this by committing the least-cost generation that's available to serve load.

APPENDIX B: PREPARATION AND TRAINING

SPP holds its operators to exceptionally high training standards, ensuring every operator exceeds NERC's minimum training requirements and is equipped to respond to a wide array of operational issues. This includes specific training that addresses cold-weather events. SPP's operators work on six-week shifts, which include one week every rotational schedule dedicated to training.

NERC requires system operators to undergo 200 hours of training every three years to maintain their RC certification. SPP holds its operators to standards above those requirements, ensuring every one receives 85-100 hours of training every year. SPP also requires every operator to be certified both as an RC and on the specific functions they perform.

SPP requires its operators to receive training consistent with NERC Standard PER-005. Additionally, it requires operators to complete emergency operations training annually consistent with standards EOP-006 (System Restoration), EOP -011 (Emergency Operations), IRO-008 (Reliability Coordinator Operational Analyses and Real-time Assessments), IRO-009 (Reliability Coordinator Actions to Operate within IROLs) and PRC-001 (System Protection Coordination).

Operators typically earn 65-80 continuing education hours (CEH) annually from events developed and delivered by SPP's customer training staff. These training events — also attended by SPP members' operators — include Regional Emergency Operations (REOPS) classes, Power System Restoration drills, System Operations Conferences, and classes that focus on specific topics like conservative operations, event reporting, energy emergency alerts and unit commitment fundamentals. Many of these sessions include training specifically intended to prepare operators to respond to cold-weather events, and plans are already underway to update training content that incorporates circumstances and lessons learned from the February 2021 winter weather event.

Operators also receive training delivered by SPP's operations analysis and performance support (OAPS) team. This training, which does not count toward NERC CEH requirements, is based on real-world situations that might occur in SPP's control room and addresses topics like communications, the potential loss of a control center, remedial action schemes, capacity emergencies, severe loading transmission emergencies, load shed and energy emergency alerts. OAPS training typically provides every operator 30-35 hours of role-specific training each year.

SPP also performs R-Comm training to review how the SPP BA uses R-Comm to issue load-shed instructions and how entities are expected to respond to the communication.

LOAD-SHED TRAINING

SPP's operations staff performs load-shed tests every 11th Wednesday. SPP does not test individual TOP plans, but some TOPs inform SPP when they test their demand-side load-shed plans.

SPP operations engineering staff review documents that members submit related to NERC EOP standards, including load-shed plans. SPP reviews TOP or BA-submitted plans within 30 days of receipt to:

- Confirm that notification to the RC is included when experiencing an operating emergency.
- Mitigate operating emergencies regarding any reliability risks identified between operating plans.
- Confirm compatibility and interdependency with other BA and TOP operating plans.
- Confirm coordination to avoid risk to wide-area reliability.
- Review and confirm any communication information listed for SPP.
- Review each document for consistency with SPP criteria and procedures when interactions with SPP are required.
- Review each topic discussed for criteria and compare against SPP's operating criteria.

APPENDIX C: APPLICABLE STANDARDS

Below are the NERC standards most relevant to SPP's and its members' obligations during the winter weather event.

- Emergency Preparedness and Operations (EOP): EOP-011-1 - Emergency Operations.
- Transmission Operations (TOP):
  - TOP-001-4 – Transmission Operations.[26]
  - TOP-002-4 – Operations Planning.
- Resource and Demand Balancing (BAL): BAL-001-2 - Real Power Balancing Control Performance.
- Interconnection Reliability Operations and Coordination (IRO): IRO-001-4 - Reliability Coordination – Responsibilities.

[26] TOP-001-4 was in effect during the event but was retired and replaced with TOP-001-5 on April 1, 2021.

APPENDIX D: PRIOR RELIABILITY EVENTS

Before the February 2021 winter storm event, the SPP and neighboring regions experienced extreme winter weather conditions in 2011 and 2018 that resulted in two joint Federal Energy Regulatory Commission and North American Electric Reliability Corporation (FERC/NERC) reports. [27,28] The 2011 event report made 26 recommendations for the electric industry and six for the gas industry, including improved coordination between the electric and gas industries. Recommendations for the electric industry focused on five areas: planning and reserves, coordination with generator owners and operators, winterization, communication and load shedding. The 2018 event report contained 13 recommendations related to generator cold weather reliability, situational awareness, reliability coordinator communications, seasonal studies, system operating limits, reserves and load forecasting.

As part of SPP's comprehensive review following the February 2021 event, an assessment of the previous event recommendations was conducted. SPP's current operational and planning processes and tools incorporate a majority of the applicable recommendations from both events.

FEB. 1-5, 2011, SOUTHWEST COLD WEATHER EVENT

This event involved extremely low temperatures, wind, snow and ice. Electric entities located within three NERC regions, the Texas Reliability Entity, Inc. (TRE), the Western Electricity Coordinating Council (WECC), and SPP were affected by the extreme weather, as were gas entities in Texas, New Mexico and Arizona. While three balancing authorities (BA) in the SPP footprint issued varying levels of energy emergency alerts (EEAs), no load shedding occurred, and SPP was not directly mentioned in any of the recommendations.

SPP was not a BA at the time of the 2011 event, but due to SPP's current NERC registrations as a BA, planning coordinator (PC), transmission planner (TP), reliability coordinator (RC), reserve sharing group (RSG) and transmission service provider (TSP), a number of the recommendations were considered for potential improvements to SPP's operational and planning processes. Some recommendations are specific to the Electric Reliability Council of Texas (ERCOT) and WECC, but due to SPP's current NERC registrations, these were included as part of the comprehensive assessment.

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[27] https://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/SW_Cold_Weather_Event_Final.pdf

[28] https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

PLANNING AND RESERVES

The 2011 event report recommended that all entities responsible for the reliability of the bulk power system in the Southwest prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season. Recommendations included augmenting studies with scenarios like the 2011 winter conditions and changing operating practices to allow increased lead time for generator preparations, canceling previously scheduled outages and increasing reserves.

SPP conducts seasonal planning assessments as part of the integrated resource planning process. These assessments consider scenarios across a broad range of weather conditions, including seasonal generator capabilities. Extreme scenarios are included in NERC Transmission Planning Standards (TPL), Under-Frequency Load Shedding (UFLS) and annual transfer capability studies. SPP's planning criteria specifies generator testing requirements and generator owners and operators convey current information on seasonal capabilities including fuel switching, fuel supply and black-start capability.

SPP's staff works constantly to prepare for a range of expected and unexpected operational conditions by evaluating various scenarios based on short and midterm weather forecasts. These uncertainly levels are incorporated into the load and wind forecast outlook in the multiday resource availability assessments. Recommendations are provided to generator operators (GOPs) if early commitments are needed and SPP relies on the generators to make appropriate preparations, which can include pre-warming. SPP's personnel, processes, and systems have the ability to manage the clearing and delivery of operating reserves through reserve zones.

COORDINATION WITH GENERATOR OWNERS AND OPERATORS

Several recommendations involve coordination between transmission operators (TOPs), BAs and GOPs to develop mechanisms to verify generator capabilities such as fuel-switching, black-start capability and temperature performance. SPP's planning criteria includes testing requirements for generating units that incorporates seasonal parameters.

SPP also holds an annual winter preparedness workshop and transmission operators and generator operators typically give presentations on their upcoming winter preparedness. Attendees include members of SPP's ORWG. The 2020-2021 winter preparedness workshop was Sept. 29, 2020.

COMMUNICATIONS

This event highlighted the need for better communication about emergency situations between BAs, RCs and other market participants. SPP utilizes a number of communications including cold weather alerts, resource alerts and conservative operation notices. SPP's Reliability Communication Tool (R-COMM) is used to facilitate operator to operator communication between SPP and TOPs, BAs and RCs. The tool is also used by TOPs, BAs and RCs to communicate with SPP and each other.

ELECTRIC/GAS COORDINATION

This event highlighted many areas for improvement between the electric and gas industries. Recommendations included working with state regulators to adopt standards to winterize critical gas systems, allow critical gas systems to be exempt from load-shedding plans, and prioritize demands on gas supply. Electric/gas coordination requires engagement by numerous stakeholders at the federal and state level and across multiple agencies. After the 2011 event, SPP has been involved in efforts at the North American Energy Standards Board (NAESB) and NERC to improve coordination between the electric and gas industries.

- *North American Energy Standards Board*

  In both 2014 and 2016, NAESB undertook gas-electric harmonization (GEH) in response to a FERC directive. During that time, SPP worked with gas operators within our footprint to improve coordination and to make changes to the market bidding timeline.

- *North American Electric Reliability Corporation*

  SPP has been involved in the NERC Electric Gas Working Group who has been updating a guideline that includes recommendations to improve electric gas coordination. The guideline focuses on the areas of preparation, coordination, communication and intelligence that may be applied to improve gas and electric coordinated operations and minimize interdependent risks. The guidance is not a "one size fits all" set of measures but rather a list of principles and strategies that can be applied according to the circumstances encountered in a particular system, balancing authority, generator fleet or even an individual generator operator.

SOUTH CENTRAL COLD WEATHER EVENT JAN. 17, 2018

Below-average temperatures resulted in 183 individual generating units within the reliability coordinator footprints of SPP, Midcontinent Independent System Operator (MISO), Tennessee Valley Authority (TVA) and Southeastern Reliability Coordinator (SeRC) experiencing either an outage, a derate or a failure to start between Jan. 15-19, 2018. All of the recommendations from this event were reviewed, although a number of the recommendations were specific to MISO.

NERC RELIABILITY STANDARDS

The 2018 report recommended a three-pronged approach to ensure generator owners/generator operators, RCs and balancing authorities prepare for cold weather conditions, including the development of new or enhanced reliability standards. Recognizing the importance of the 2018 recommendations to improve operations, communication and coordination during extreme winter weather conditions, SPP sponsored the Standard Authorization Request (SAR) that led to NERC's winter weather reliability standard project. (Project 2019-06 Cold Weather.)

SPP led the industry's effort to finalize the SAR that was approved by NERC's Standard Committee. SPP chaired the Standard Drafting Team (SDT), and through NERC's collaborative process with interested stakeholders, the project recently received strong industry support. The project focuses on the first prong of the recommended approach and includes three revised reliability standards related to emergency preparedness (EOP-011-2), RC data specification and collection (IRO-010-4) and operational reliability data (TOP-003-5).

The NERC board of trustees adopted the project during a special session June 11, 2021, and authorized staff to file it with FERC.

SITUATIONAL AWARENESS

In the 2018 event report, FERC/NERC acknowledged that the relevant RCs (MISO, SPP, TVA and SeRC) had situational awareness throughout the event and communicated as necessary to preserve system reliability. However, four of the recommendations focused on situational awareness since the event involved large power transfers across four RCs. Performing additional studies and scenarios based on event conditions and conveying the results of the analysis to adjacent RC areas was recommended. Voltage stability studies were recommended, and SPP's voltage stability analysis tool became operational in mid-2018. SPP has implemented a process to identify additional study types for different constraint types that includes communication steps with adjacent RCs and impacted TOPs.

SPP and other RCs conduct capacity and energy drills on a periodic basis and system transfer scenarios are included in the training. The Jan. 17, 2018, State Estimator case was used to formulate customer training scenarios for six sessions in 2020. SPP will also conduct a pilot for the capacity and energy exercise for FERC to attend on Sept. 8, 2021, and the joint exercises with MISO on Sept. 23, 2021, and Oct. 7, 2021.

RC TO RC COMMUNICATIONS

To improve RC-to-RC communications, the 2018 report also made specific language change recommendations to the Regional Transfer Operating Procedures (RTOP). The recommendations were meant to provide more specificity to certain sections and improve communications related to Regional Directional Transfers and analysis of flow impacts. SPP is part of the Regional Transfer Operating Committee (RTOC) who owns the RTOP. Following the January 2018 event, the RTOC adopted modifications meeting the intent of the 2018 report recommendation, although some work remains.

SEASONAL STUDIES

The 2018 report recommended that RCs and PAs study more extreme conditions that include removing generators in their entirety, extreme condition load forecasting and benchmarking of actual events. The report also recommended that MISO and SPP perform seasonal transfer studies. SPP and MISO had calls in 2019 and 2020 to discuss worse case scenarios to be

included in seasonal studies. SPP and MISO coordinated and developed a few common scenarios for winter 2021 for multiple contingencies and extreme conditions (similar to Jan. 17, 2018) to identify constraints on seams that may be difficult to mitigate with normal congestion management processes. Operating guides were developed and reviewed with neighboring RCs and impacted TOPs. These scenarios will be provided to the training department for them to develop RC and TOP training including load shedding.

SYSTEM OPERATING LIMITS

This recommendation applied to the establishment of facility ratings by TOs and TOPs and the provision of those ratings to the RC for use in applications such as the Energy Management System (EMS) and Real-Time Contingency Analysis tools. SPP has a Rating Submission Tool used by TOPs to submit facility ratings. SPP staff reviewed this recommendation with RTO stakeholders in the Transmission Working Group (TWG) and ORWG to stress the importance of this recommendation.

RESERVES

The reserve recommendations focused on the deliverability of reserves, and MISO's communication with other RCs when it needs to rely on any amount of nonfirm, as available portion of the Regional Directional Transfer (RDT) to meet its reserves. All BAs have deliverability assurance processes in place. SPP has reserve zones modeled in the SPP Market System and can use those as needed. SPP staff reviews market solutions daily and this includes looking for stranded reserves. MISO and SPP's RCs communicate often during abnormal operating conditions and when MISO is depending on RDT to meet reserves.

LOAD FORECASTING

The load-forecasting recommendations were specific to MISO; however, their forecasting team reached out to SPP and staff reviewed load forecasting best practices. MISO is working on a forecasting survey with other ISOs/RTOs and will share the results with SPP upon completion.

SUMMARY

SPP is committed to identifying and improving our own processes and quickly initiated a comprehensive assessment of the February 2021 event, including a review of FERC and NERC recommendations from past winter events. We have determined SPP's current processes and tools encompass the majority of recommendations from the 2011 and 2018 events.

FERC and NERC began a review of the 2021 event on Feb. 16, 2021, and the results of the inquiry are not expected until this fall. SPP will review the recommendations from the inquiry and if not previously self-identified, will evaluate for inclusion in our implementation plan(s).

It is unknown at this time whether NERC or NAESB will undertake projects to improve electric-gas coordination or develop new or revised standards as a result of the 2021 event, but SPP will engage in projects as appropriate to improve the reliability of the bulk power system during extreme events.

APPENDIX E: COMMUNICATIONS SURVEY OF RSC AND CAWG MEMBERS

EXECUTIVE SUMMARY

The SPP communications department launched the RSC - Winter Storm Event Survey March 30, 2021, and closed the survey April 9, 2021. Staff distributed survey invitations to the 10 members of the Regional State Committee (RSC), the 11 members of the Cost Allocation Working Group (CAWG), and extended an invitation to complete the survey to the Texas Office of Public Utility Counsel (OPUC).

Ten RSC commissioners, nine members of the CAWG, and one member of the Texas OPUC completed the survey. The distribution of respondents by state is shown in Table 1.

On a scale of zero to four, with zero being "Highly Ineffective" and four being "Highly Effective," survey respondents gave an average rating of 2.95 when rating SPP's overall effectiveness during the winter storm event.

Table 1: Respondents by State

State	Respondents
Arkansas	2
Iowa	2
Kansas	2
Louisiana	2
Missouri	1
Nebraska	2
New Mexico	2
North Dakota	2
Oklahoma	2
South Dakota	2
Texas	1

Table 2: Overall Effectiveness

Q1. How would you rate the overall effectiveness of SPP's communication during the winter storm event?		
Respondent Type	**Average Rating**	**Equivalent Score**
Commissioners (10)	3.00	Effective
CAWG representatives (9)	2.88	Effective
Other (Texas OPUC, 1)	3.00	Effective
All Respondents	**2.95**	**Effective**

For individual categories of communication performance, the lowest ratings were given to the performance of SPP's members, and to assessments of how SPP and its members shared responsibility of communication with government and regulatory officials.

Some of the themes staff identified in open-ended responses were: a desire to improve advance notification, a need for more consistent communication from SPP and members, a need for clear sources of information and points of contact, a desire to improve the frequency of communication during an event, a need for more collaboration to reach overlapping audiences, and an opportunity to educate regulators, members and the public about these types of emergency events and how to respond.

SURVEY RESULTS BY QUESTION

The survey asked respondents to their agreement with the following statements below.

Q4: SPP's communication during the winter storm event was timely.

	Response percent	Response total
Strongly Agree	15%	3
Agree	65%	13
I don't know	5%	1
Disagree	15%	3
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q5: SPP communicated with appropriate frequency during the winter storm event.

	Response percent	Response total
Strongly Agree	10%	2
Agree	60%	12
I don't know	15%	3
Disagree	15%	3
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q6: Communication from SPP during the winter storm event was clear and understandable.

	Response percent	Response total
Strongly Agree	15%	3
Agree	70%	14
I don't know	5%	1
Disagree	10%	2
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q7: SPP effectively used a variety of communication methods (email, press releases, webinars, phone calls, website updates and social media) during the event.

	Response percent	Response total
Strongly Agree	20%	4
Agree	40%	8
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q8: SPP's leadership demonstrated necessary knowledge and expertise during the event, and were consistent in the delivery of their message.

	Response percent	Response total
Strongly Agree	25%	5
Agree	65%	13
I don't know	5%	1
Disagree	5%	1
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q9: SPP's communications clearly explained the actions stakeholders should take during the winter storm event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	50%	10
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	5%	1

Statistics based on **20** respondents;

Q10: SPP's communications during the event increased my trust in the credibility of SPP.

	Response percent	Response total
Strongly Agree	10%	2
Agree	45%	9
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	5%	1

Statistics based on **20** respondents;

Q11: SPP staff were available and willing to answer my questions during the event.

	Response percent	Response total
Strongly Agree	25%	5
Agree	45%	9
I don't know	30%	6
Disagree	0%	0
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q12: SPP's member organizations effectively communicated actions they were taking during the winter storm event.

	Response percent	Response total
Strongly Agree	15%	3
Agree	25%	5
I don't know	25%	5
Disagree	20%	4
Strongly Disagree	15%	3

Statistics based on **20** respondents;

Q13: SPP and its member organizations effectively shared responsibility for communicating with regulators during the event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	25%	5
I don't know	40%	8
Disagree	20%	4
Strongly Disagree	10%	2

Statistics based on **20** respondents;

Q14: SPP and its member organizations effectively shared responsibility for communicating with other elected officials during the event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	15%	3
I don't know	75%	15
Disagree	0%	0
Strongly Disagree	5%	1

Statistics based on **20** respondents;

APPENDIX F: COMMUNICATIONS SURVEY OF STAKEHOLDERS

SURVEY RESULTS BY QUESTION

Q1. Which of the following applies to you? (check all that apply)		
Respondent Type	**#**	**%**
Communications staff at an SPP member organization	31	20%
Government affairs staff at an SPP member organization	22	14%
Regulatory staff at an SPP member organization	17	11%
Operational staff at an SPP member organization	45	29%
Market staff at an organization participating in SPP's Integrated Marketplace	15	10%
Roster member of an SPP working group or committee	58	37%
Members Committee member of SPP	25	16%
SPP board member	7	5%
SPP staff	0	0%

Communications staff at an organization that is not a member of SPP	2	1%
Other role at an organization that is not a member of SPP	4	3%
Other role at an SPP member organization	16	10%
Other	8	5%
All Respondents (155 respondents)	**250**	**100%**

Q1. In what state(s) does your organization operate?		
State	**#**	**%**
Oklahoma / OK	53	14%
Kansas / KS	46	12%
Nebraska / NE	40	10%
Texas / TX	33	9%
Arkansas / AR (and one response of "AK" probably intended to be "AR")	27	7%
Missouri / MO	27	7%
South Dakota / SD	25	7%
New Mexico / NM	22	6%
Iowa / IA	21	5%
Louisiana / LA	17	4%
Minnesota / MN	17	4%
North Dakota / ND	17	4%
Montana / MT	12	3%
Wyoming / WY	13	3%
Colorado / CO	9	2%
Arizona / AZ	1	0%
California / CA	1	0%
Nevada / NV	1	0%
Utah / UT	1	0%
All Respondents (152 respondents)	**383**	**100%**

Q3: How would you rate the overall effectiveness of SPP's communication during the winter storm event? (154 responses)

	Response percent	Response total
Highly Effective	13.64%	21
Effective	66.23%	102
Neutral	16.23%	25
Ineffective	2.6%	4
Highly Ineffective	1.3%	2

The survey asked respondents to their agreement with the following statements.

Q4: SPP's communication during the winter storm event was timely. (155)

	Response percent	Response total
Strongly Agree	23.87%	37
Agree	58.71%	91
I don't know	7.1%	11
Disagree	9.03%	14
Strongly Disagree	1.29%	2

Q5: SPP communicated with appropriate frequency during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	26.45%	41
Agree	54.84%	85
I don't know	9.03%	14
Disagree	8.39%	13
Strongly Disagree	1.29%	2

Q6: Communication from SPP during the winter storm event was clear and understandable. (155)

	Response percent	Response total
Strongly Agree	24.52%	38
Agree	56.77%	88
I don't know	10.32%	16
Disagree	7.74%	12
Strongly Disagree	0.65%	1

Q7: SPP effectively used a variety of communication methods (email, press releases, webinars, phone calls, website updates and social media) during the event. (155)

	Response percent	Response total
Strongly Agree	21.94%	34
Agree	54.84%	85
I don't know	17.42%	27
Disagree	5.16%	8
Strongly Disagree	0.65%	1

Q8: SPP's communications clearly explained the actions stakeholders should take during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	18.07%	28
Agree	50.32%	78
I don't know	18.71%	29
Disagree	10.97%	17
Strongly Disagree	1.94%	3

Q9: SPP communications during the event increased my trust in the credibility of SPP. (155)

	Response percent	Response total
Strongly Agree	20%	31
Agree	50.32%	78
I don't know	24.52%	38
Disagree	3.87%	6
Strongly Disagree	1.29%	2

Q10: SPP's leadership demonstrated necessary knowledge and expertise during the event, and were consistent in the delivery of their message. (155)

	Response percent	Response total
Strongly Agree	29.03%	45
Agree	58.71%	91
I don't know	8.39%	13
Disagree	3.23%	5
Strongly Disagree	0.65%	1

Q11: SPP staff were available and willing to answer my questions during the event. (155)

	Response percent	Response total
Strongly Agree	30.32%	47
Agree	41.94%	65
I don't know	27.1%	42
Disagree	0%	0
Strongly Disagree	0.65%	1

Q12: SPP's member organizations effectively communicated actions they were taking during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	8.39%	13
Agree	46.45%	72
I don't know	32.9%	51
Disagree	10.97%	17
Strongly Disagree	1.29%	2

Q13: SPP and its member organizations effectively shared responsibility for communicating with regulators during the event. (22 Respondents – this question was only available to respondents who indicated they were government affairs or regulatory staff)

	Response percent	Response total
Strongly Agree	9.09%	2
Agree	45.46%	10
I don't know	31.82%	7
Disagree	13.64%	3
Strongly Disagree	0%	0

Q14: SPP and its member organizations effectively shared responsibility for communicating with other elected officials during the event. (22 Respondents – this question was only available to respondents who indicated they were government affairs or regulatory staff)

	Response percent	Response total
Strongly Agree	13.64%	3
Agree	31.82%	7
I don't know	27.27%	6
Disagree	27.27%	6
Strongly Disagree	0%	0

SOUTHWEST POWER POOL, INC.
Comprehensive Review Steering Committee

RECOMMENDATION TO THE SPP BOARD OF DIRECTORS
July 26, 2021

COMPREHENSIVE REVIEW STEERING COMMITTEE ROSTER

- **Lanny Nickell**: Chair (MOPC Staff Secretary and SPP Chief Operating Officer)
- **Larry Altenbaumer** (SPP Board of Directors Chair)
- **Barbara Sugg** (SPP President and Chief Executive Officer)
- **Betsy Beck:** Finance review co-lead (Members Committee representative and Enel Green Power North America Director of Organized Markets)
- **Denise Buffington**: Operations review lead (MOPC Chair and Evergy Director of Regulatory Affairs)
- **Keith Collin:**, Market monitoring review lead (SPP Market Monitoring Unit Executive Director)
- **Tom Dunn**: Finance review lead (Finance Committee Staff Secretary and SPP Chief Financial Officer)
- **Kristie Fiegen**: Regional State Committee review lead (Regional State Committee Chair and South Dakota Public Utilities Commissioner)
- **Joe Lang**: Operations review co-lead (Members Committee representative and Omaha Public Power District Director of Energy Regulatory Affairs)
- **Mike Ross**: Communications review lead (SPP Senior Vice President of Government Affairs and Public Relations)

BACKGROUND, GOALS AND DRIVERS

SPP experienced the most operationally challenging week in its 80-year history during Feb. 14-20, 2021. Due to record-low temperatures and high electricity use, the overall reliability of the bulk electric system was severely tested. SPP kept the lights on across its region with two short exceptions. SPP directed its transmission operators to curtail electricity use by about 1.5% for 50 minutes on Feb. 15 and by about 6.5% for approximately three hours on Feb. 16.

In a special meeting of the SPP Board of Directors and Members Committee on March 2, 2021, the board directed a comprehensive review of SPP's and its stakeholders' response to the February storm. Five teams were tasked with analyzing operational, financial, communications and other aspects of the event and identifying how SPP can be better prepared for future extreme threats to reliability.

ANALYSIS

The comprehensive review yielded seven key observations:

1. Generation unavailability, driven mostly by lack of fuel, was the largest contributing factor to the severity of the event's impacts. This root cause drives the need to develop policies that improve fuel assurance and resource adequacy. It highlights the need to further assess SPP's ability to reliably operate the system with more intermittent and fewer base-load resources. Better coordination and communication between the gas and electric industries could have significantly improved preparation activities.

2. Extremely high natural gas prices were the primary driver of record-high energy offers that exceeded the FERC-required offer cap of $1,000/megawatt-hour (MWh) for the first time in SPP's market history.

3. The rapid spike in SPP's market prices resulted in an immediate concern about liquidity of market participants and created an exponential increase in short-term credit exposure.

4. Relationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event. This emphasizes the value these relationships and robust transmission interconnections provide during emergency events and the opportunity to further strengthen them.

5. The SPP transmission system was highly congested at times during the event with limitations that prevented full use of generation available in certain locations. This issue exacerbated SPP's need to achieve balance between regional supply and demand through use of its load-shed procedures and raised questions about the appropriateness of regionally allocating load-shed responsibilities.

6. Early preparation, timely decisions and effective communication helped minimize the winter storm's impact on reliability. Early communication of a public conservation appeal contributed to reduced demand Feb. 15, reducing the amount of controlled service interruptions required. Effective communication of and prompt response to load-shed instructions likewise mitigated the risk of uncontrolled blackouts.

7. SPP's stakeholders indicated general satisfaction with SPP's emergency communications, information sharing and credibility related to the winter storm response, although some areas of improvement were identified, particularly in those related to end-use customer awareness.

REPORT'S RECOMMENDATIONS

The Comprehensive Review Steering Committee's report recommends 22 actions, policy changes and assessments categorized in three tiers according to urgency, importance, impact and other factors. Full implementation of many of these recommendations will be subject to further approvals as prescribed by SPP bylaws.

Recommendations are categorized according to a three-tier ranking system:

- **Tier 1:** Recommended actions, policies or assessments deemed necessary and urgent to avoid severe reliability, financial, operational, compliance or reputational risks. These recommendations are expected to address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts. Upon board approval, work associated with implementation of these recommendations shall be prioritized by the organization at the highest level and begin immediately.

- **Tier 2:** Recommended actions, policies or assessments deemed necessary to minimize the risk of severe reliability, financial, operational, compliance or reputational consequences associated with extreme system events. These recommendations may not address system-related root causes of the 2021 winter event or mitigate occurrence of future extreme system event impacts, but are important, are expected to significantly improve SPP's response to extreme system events in the future, and shall be treated as high-priority initiatives.

- **Tier 3:** Recommended actions, policies or assessments that would improve SPP's response, communications and public perception during extreme system events, but are not urgent.

Recommendations are categorized into three types:

Action: Development and/or implementation of a new process, requirement, protocol or other activity.

Policy: Development of principles to be used to guide subsequent development of requirements, protocols, and/or processes using the stakeholder process in accordance with bylaws, tariff provisions and applicable regulations.

Assessment: Performance of analysis that informs development of solutions through the stakeholder process.

The following charts summarize the recommendations by tier and category:

RECOMMENDATIONS BY TIER

	Tier 1	Tier 2	Tier 3
Fuel Assurance (FA)	2	1	-
Resource Planning & Availability (RPA)	2	-	-
Emergency Response Process & Planning (ERP)	-	3	-
Operator Tools, Communication and Processes (OTCP)	-	1	-
Seams Agreements (SEAMS)	-	1	-
Market Design (MKT)	-	3	-
Transmission Planning (TXP)	-	1	1
Credit (CR)	-	1	2
Communications (COMM)	-	2	2
22 TOTAL	4	13	5

RECOMMENDATIONS BY CATEGORY

	Action	Policy	Assessment
Fuel Assurance (FA)	-	2	1
Resource Planning & Availability (RPA)	-	1	1
Emergency Response Process & Planning (ERP)	1	1	1
Operator Tools, Communication and Processes (OTCP)	1	-	-
Seams Agreements (SEAMS)	1	-	-
Market Design (MKT)	1	2	-
Transmission Planning (TXP)	-	2	-
Credit (CR)	1	-	2
Communications (COMM)	2	-	2
22 TOTAL	7	8	7

There will be many opportunities for stakeholder feedback on all recommendations, including developing policies and assessing performance. Tier 2 & 3 recommendations will follow stakeholder processes including the Comprehensive Roadmap, Revision Request process, working group approvals, and MOPC and board approvals.

The “Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm” report represents the findings and recommended directional objectives generated during the comprehensive review, as consolidated, synthesized and summarized by SPP staff. The full report can be found in this meeting's background material on spp.org.

RECOMMENDATION

The Comprehensive Review Steering Committee recommends the board of directors:

1. Accept its report, “A Comprehensive Review of Southwest Power Pool’s response to the February 2021 Winter Storm”

2. Direct work to begin on recommendations that address root causes (Tier 1)

3. Direct organizational prioritization of work needed to address remaining recommendations.

SPP'S RESPONSE TO THE FEBRUARY 2021 WINTER WEATHER EVENT

During the week of Feb. 14-20, 2021, locations across the SPP service territory from North Dakota to the Texas panhandle experienced record-low temperatures for days on end. As consumers' electricity and natural gas use increased, power production was limited due to fuel-supply issues, equipment malfunctions, and transmission system constraints. The overall reliability of the bulk electric system was severely tested.

Despite these challenges, SPP was able to continuously maintain a reliable supply of wholesale electric service across its region, with two brief exceptions. Following its emergency operations procedures and to prevent a more severe system failure, SPP directed its transmission operators to temporarily reduce regional electricity use twice: by about 1.5% for 50 minutes on Feb. 15 and by about 6.5% for approximately three hours on Feb. 16. Underscoring the historic significance of this event, these marked the first times in SPP's history region-wide curtailments were necessary.

SPP's independent board directed staff and stakeholders to conduct a comprehensive review of the organization's response to the event. The review yielded seven key observations and 22 recommendations to help SPP learn, mitigate and be better prepared for future extreme reliability threats.

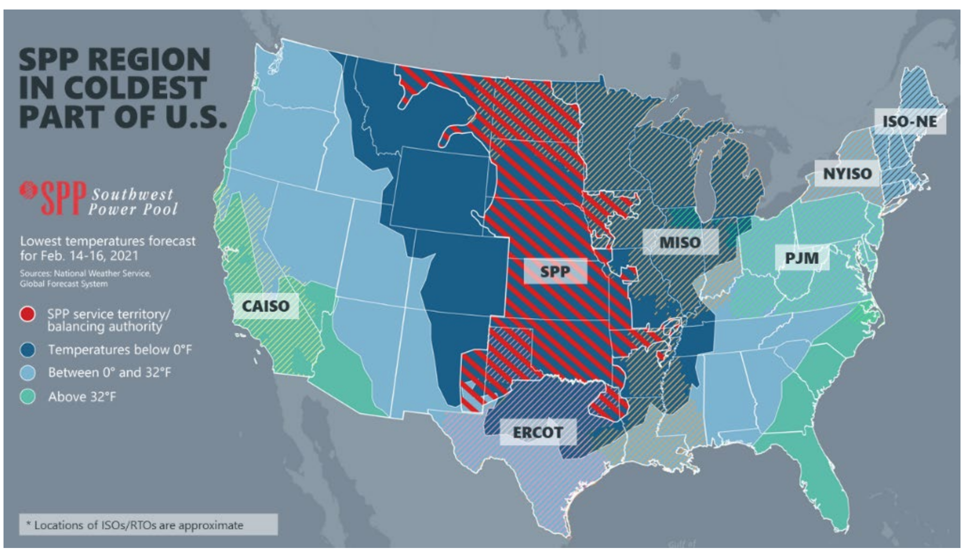
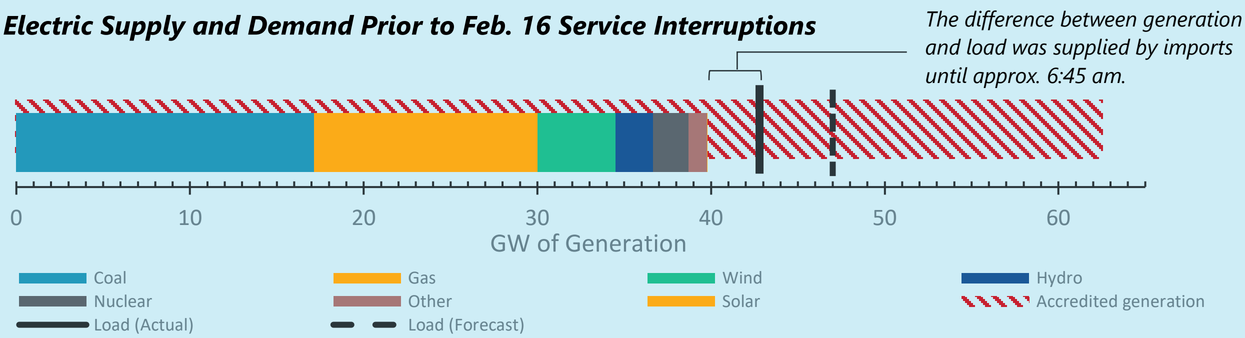


Figure 1: This map illustrates why SPP was so severely impacted by the February 2021 winter storm. The nation's lowest temperatures were felt across the SPP region and lasted for days.

Electric Supply and Demand Prior to Feb. 16 Service Interruptions



This chart illustrates the generation shortfall that led SPP to direct service interruptions on Feb. 16. SPP had approx. 62.6 gigawatts (GW) of accredited generating capacity available during the winter 2021 season. Total available generation on Feb. 16 at approximately 6:45 am was less than 40 GW, but with energy imported from neighbors, SPP was able to meet approx. 43 GW of demand. As available imports lessened, though, SPP had to implement emergency procedures to preserve the overall integrity of the grid. SPP's early forecasts predicted demand to reach as high as 47 GW, though this did not materialize due to consumers' voluntary conservation and SPP's directed interruptions.

KEY OBSERVATIONS

Unavailable Generation and Fuel: Lack of available generation was the primary cause of the event's reliability impacts. Lack of fuel was biggest cause of generation unavailability.

High Gas Prices: Extremely high natural gas prices were the primary drivers of record-high energy offers, exceeding SPP market's offer caps for the first time.

Increased Credit Exposure: The spike in SPP's market prices raised concerns about market participants' liquidity and created an exponential increase in short-term credit exposure.

Helpful Interconnections: Relationships and interconnections with neighboring systems facilitated critically helpful assistance.

Congested Transmission: Full use of generation in certain locations was limited by constraints on the SPP system.

Minimized Reliability Impacts: Early preparation, timely decisions, and effective communication helped minimize reliability impacts while effective execution of load-shed procedures mitigated the risk of uncontrolled blackouts.

Credible Communications and Response: Stakeholders indicated general satisfaction with SPP's emergency communications, information sharing, and credibility, while recognizing the need for improvements.

The comprehensive review evaluated hundreds of process changes, system enhancements, new and amended policies, assessments, and other solutions to address the event's root causes and enable SPP and its stakeholders to improve their response to future extreme system events. SPP's board approved 22 actions, policy changes and assessments to address issues related to fuel assurance, resource planning and availability, emergency response, communications and other critical areas.

A full report of the detailed analysis and recommendations is available on SPP.org.

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, Missouri, this 27th day of July, 2021.

Morris L Woodruff

Morris L. Woodruff
Secretary

MISSOURI PUBLIC SERVICE COMMISSION

July 27, 2021

File/Case No. AO-2021-0264

Missouri Public Service Commission
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Enclosed find a certified copy of an Order or Notice issued in the above-referenced matter(s).

Sincerely,

Morris L Woodruff

Morris L. Woodruff
Secretary

Recipients listed above with a valid e-mail address will receive electronic service. Recipients without a valid e-mail address will receive paper service.