ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE

REPORT 2021

TASK FORCE MEMBERS:

BECKY W. KEOGH, Chair
Secretary, Arkansas Department of Energy & Environment

MIKE PRESTON
Secretary, Arkansas Department of Commerce

LAWRENCE BENGAL
Energy Administrator, Arkansas Department of Energy & Environment
Director, E&E Oil & Gas Commission

KEVIN PFALSER
Director, E&E Liquefied Petroleum Gas Board

I. EXECUTIVE SUMMARY

Extreme cold temperatures and snow in Arkansas and surrounding states during a February 2021 winter weather event disrupted fuel supply, primarily natural gas, for electricity generation and heating. Furthermore, some electric generating units underperformed during the event, and transmission constraints resulted in stranded capacity. At the same time fuel supply and transmission were constrained, electric and gas utilities experienced unprecedented winter demand in the region. In some cases, the demand exceeded summer peaks.

Despite the challenges experienced during the February 2021 winter weather event, coordination among the utilities, state departments and agencies, and multiple regional transmission organizations ("RTOs") ensured that Arkansas fared well during the storm with only limited, short-duration outages during the storm. Arkansas benefited from utility participation in RTOs that were able to draw energy from a wide geographic region with a diverse portfolio of electricity generating assets. The state also benefitted from the existence and availability of interruptible tariffs for large electric customers who voluntarily accept curtailment to reduce the load on the electricity grid in exchange for discounted electricity rates. Where natural gas supply was constrained, human needs were prioritized to ensure that Arkansans stayed warm. Communication of the need to conserve energy was broadcast widely across the state and Arkansans stepped up to meet the need.

Although Arkansas demonstrated that it is well-prepared for events like the February 2021 winter weather event, lessons learned during the storm provide the state with the opportunity to examine what processes worked well and what can be improved upon to ensure reliability during extreme events. To review and analyze lessons learned and develop recommendations, Governor Asa Hutchinson created the Energy Resource Planning Task Force ("Task Force").

After reviewing testimony from regulators, fuel suppliers and transporters, utilities, and energy users, the Task Force has identified potential opportunities for improved communication in advance of and during energy disruptive events and potential opportunities for improving the reliability of energy infrastructure. If outages are necessary to ensure the reliability of the electricity grid or curtailment is necessary due to limited fuel supply or weather-related electric outages, the Task Force recommends prioritizing energy so as to preserve human life, health, and safety and, to the extent possible, to businesses and industry that would otherwise incur damage to equipment or experience severe economic harm. The lessons learned and Task Force recommendations are discussed in more detail within this report.

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II. ACRONYMS AND ABBREVIATIONS

AECC	Arkansas Electric Cooperatives Corporation
AEEC	Arkansas Electric Energy Consumers, Inc.
AEF	Arkansas Environmental Federation
AF&PC	Arkansas Forest and Paper Council
AGC	Arkansas Gas Consumers, Inc.
AIPRO	Arkansas Independent Producers and Royalty Owners
AMPA	Arkansas Municipal Power Association
AGA	American Gas Association
AOGC	Arkansas Oklahoma Gas Corporation
APGA	Arkansas Propane Gas Association
Black Hills	Black Hills Energy Arkansas, Inc. and Black Hills Corporation
CenterPoint	CenterPoint Energy, Inc.
Commerce	Arkansas Department of Commerce
DEQ	Division of Environmental Quality
E&E	Arkansas Department of Energy and Environment
Empire	Empire District Electric Company, Liberty Utilities Co., and their parent company: Algonquin Power & Utilities Corp.
EPN	Energy Policy Network
Entergy	Entergy Corporation and Entergy Arkansas, LLC
EO 21-05	Executive Order 21-05
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
LP-Gas	Liquefied Petroleum Gas (Propane)
MISO	Midcontinent Independent System Operator, Inc.
NERC	North American Electric Reliability Corporation
O&GC	Arkansas Oil and Gas Commission
OG&E	Oklahoma Gas and Electric and OGE Energy Corp.
PPGMR	PPGMR Law, PLLC
PSC	Arkansas Public Service Commission
Quattlebaum	Quattlebaum, Grooms & Tull PLLC
RTO	Regional Transmission Operator
SPP	Southwest Power Pool, Inc.
SWEPCO	Southwestern Electric Power Company
Task Force	Energy Resource Planning Task Force established under Executive Order 21-05

III. INTRODUCTION

On March 3, 2021, Governor Asa Hutchinson issued EO 21-05, creating the Task Force to review lessons learned from the February 2021 winter storms by hearing testimony from a list of identified public and private sector leaders and any other citizen as the Task Force deems necessary; provide recommendations to the Governor for actions needed to ensure adequate supply of critical energy sources during extreme events; and develop priorities for allocation of limited energy resources should supply shortages due to emergency situations necessitate action to preserve life, health, and safety. Becky Keogh, Secretary of E&E; Lawrence Bengal, Director of the Arkansas O&GC; Kevin Pfalser, Director of the Arkansas LP-Gas Board; and Mike Preston, Secretary of Commerce, served as members of the Task Force. Secretary Keogh served as the Task Force Chair. Attached and marked for identification purposes as "Appendix A" is the full text of EO 21-05.

The Task Force conducted three meetings between March 10, 2021, through May 12, 2021, to discuss the entities from which the Task Force should request testimony, the schedule and format of Task Force meetings and hearings, and pre-hearing testimony questions. On April 9, 2021, the Task Force submitted pre-hearing questionnaires to interested parties and requested that each entity respond by April 30, 2021. Between May 27, 2021, and June 2, 2021, the Task Force held three hearings to provide responsive parties the opportunity to discuss lessons learned from the February winter storms, and to allow the Task Force members to ask questions regarding the responsive party's pre-filed written testimony and any oral testimony provided at the hearing. Attached and marked for identification purposes as "Appendix B" are Task Force Meeting and Hearing Materials.

This report presents the findings and recommendations of the Task Force after reviewing the testimony gathered through pre-hearing questions and hearings, and all documentation submitted to the Task Force in association with this testimony.

A copy of this report was delivered to each entity named in Section V.

IV. REVIEW OF LESSONS LEARNED DURING THE FEBRUARY 2021 WINTER WEATHER EVENT

Pursuant to EO 21-05, Governor Asa Hutchinson's first directive to the Task Force was to review the lessons learned from the February winter storms, including lessons from surrounding states and information gathered by hearing testimony from the following:

- The Chair of PSC, or his or her designee;
- A representative of MISO;
- A representative of SPP;
- A representative of Entergy;
- A representative of AECC;
- A representative of SWEPCO;
- A representative of OG&E;
- A representative of Empire;
- A representative of AMPA;
- A representative of CenterPoint;
- A representative of AOGC;
- A representative of Black Hills;
- A representative of AEEC;
- A representative of the Arkansas State Chamber of Commerce;[1]
- The Executive Director of AEF, or his or her designee;
- The President of AIPRO association, or his or her designee;
- Additional citizens, as the Task Force deems necessary, with knowledge and expertise in energy and environmental matters; and
- Additional citizens, as the Task Force deems necessary

The Task Force received written and/or oral testimony from the following entities:

1. Chairman Ted Thomas of PSC – Oral and Written
2. Attorney General's Office – Oral and Written
3. MISO – Oral and Written
4. SPP – Oral and Written

[1] Arkansas State Chamber of Commerce was sent a request to provide testimony to the Task Force, but the entity did not provide written or oral testimony to the Task Force.

5. AEF – Oral and Written
6. AEEC and AGC – Oral and Written
7. AF&PC – Oral and Written
8. Quattlebaum – Oral and Written
9. Black Hills – Oral and Written
10. CenterPoint – Oral and Written
11. AIPRO - Oral
12. AMPA – Oral and Written
13. Empire – Oral and Written
14. OG&E – Oral and Written
15. SWEPCO – Oral and Written
16. AECC – Oral and Written
17. Entergy – Oral and Written
18. EPN and Jackson Walker Law Firm – Oral and Written
19. PPGMR – Oral and Written
20. Ozark Mountain Petroleum, Inc. – Oral and Written
21. Craft Propane Inc. – Oral and Written
22. NGL Supply Wholesale – Oral and Written
23. APGA and Island Energy – Oral and Written
24. Enable Midstream - Oral
25. Summit Utilities - Oral
26. AOGC
27. CHS, Inc. – Oral and Written
28. Enterprise Products Partners LP - Written
29. AGA - Written

Attached and marked for identification purposes as "Appendix C" are the written responses received by the Task Force to pre-hearing testimony questions and supporting documents provided to the Task Force.

A. Communication

1. Notification of Potential for Curtailments

   Across the board, electric and gas utilities engaged in extensive outreach efforts to notify their customers of the potential for curtailments and the need to conserve energy during the February 2021 winter weather event. Local utility companies employed a variety of communication strategies, including: media notices, press releases, social media, text messaging, email, and webpage updates. Nevertheless, a few natural gas customers reported that they were unaware that they were being curtailed until a technician showed up to turn off their gas. In other cases, customers received notices that their home or business was part of a circuit selected for curtailment after the outages had already begun. In their testimony to the Task Force, utility company representatives provided lessons learned on how they could potentially improve their process for notifying customers of curtailment based on the challenges experienced during the February 2021 winter weather event.

One challenge to the notification process identified by representatives from CenterPoint and AOGC during the February 2021 winter weather event was contacting the right person within large industrial organizations. This challenge presents an opportunity to be better prepared in the future by updating contact information more frequently. In addition, CenterPoint representatives suggested that increasing the number of staff to make phone calls would help improve the notification process if a future energy emergency arises.

Another challenge identified by Entergy representatives was the short-time frame between being informed by the RTO about the directive to initiate curtailments and when the first curtailment commenced. This short time frame made it difficult for utility companies to provide advance notice to individual customers that their power would be curtailed. Entergy representatives stated that the Company has taken steps to enable it to be better able to direct communication about which customers are next to experience outages if they were to identify and maintain a contact list for the customers served on each of their circuits. Additionally, Entergy representatives noted that it may continue to be difficult to notify customers on the first circuits curtailed during a coordinated outage directed by an RTO but that it would be possible to provide advance notice to customers on the subsequent circuits that would be curtailed in those events.

2. Notification of Shifts in Pricing

Some energy consumers and municipal utilities were unaware and surprised by high energy bills after the February 2021 winter weather event. Multiple energy consumer representatives indicated that they had no real-time indication of prices. If there had been a system in place to notify them when energy prices exceeded a specified threshold, they testified that they may have chosen to curtail operations voluntarily instead of continuing to operate.

This challenge presents an opportunity for energy consumers and their suppliers to add additional language to their private service contracts to implement a system that would provide for real-time price signaling to consumers. Various presenters noted that both MISO and SPP provide timely information on the wholesale prices of electricity on their web pages. Additionally, presenters noted that the market prices for natural gas are also publicly available. Electric and natural gas utilities file their energy cost rates with PSC, and those rate schedules are available on PSC web page. Municipal electric utilities that purchase wholesale electric capacity and energy may want to discuss opportunities to obtain price information from their wholesale providers.

3. Availability of Special Needs Affidavits

Prior to the February 2021 winter weather event, some natural gas consumers were unaware of the need to file a human-needs affidavit certifying that they have a facility with human-needs usage requirements. Examples of human-needs customers include hospitals, housing, greenhouses, poultry farms, and schools (except those with central boiler plants for heating and an alternative fuel source). Human-needs customers are exempt from curtailment. The human needs affidavits are a component of the interstate natural gas pipeline companies with FERC approving tariffs to their customers who either are or who serve human needs customers. Those transactions are not subject to any regulation at the state level.

AGC representatives also discussed the availability of special needs affidavits for plant protection. When gas supplies are limited, some pipelines may reduce their load by reducing the flow of gas to a transportation customer (a customer who buys directly from the pipeline) to the minimum necessary to keep equipment from freezing if the customer has a special needs affidavit, plant protection affidavit, or both on file with the pipeline. Otherwise, the customer may be completely shut off from gas or incur substantial penalties for burning gas during a curtailment event. Being completely shut off from gas may damage equipment for some transportation customers.

Representatives from AEEC, AGC, AF&PC, Quattlebaum, and Black Hills suggested that more education about human-needs, special needs, and plant-protection affidavits would be beneficial to prevent those facilities serving human needs or for which curtailment would damage equipment from being curtailed because they don't have an affidavit in place.

B. Adequacy of Existing Energy Infrastructure

In their testimony to the Task Force, some representatives provided lessons learned about the challenges the existing energy infrastructure faced during the February 2021 winter weather event.

1. Natural Gas

Testimony from representatives of multiple entities indicated that the shortage of natural gas supply during the February 2021 winter weather event was due in large part to freeze-offs at natural gas production facilities in Texas and Oklahoma that deliver natural gas for use in Arkansas and other states. At the same time supply of natural gas was reduced, demand for natural gas for heating and electricity generation experienced unprecedented winter peaks. The supply and demand imbalance contributed to spiking prices for natural gas and the need for natural gas curtailment and short-term, localized, and controlled electric load shedding events. Following review of the pre-filed written testimony, and listening to the testimony of those who appeared before the Task Force, it is evident that the natural gas industry in the state performed remarkably well under the most extreme circumstances. All personnel working in the natural gas industry here in Arkansas should be commended for their performance and success at preserving enough supply to be used for meeting human needs.

a. Preparation of Natural Gas Production Facilities for Freezing Conditions

The natural gas production facility freeze-offs that occurred in Arkansas appear to be the result of insufficient weatherization of Arkansas natural gas wells and compressors in freezing temperatures experienced during the February 2021 winter weather event. For example, the representative from AIPRO testified that many of the natural gas producers in Arkansas worked to borrow heater facilities for their systems. However, Arkansas producers were only able to access approximately sixty heating units; whereas, there are thousands of wells in the state. Therefore, producers prioritized top producing wells for weatherization during the February 2021 winter weather event. In addition, road closures due to snow and ice also imposed a difficulty for producers to access wells. While additional heating equipment may have helped maintain production of additional wells, the AIPRO representative suggested that the cost of preparing for a fifty year event may not be economically feasible for producers.

A MISO representative suggested that setting winter weatherization standards to protect generation and fuel supplies from freezing conditions would mitigate risk of diminished generation and supply during rare winter weather events. If developed, such standards would be established in coordination between RTOs and their members. However, increased weatherization of wells and well compressors would come with increased costs for equipment that are not needed on a routine basis, and those costs need to be weighed against the potential benefits.

b. Natural Gas Supply Streams and Storage

Although Arkansas has ample natural gas resources and is a net exporter of natural gas, some of the natural gas used in Arkansas is produced out of state. The Fayetteville Shale gas development in Arkansas in the mid-2000s occurred after infrastructure to bring natural gas into Arkansas had already been established. Therefore, the majority of natural gas produced within the state is transported out of the state to the east. This dependence on interstate supply for natural gas obtained from un-weatherized wells in Oklahoma and Texas resulted in a shortage of supply to Arkansas utilities in February 2021.

Examples of affirmative measures that could be taken to reduce Arkansas's dependence on interstate natural gas supply include development and connection to additional supply basins, additional local supply or local storage capability, and improved or new interconnects for pipelines. A representative from CenterPoint suggested that such measures add incremental reliability. However, the improved reliability from these measures would come at a cost to the utility companies, customers, and upstream providers and those costs would need to be evaluated relative to any potential benefits.

Local storage of natural gas, either at storage facilities along the pipeline or at industrial or utility company sites where the natural gas is used, can mitigate temporary imbalances in production and demand. For example, a Black Hills representative described additional storage facilities approved by PSC in 2015 as a means to allow utility companies and other providers to meet demand during the February 2021 winter weather event. However, the low cost of natural gas means that onsite storage solutions are not economically favored without outside incentives.

2. LP-Gas (Propane)

Based on a review of the testimony provided, the month of February in 2021 may have been the worst month in the history of the LP-Gas industry in Arkansas. The freezing temperatures that affected the natural gas pipelines also affected the LP-Gas pipelines, which caused terminals in the area to go off-line. Unlike natural gas, from the terminal to the end user, LP-Gas is delivered by truck, so deteriorating road conditions prevented transport deliveries. In addition to this, NGL Energy Partners, LP made a business decision in 2020 to de-commission a million-gallon storage terminal in the central part of the state. This required transporters to travel further distances to pull more LP-Gas from outside the state. By February 20, 2021, there were several LP-Gas dealers that had little or no supply of propane. The LP-Gas industry personnel should be commended for their tireless effort to make sure their customers had heat in their homes during this challenging time period.

The Task Force heard testimony from representatives in the LP-Gas industry regarding constraints on propane supply and distribution during the February 2021 winter event. Prior to the event, supply was already constrained due to higher demand during the winter than in summer, creating an imbalance in pipeline allocations. The LP-Gas needs during the events exceeded forecasted demand and pipeline shipment of ordered LP-Gas from Texas was delayed. In addition, LP-Gas supply from the Valero Refinery was unavailable during the February 2021 winter weather event due to a small explosion at the refinery. Some LP-Gas that was ordered by dealers was not delivered. There are also no LP-Gas terminals or other supply in the western part of Arkansas. As a result of the supply interruptions and lack of supplemental local supply, LP-Gas carriers traveled farther to obtain supply to meet demands in Arkansas. Further complicating matters, hazardous road conditions made delivery of LP-Gas by truck more difficult.

LP-Gas industry representatives explained that lifting the hours of service requirements for LP-Gas drivers during the emergency enhanced their ability to serve customer demand during the February 2021 winter weather event. LP-Gas industry representatives suggested that lifting the requirements sooner in anticipation of an event would be beneficial. Additionally, temporary exceptions to gross vehicle weight limits for LP-Gas transports in anticipation of extreme weather events was recommended by LP-Gas industry representatives to enhance transport of propane supply.

LP-Gas industry representatives suggested that additional propane storage at retail locations and additional terminals might mitigate supply disruptions and insufficient pipeline allocation. A representative from Ozark Mountain Petroleum, Inc. suggested that strategic placement of rail facilities around the state would help secure adequate propane supply. However, additional storage also comes with additional cost. APGA representatives suggested reducing taxes and fees as an incentive to invest in storage and equipment. In addition, ensuring that existing storage is kept full would also help to mitigate potential supply disruptions.

3. Electricity

The coordination among PSC, electric utility companies, and RTOs helped Arkansas manage the challenges experienced during the February 2021 winter event. Arkansans benefited from the participation by Arkansas utilities in two RTOs that were able to pull electricity from a wide geographic region with a diverse energy resource mix. Utility companies and RTOs had well-rehearsed plans in place prior to the event to effectively disseminate information about conservative and emergency operating conditions that allowed them to react quickly to maintain the reliability of the grid. The electricity industry personnel should be commended for their tireless effort to power Arkansas homes during the February 2021 winter weather event.

a. Performance of Existing Electric Generation Fleet

Electric industry representatives testified that each fuel source within the existing electric generating fleet experienced some challenges during the February 2021 winter weather event, which further constrained energy resources. However, the electric industry representatives noted that Arkansas utilities' diverse fuel resources and participation in the MISO and SPP RTOs significantly limited the number of outages actually experienced during the event. An Empire representative explained that they had issues across their generating fleet, including coal plants that had frozen coal or tripped offline, low gas pressure issues on some natural gas thermal generators, and some frozen turbines on wind farms that were not winterized. A SPP representative confirmed that both coal and natural gas generating facilities in the region experienced weather-related challenges that affected the performance of those units relative to how those resources are accredited for reliability purposes. Although wind turbines were not very productive during the period of the February winter storm, an SPP representative confirmed that this lack of productivity was consistent with forecast.

A MISO representative explained that winterization of generators, in addition to fuel supply winterization, might mitigate risks associated with conditions like those experienced during the February 2021 winter weather event. There are currently no standardized winterization criteria in the MISO region. However, the MISO representative suggested that such criteria would need to be assessed by MISO and its members. The MISO representative also suggested that there would be a need for an entity to monitor or verify weatherization of the generation fleet. Further, the MISO representative noted that it would be essential to evaluate the cost associated with weatherization of the generation fleet and whether those expenditures would be reasonable and appropriate relative to the expected benefits.

The MISO representative also explained that the February 2021 winter weather event, as well as other maximum generation event days that have occurred outside of the summer months in recent years, suggests that resource adequacy planning should be refined. Past practice was to plan for adequate resources to meet the projected summer peak. The MISO representative explained that changing to a seasonal resource adequacy construct could help account for seasonal variation in fuel availability and generation capability.

b. Performance of Existing Transmission Infrastructure

Some of the load shedding events during the February 2021 winter weather event were a result of transmission constraints rather than lack of energy. However, as the electric utility and RTO representatives noted, there were limited customer interruptions both in number and duration during the event. At times during the winter weather event, overloading of transmission lines and regional transfer limits hindered the ability to move energy to specific areas where it was needed. In addition, an Entergy representative also explained that transmission constraints caused a derate at one of the units at the Nuclear One facility in Arkansas for a few hours, which was otherwise performing exceptionally. Entergy Arkansas representatives further noted that its investment in its transmission infrastructure over the past several years helped ensure reliable electric service and limited the impact of the event.

Although there were localized transmission constraints, the ability for MISO and SPP to pull energy from other regions in the Eastern Interconnect dramatically reduced the impact from weather-related challenges such as insufficient gas supply and generating units that tripped offline in the MISO and SPP regions during the February 2021 winter weather event. The MISO representative explained that the addition of new transmission capacity and improved interregional coordination and interconnection would bring significant efficiency and reliability benefits. The PSC Chairman, as well as the electric utility and RTO representatives, all noted that participation in the MISO and SPP RTOs significantly contributed to reliable performance during the event and helped limit the number and duration of any outages.

c. Diversity of Generation Assets

Several entities provided testimony about how diversity of types and geographic location of generating assets provide a significant reliability benefit. Both MISO and SPP representatives explained that the interconnection of RTO regions on the Eastern Interconnect was a tremendous benefit to reliability because they were able to pull energy from areas that were not severely impacted by the February 2021 winter weather event. Both RTOs have a diverse mix of generation asset types. As noted by the PSC Chairman and the electric utility and RTO representatives, the diverse fuel mix in the Arkansas generation portfolio mitigated the number of and duration of outages.

While the majority of testimony pointed to a natural gas supply shortage used for electric generation due to freeze-offs and transmission constraints as the primary cause of the power shortage during the February 2021 winter weather event, EPN representatives cited a different cause. EPN representatives opined that the primary cause of the power shortage during the February 2021 winter weather event was "Arkansas's contractual ties to RTOs that have collectively closed 60 baseload power plants (over 22,000 MW) in the past five years" and the replacement of those plants with intermittent generating resources. The EPN representatives suggested that, if those baseload power plants had not been retired, the region would not have had the outages experienced during the February 2021 winter weather event. However, the electric utility and RTO representatives all provided testimony that the outages in Arkansas and in the MISO and SPP regions were limited in numbers and duration during the event. Those representatives further noted that the diverse fuel mix of Arkansas's generation fleet, investments in generation, transmission, and distribution assets, as well as participation in the MISO and SPP RTOs helped Arkansas manage the storm and mitigate outages.

C. Planning for Reliable Energy

There were numerous suggestions regarding how to ensure the reliability of future energy infrastructure. These suggestions touched on transmission, current and planned generation assets, and load management.

1. Transmission

As previously noted, transmission constraints hindered the movement of electricity during the February 2021 winter weather event. The MISO representative explained to the Task Force that transmission expansion in the present could mitigate risks associated with such events, but transmission expansion will become even more necessary to accommodate significant increases in renewable energy generation and other projected changes to the grid, including electrification of vehicles and other sectors. The MISO representative explained that MISO's plans evaluate additional interconnection, examine load pockets, and work with seams partners to increase coordination. The SPP representative explained that strong transmission interconnections increase their ability to rely on generation in its footprint as well as energy transfers from neighbors to mitigate supply deficiencies during an emergency. Both MISO and SPP have established processes to evaluate the transmission investment needs within their footprints and to make plans to ensure that the investments necessary to maintain a reliable bulk electric system are made by the transmission owners. That process includes participation from the electric utilities, state regulators including PSC, and transmission customers. The MISO and SPP processes are open forums where the investments needed to ensure reliability are discussed and evaluated. Further, many of the electric utilities' transmission investments require PSC review and approval in an open, public process.

2. Current and Planned Generation Assets

Arkansas investor-owned utility companies participate in RTOs that operate a market-based system for directing dispatch of generation assets within their region. RTOs are responsible for ensuring the reliability of the high-voltage electric transmission system and directing dispatch of generation resources to ensure the reliable and cost-effective delivery of energy. RTOs use an energy market to direct dispatch of energy resources. The energy market takes into account forecasted energy needs, system constraints, state laws, and operation profiles of different types of generation assets to manage risk and deliver least-cost energy. In addition, the RTOs have established procedures for ensuring the reliability of the electric grid in preparation for potential events and during energy emergency events. Additionally, pursuant to statutory authority in Arkansas, PSC conducts reviews of electric utility resource plans every three years. Those plan reviews are conducted in an open forum that allows for participation and input from stakeholders. Those "integrated resource plans" help utilities plan for the generation investments needed to meet the load that they serve.

The Task Force heard different perspectives on the maintenance of current generation assets and how to direct investment in new generation capacity. The electric utility company and MISO representatives indicated that they were in the process of re-evaluating planning and market products to meet the reliability imperative, taking into consideration the evolving grid, and to move to a seasonal construct for resource adequacy determinations. EPN representatives recommended enacting legislation and rules in Arkansas to direct retention of and investments in baseload thermal generation. However, PSC resource planning process described above provides a forum to evaluate the electric utility plans for generation needed to meet their load. Furthermore, the Arkansas General Assembly enacted Act 694 during the 2021 session, which requires electric utilities to consider the costs and benefits of extending the life of existing generating resources as part of the established resource planning process.

An SPP representative explained that Arkansas benefits from vertically integrated regulatory systems in Arkansas and in other states whose utilities participate in SPP and MISO markets. In deregulated systems without a capacity market, like ERCOT, the cheapest generation is built first. In ERCOT, the cheapest energy resource is wind, which often bids into the market in negative prices due at least, in part, to the impact of the production tax credits for wind generation facilities. Regulated systems allow the states to enact policies to direct prudent investments in energy infrastructure with a focus on reliability as well as economics because utility companies must justify investments to PSC in order to earn a return on their investment from ratepayers. The experience of the Arkansas electric utilities that are members of the MISO and SPP RTOs during the winter weather event was significantly different than the participants in ERCOT.

EPN representatives suggested that existing baseload dispatchable generation planned for cessation of operations should be retained and used for operating reserve. EPN specifically mentioned three power plants in Arkansas (one natural gas and two coal plants) where Entergy plans to cease operations or cease use of coal. The Entergy representatives explained that, given the required investments needed for these facilities that are nearing the end of their useful lives, maintaining those units as a backup would not be efficient or cost-effective, and there are better alternatives. The Entergy representatives suggested it would be more cost-effective to invest in newer, more efficient technologies that can serve as longer-term resources to customers.

EPN representatives also suggested that any new intermittent generation assets should be backed with a firm power purchase contract to purchase from dispatchable thermal generation assets. This resource adequacy approach was also mentioned in a report provided by MISO.[2] The MISO report suggested that they would need to consider how to incorporate fuel assurance requirements in a cost-effective manner when such a resource may only be needed a few times a year. PSC's established resource planning process provides an opportunity for evaluating the needs for generating resources, including whether new resources are cost-effective and how they affect reliability. Further, the MISO and SPP RTO planning processes under the FERC and NERC regulations require the participating electric utilities to have adequate generation to meet their load plus an adequate reserve margin. These requirements help ensure that there are adequate resources to meet the needs of Arkansas customers.

MISO provided the Task Force with a detailed report of lessons learned with regards to systems planning, as well as other MISO operations, that the RTO plans to implement in coordination with market participants and other stakeholders.[3] Specifically, MISO plans to move to a sub-annual (4-season) resource adequacy construct and implement changes to its resource accreditation criteria to better reflect resource availability during hours when the system is most in need and during extreme weather events. In its seasonal assessments, MISO plans to focus more attention to extreme scenarios (high loads and high outages). MISO explained that these changes should provide an incentive to

[2] "The February Arctic Event: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative" included in Appendix C of this Report.
[3] MISO provides a comprehensive list of Lessons Learned and Actions to Address the Lessons starting on page 48 of it's "The February Arctic Event: Event Details Lessons Learned and Implications for MISO's Reliability Imperative" report provided to the Task Force during the May 27, 2021, hearing.

resource owners to invest in winterization, fuel assurance, and other means of ensuring resource availability. This market-based approach mitigates risk while providing flexibility to keep the cost of the bulk electric system low. The RTOs continue to evaluate their resource adequacy constructs as the energy resource mix and risk profiles evolve. The PSC and RTO resource planning processes provide open forums to evaluate the electric utility industry's actions to ensure that their customers receive reliable electric service at reasonable rates.

3. Load Management

The goal of energy resource planning and operations is to reliably match supply of energy with demand for energy. Many of the representatives spoke to energy supply management, but demand-side management also can be used to balance supply and demand. All of the electric and natural gas utilities offer demand response programs.

For example, Entergy offers a Smart Direct Load Control Pilot Program as part of its energy efficiency programs. The program allows customers to opt in to a programmable thermostat that the utility company can adjust by a few degrees to reduce load during summer peaks between June 1 and September 30 each year. In exchange for the utility company's ability to perform this service, customers get a free smart thermostat, which can save them money by reducing heating and cooling when no one is home, and an annual enrollment incentive to encourage continued participation.

Interruptible tariffs also provide a mechanism for load management. AEEC testified that many industrial and agricultural customers take electric services on interruptible tariffs. An interruptible tariff makes the customer subject to curtailment in the event of a utility's peak load exceeding the available capacity. In exchange, these customers receive a discount on rates. Curtailment for customers on interruptible tariffs helped reduce the need for load shedding during the February 2021 winter weather event.

PSC Chairman Ted Thomas suggested further exploration of demand response and ensuring that demand response programs create appropriate price signals to incentivize consumers to voluntarily reduce load when needed. Demand response can also be used to address the intermittent nature of many of the renewable generation assets that are being brought online by matching intermittent supply with intermittent demand. PSC has an open proceeding to consider existing and planned demand response offerings by the electric utilities in Arkansas. The open PSC proceeding provides an open forum to address demand response programs in Arkansas.

V. RECOMMENDED ACTIONS TO ENSURE ADEQUATE SUPPLY OF CRITICAL ENERGY SOURCES DURING EXTREME EVENTS

A. Creation of an "Energy Resources Council"

The Task Force recommends creating an "Energy Resources Council." The Energy Resources Council would meet at least once annually to facilitate technical and policy discussion among regulators and energy stakeholders and would work to develop and maintain educational materials on best practices regarding preparation and communication in advance of and during events that may disrupt supply of critical energy resources. The list below provides recommended potential organizations for the Governor to nominate as Energy Resources Council members:

- Representative(s) from E&E;
- Representative(s) from Commerce;
- Representative(s) from PSC;
- Representative(s) from the Arkansas Attorney General's Office
- Representative(s) from electric and gas utility companies;
- Representative(s) from the Natural Gas and LP-Gas industry;
- Representative(s) from the MISO and SPP; and
- Representative(s) from community and business organizations, such as the Arkansas State Chamber of Commerce, AF&PC, AEEC, and AGC.

The Task Force also recommends that E&E host educational materials developed by the Energy Resources Council on its website and coordinate logistics for the annual meetings. Further, the Task Force recommends that RTOs, APSC, and utilities share with the Energy Resources Council any reports or other publications that quantify the outcomes of efforts these entities are undertaking to address lessons learned during the February 2021 winter weather event.

B. Creation of an "Energy Disruption Preparedness" Tool Kit

The Task Force recommends creating a webpage to serve as a central research location for information related to energy resources in the state. This central location would provide access links to the various utility companies and expert groups and provide a tool kit for best practices for preparedness for potential energy disruption events. E&E would host the tool kit and coordinate discussions with the energy industry participants on content and updates to the tool kit. This coordination would occur in conjunction with the proposed Energy Resources Council or in some other forum.

Examples of tool kit contents might include:

- Best Practices for Preparing A Business' Operation for a Potential Energy Disruption
    - Creating a facility-specific plan including consideration of:
        - Whether back-up fuel or generation is necessary;
        - What are minimum energy or fuel requirements to protect equipment from damage;
        - What level of energy or fuel, if any, is necessary to sustain human needs functions;
        - Who is responsible for making decisions to voluntarily curtail operations to conserve energy and reduce exposure to price surges;
        - Whether a human needs or plant protection affidavit should be filed with the energy supplier;
    - Electric and natural gas utilities that take service from interstate natural gas pipeline companies should submit a human needs affidavit for their operation pursuant to the pipeline company's FERC tariff:
        - Educational materials about what a human needs affidavit is and why it is important to keep a human needs affidavit on file if a portion of an energy provider's operations serve human needs;
        - Links to relevant FERC tariffs that establish the legal foundation;
    - Ensuring fuel and electricity suppliers and utilities know who to contact in the event of an energy disruption event;

- Best Practices for Communication in Advance of and During an Energy Disruption Event:
    - Implement a regular, periodic review by utility companies of the appropriate contacts for customers that may be curtailed during an energy disruption event;
    - Identify customers and ensure up-to-date contact information for each circuit so that the appropriate customers can potentially be notified promptly after a decision is made about a planned outage that is necessary for the stability of the grid;
    - Create a list of the call center numbers and other applicable contacts for each utility company so that state agencies can refer citizens to this list if there are concerns during an energy disruption event;
    - Review procedures and protocols for advance warning of service interruptions for customers served on interruptible rate schedules, coordinated outages, or other energy curtailments;
    - Reach out to PSC, E&E, Commerce, and prominent community business organizations to amplify the message to conserve energy when needed;
    - Include in-messaging implications of an energy disruptive event, such as the potential for outages and any associated price increases;

- Information about energy pricing (links or embedded tools):
  - Daily Natural Gas Spot Prices: https://fred.stlouisfed.org/series/DHHNGSP#;
  - MISO Locational Marginal Price Data: https://www.misoenergy.org/markets-and-operations/real-time--market-data/real-time-displays/;
  - SPP Price Contour Map: https://pricecontourmap.spp.org/pricecontourmap/; and
  - Best practices for ensuring that energy contracts provide for notification of price spikes, opportunities for voluntary curtailment and to direct customers to the public sources for wholesale electricity prices and natural gas prices so customers can monitor the prices and adjust their consumption accordingly.

The Task Force recommends sending out social media, press releases, and other methods of disseminating the availability of the tool kit once it is launched and at least twice a year each year thereafter in advance of the summer and winter seasons. The Task Force also recommends disseminating information about the availability of the tool kit when extreme weather events are forecasted.

C. Areas for Additional Consideration and Study

The Task Force notes that there are other items that may warrant further consideration within the appropriate existing forums, where they exist, to continue monitoring whether any additional actions may be appropriate. The following are potential areas identified by the Task Force upon reviewing testimony received. However, before taking actions under one or more of the following, the Task Force recommends a robust evaluation of the anticipated ratepayer impacts, environmental impacts, reliability impacts, and economy-wide impacts of any action.

1. The Task Force recommends that PSC continue its examination of demand-response programs in Arkansas and evaluation of whether it is in the best interest of Arkansas customers to expand those programs. The Tasks Force suggests that PSC consider whether it would be beneficial to expand the demand-response programs that are included in electric and natural gas utility rate schedules and financial incentives to customers for the widespread installation of demand-response technology for air conditioning, heating, and water heaters above and beyond the measures included in current utility company energy efficiency plans. Alternatively, or in addition, the Task Force recommends that the Energy Office within E&E consider whether it is beneficial to provide rebates for installation of demand-response equipment if state or federal funding becomes available. In addition to considering the potential for providing incentives to invest in demand-response technology, the Task Force recommends that PSC and E&E consider producing and distributing educational materials on the value of demand response for both reliability and cost-savings.

2. The Task Force recommends that PSC, the MISO and SPP RTOs, and E&E's Arkansas Oil and Gas Commission evaluate whether it is reasonable and cost effective to develop

standard criteria for weatherization of natural gas supply infrastructure and electric generation infrastructure in Arkansas. As part of PSC's resource planning process, a continued evaluation of the investments is needed to ensure adequate electric and natural gas supplies are available in Arkansas. The Task force recommends exploring potential opportunities to coordinate with Oklahoma, Texas, and the private sector to identify key components of the electrical, natural gas, and LP-Gas supply system that need protection from extreme cold and to examine whether there are cost effective opportunities to implement weatherization of these components. The Task Force recognizes that it will be beneficial to take advantage of the established procedures of PSC, MISO and SPP RTOs, and other state entities to pursue these evaluations.

3. The Task Force recommends the evaluation of investments in electric generation, including back-up generation, transportation, transmission, distribution, and storage assets that improve the reliability of Arkansas's electric infrastructure. This evaluation can be accomplished through the existing PSC and MISO and SPP RTO processes. The PSC's resource planning proceedings provide an open forum to consider the resource plans of the electric utilities. Further, individual utility proceedings to obtain approval of specific generation investments are also public opportunities to evaluate planned investments.

   Continued participation by PSC and other Arkansas stakeholders in RTO stakeholder processes provides value to Arkansas energy customers at no additional cost. The RTO stakeholder process ensures a rigorous evaluation of how to address reliability needs at the least cost. The RTOs have already begun implementing their lessons learned, including: evaluations of transmission gaps, changing to a seasonal construct for resource adequacy planning and capacity accreditation, and other measures for improving reliability.

4. The Task Force recommends that Arkansas's congressional delegation remain engaged in national policy discussions with respect to future tax credits for energy resources. Currently, there are investment tax credits for solar generation and production tax credits for wind generation. Congress should evaluate whether there are opportunities to provide incentives, such as tax credits, for the development and scaling of novel generation and storage technologies. The Task Force recommends working with Arkansas's Congressional delegation to evaluate whether changes to energy tax credits are appropriate and to encourage development of legislation to implement any changes determined appropriate.

5. The Task Force recommends that PSC, RTOs, E&E's Arkansas Oil and Gas Commission, and the LP-Gas Board consider whether it would be appropriate to implement any incentives for measures that could improve reliability in the form of financial incentives, formal recognition, expedited permitting, new rate structures and service offerings, or waiver of fees. The Task Force recommends evaluating whether it is technically feasible and cost effective to implement incentives for one or more of the following measures that could improve the reliability of Arkansas and regional energy

infrastructure:

- Transmission upgrades and expansion, particularly in load pockets and at RTO seams;
- Increased deployment of energy storage technologies, such as pump storage and battery storage;
- Increased deployment of back-up generation or dual-fuel generation that is capable of using a different fuel, such as diesel, LP-Gas, or liquefied natural gas, instead of the primary fuel used for generation;
- Addition of strategically-placed supply pulling points for LP-Gas, including pipeline terminals, rail terminals, and transloading facilities;
- Addition of natural gas storage facilities; and
- Addition of retail storage for LP-Gas.

The Task Force suggests that evaluating implementation of incentives for the electric energy infrastructure can and should occur as part of the established PSC resource planning process and the established processes of the MISO and SPP RTOs. Meetings of the proposed Energy Resources Council could serve as a forum for sharing ideas with respect to best practices for resource planning among electricity, natural gas, and LP-gas industry representatives and regulators.

6. The Task Force recommends that E&E evaluate whether it is reasonable and cost effective to expand current recognition programs to include reliability similar to the Arkansas Energy and Environment Stewardship Award ("ENVY"), the Arkansas Energy and Environment Technology Award ("TECHe"), the Energy Excellence Award ("E2"), and Quest Science Award that E&E uses to highlight what Arkansas companies are doing in the areas of sustainability, innovative technology, and energy and environmental stewardship.[4]
7. The Task Force recommends that the LP-Gas Board examine whether it is technically feasible and cost effective to expedite inspections of new retail and terminal-level LP-Gas storage and waive fees to promote the addition of LP-Gas storage, pipeline terminals, rail terminals, and transloading facilities.
8. The Task Force recommends that E&E's Arkansas Oil & Gas Commission coordinate with the Arkansas Geological Survey and representatives from the natural gas producers and natural gas utilities to evaluate whether there are any additional geological formations or existing abandoned gas fields in the state capable of storing natural gas or propane. If additional sites suitable for storage are identified, the Task Force recommends that the state work with stakeholders to evaluate the technical and economic feasibility of incorporating the sites into Arkansas's energy infrastructure.

[4] https://www.adeq.state.ar.us/poa/enterprise-services/awards/

9. The Task Force recommends that the appropriate stakeholders evaluate whether there are any additions or revisions to Arkansas statutes to help promote investments and assist in providing reliable energy resources for the state in the future. The stakeholders should evaluate whether any state policy could be enacted through legislation or adopted under state agency rules if authorizing legislation already exists.

10. The Task Force recommends that the Arkansas Department of Transportation coordinate with E&E, PSC, utility companies, and county and local governments to identify priority routes for delivering diesel fuel used for backup generation and propane used for heat. The stakeholders should evaluate whether it would be beneficial to develop a communications protocol to determine whether these routes should be among the first cleared during winter weather events that threaten to disrupt energy supply and delivery. The coordinated effort should include development of a plan for ensuring that the identified routes are kept clear during an energy disruption event.

11. The Task Force recommends that PSC coordinate with the electric and natural gas utility companies to ensure that there are appropriate and adequate communications plans to notify customers of potential coordinated outages or other interruptions of service during weather events. Further, PSC should coordinate with the utility companies to determine whether it is necessary to develop communications advising customers of potential prices increases caused by weather events, including consideration of the costs of developing such communications and notifications.

12. The Task Force also recommends that PSC evaluate its rules and tariffs and consider whether it is reasonable and necessary to require utility companies to notify a customer of an impending curtailment so that the customer may take steps to protect equipment and plan for changes to its operations during the curtailment, including evaluation of the costs and feasibility of such procedures, and if the procedures implemented by the utilities are sufficient.

13. The Task Force recommends that the appropriate stakeholders consider whether Arkansas should implement policies to extend the human needs-based system for prioritization of natural gas and electricity to all energy resources, including LP-Gas. If outages are necessary to ensure the reliability of the electricity grid or curtailment is necessary due to limited fuel supply or other weather-related electric infrastructure outages, the Task Force recommends that the stakeholders consider what steps are necessary to establish procedures for prioritizing energy to occupied dwellings, natural gas-fired electric generation to serve human needs customers, food supply production, and other commercial and industrial facilities whose operations are necessary to preserve human life, health, and safety, including whether any executive, administrative, regulatory, or legislative action may be required. The stakeholders should also consider what steps are necessary to establish the procedures necessary, after ensuring energy resources are adequate to sustain human needs, to ensure that adequate supplies of energy to businesses and industry that would otherwise suffer damage to equipment or severe economic harm are prioritized.

14. The Task Force recognizes that there may be limited opportunities for prioritization of energy resources for human needs under state authority. However, the Task Force recommends that the appropriate stakeholders evaluate whether it would be appropriate to implement legislation in Arkansas similar to the Louisiana statute that establishes an Emergency Gas Allocation Plan (see Louisiana Code Title 43, Part XI, Subpart 1, Section 143). Implementation of a state law of that nature may assist human needs customers during emergency situations like the February 2021 winter storm event. It may be appropriate to consider opportunities to coordinate with the state's federal delegation to identify opportunities for state and federal regulatory authorities coordination to determine whether to implement new rules or revise existing rules to implement prioritization of human needs. Examples of rules for consideration include requiring prioritization of fuels used for energy to meet human needs, such as LP-Gas and natural gas, in pipeline allocations over other pipeline products. The state and federal regulatory authorities might also consider whether it should be permissible for pipelines to limit allocations on the pipeline for fuels used to support human needs based on nominations during the summer, when less fuel is needed.

15. Pursuant to the Arkansas Emergency Petroleum Set-Aside Act, Ark. Code Ann. § 15-72-801 *et seq*., the Arkansas Energy Office has promulgated rules and regulations for the implementation and operation of the Arkansas state set-aside program. However, the implementation of this program is commenced when the Governor, in his discretion, finds that the program is necessary to manage a shortage of specified petroleum products which threatens the continuation of emergency services and essential industrial or agricultural activities. While the Task Force recognizes that this set-aside program was not applicable during the February 2021 winter weather event, this program may be a resource that could help with energy resource shortage events should they occur in the future. The Task Force believes further discussion of the set-aside program may be warranted in development of implementation priorities.

VI. ACKNOWLEDGMENTS

The Task Force would like to acknowledge and extend gratitude to each of the following persons and organizations that provided written and/or oral testimony to the Task Force:

- Arkansas Attorney General's Office;
- Craft Propane, Inc.;
- AECC;
- AMPA;
- EPN;
- Empire;
- OG&E;
- PPGMR Law, PLLC;
- SWEPCO;
- AEF;
- AEEC and AGC;
- AF&PC;
- Quattlebaum;
- Enterprise Product Partners, LP;
- NGL Energy Partners, LP;
- CHS Inc;
- Ozark Mountain Petroleum, Inc.;
- Black Hills;
- CenterPoint;
- Entergy;
- Ted Thomas (Chair of PSC);
- MISO;
- SPP;
- AIPRO;
- APGA
- Enable Midstream Partners, LP
- Summit Utilities, Inc.
- Jackson Walker LLP
- AOGC
- Island Energy, Inc.

- Dover Dixon Horne PLLC
- AGA

The Task Force would also like to acknowledge the assistance of the following E&E staff in coordinating meetings and correspondence and in preparing documents in support of Task Force objectives pursuant to EO 21-05:

Tricia Treece
Daniel Pilkington
Andrea Hopkins
Donnally Davis
Beth Thompson
Troy Deal
Shane Khoury

APPENDIX A. EXECUTIVE ORDER 21-05

State of Arkansas
Executive Department

PROCLAMATION

EO 21-05

TO ALL TO WHOM THESE PRESENTS COME – GREETINGS:

EXECUTIVE ORDER TO ESTABLISH THE ENERGY RESOURCES PLANNING TASK FORCE

WHEREAS: Recent winter storms revealed vulnerabilities in critical energy resources in Arkansas and the surrounding region; and

WHEREAS: Increased demand and inadequate available supply of critical energy resources such as natural gas, electricity, and liquefied petroleum gas caused Arkansas citizens to suffer service outages and forced Arkansas businesses to close; and

WHEREAS: Preparedness for the provision and allocation of critical energy resources during extreme events is necessary to preserve the health and safety of citizens and protect the critical infrastructure of this state; and

WHEREAS: It is in the best interest of the state and its citizens to evaluate the ability of Arkansas's critical energy resources and infrastructure to withstand extreme events;

NOW, THEREFORE, I, ASA HUTCHINSON, acting under the authority vested in me as Governor of the State of Arkansas, do hereby order the following:

(1) There is hereby created the Energy Resources Planning Task Force, which shall serve as an investigative and advisory body of the Governor.

(2) The Task Force shall be composed of public and private sector leaders with requisite knowledge and expertise to represent the interests of the public, energy sectors, and industry.

(3) The Task Force shall be composed of members appointed by the Governor and shall serve at the pleasure of the Governor. The chair of the committee shall be designated by the Governor. The Commission shall be composed of:

a) The Secretary of the Department of Energy and Environment, or his or her designee;
b) The Director of the Arkansas Oil and Gas Commission, or his or her designee;
c) The Director of the Arkansas Liquefied Petroleum Gas Board, or his or her designee; and
d) The Secretary of the Department of Commerce, or his or her designee.

(4) The members of the Task Force shall have the following duties:

a) Review the lessons learned from the February winter storms, including lessons from surrounding states and information gathered by hearing testimony from the following:
   i. The Chair of the Arkansas Public Service Commission, or his or her designee;
   ii. A representative of the Midcontinent Independent System Operator (MISO);
   iii. A representative of the Southwest Power Pool (SPP);
   iv. A representative of Entergy Arkansas;

v. A representative of the Arkansas Electric Cooperatives Corporation;
vi. A representative of Southwestern Electric Power Company;
vii. A representative of Oklahoma Gas and Electric Company;
viii. A representative of the Empire District Electric Company;
ix. A representative of the Arkansas Municipal Power Association (AMPA);
x. A representative of CenterPoint Energy;
xi. A representative of Arkansas Oklahoma Gas Corporation;
xii. A representative of Black Hills Energy;
xiii. A representative of the Arkansas Electric Energy Consumers (AEEC);
xiv. A representative of the Arkansas State Chamber of Commerce;
xv. The Executive Director of the Arkansas Environmental Federation, or his or her designee;
xvi. The President of the Arkansas Independent Producers and Royalty Owners (AIPRO) association, or his or her designee;
xvii. Additional citizens, as the Task Force deems necessary, with knowledge and expertise in energy and environmental matters; and
xviii. Additional citizens, as the Task Force deems necessary.

b) Make recommendations for actions needed to ensure adequate supply of critical energy sources during extreme events; and
c) Develop priorities for allocation of limited energy resources should supply shortages due to emergency situations necessitate action to preserve life, health, and safety.

(2) The Task Force shall have an initial meeting within seven (7) days of this order and shall meet as necessary to accomplish its objectives. The Task Force shall provide a report of its findings and recommendations to the Governor by September 30, 2021. The Task Force may provide earlier reports and recommendations to the Governor as necessary.

(3) Upon request, the Arkansas Department of Energy and Environment and the Arkansas Public Service Commission may provide staff and other personnel to support the work of the Task Force.

IN TESTIMONY WHEREOF, I have hereunto set my hand and caused the Great Seal of the State of Arkansas to be affixed the 3rd day of March, in the year of our Lord 2021.

Asa Hutchinson

Asa Hutchinson, Governor

Attest:

John Thurston

John Thurston, Secretary of State

APPENDIX B. TASK FORCE MEETING MATERIALS AND MINUTES

ENERGY RESOURCES PLANNING TASK FORCE

Meeting Agenda

March 10, 2021 | 10:00 a.m.

TASK FORCE MEMBERS

Secretary Becky Keogh, Department of Energy & Environment
Secretary Mike Preston, Department of Commerce
Director Lawrence Bengal, Oil and Gas Commission
Director Kevin Pfalser, Liquefied Petroleum Gas Board

AGENDA ITEMS

10:00 a.m.	• Call meeting to order
10:05 a.m.	• Review Executive Order 21-05
10:15 a.m.	• Briefs provided by Task Force members
10:35 a.m.	• Schedule upcoming Task Force meetings and establish format
10:50 a.m.	• Review testimony list
11:05 a.m.	• Review proposed Task Force timeline
11:30 a.m.	• Adjourn meeting

ENERGY RESOURCES PLANNING TASK FORCE

MINUTES

DETAILS

Date and Time: 03/10/2021 | 10:00 am

Location: E&E Headquarters Commission Room

Subject: Initial Meeting

Task Force

Becky Keogh, E&E Secretary, Task Force Chair

Kevin Pfalser, Liquified Petroleum Gas Board Director, Task Force Member

Lawrence Bengal, Oil and Gas Commission Director, Task Force Member

Michael Preston, Commerce Secretary, Task Force Member

Other Attendees

Mitchell Simpson	Jeff LeMaster	Donnally Davis
Daniel Pilkington	Tricia Treece	Beth Thompson
Troy Deal	Shane Khoury	Julie Linck

AGENDA ITEMS

1. Call to Order — Secretary Keogh

Secretary Keogh, as Task Force Chair, called the meeting to order at 10:00 am on 3/10/21. The meeting was paused to provide additional time for transportation and reconvened at 10:12. Secretary Keogh reviewed the Task Force's charge under EO 21-05 and each task member provided opening remarks.

2. Task Force Meetings, Format and Testimony List — Task Force Members

Secretary Keogh introduced a proposal developed by staff to provide questions to identified persons/organizations, collect written testimony, and hold hearings to provide task force members with an opportunity to ask questions about the written testimony.

Director Bengal suggested that in-person meetings make sense for the 4 task force members; however, remote participation should be an option for those required to give testimony if they do not live in the Little Rock area.

Secretary Preston supported the approach of collecting written testimony with a meeting to ask questions. Secretary Preston noted that the written testimony may prompt follow-up questions for the meeting.

Director Pfalser also supported use of Zoom as an option for testimony.

Secretary Keogh introduced the concept of grouping persons/organizations identified for providing testimony to organize meetings and questions to include to guide written testimony.

Director Bengal supported grouping and reflected that this may create synergies for gathering information.

Director Pfalser indicated that there were additional groups not included in EO 21-05 that should be called upon for testimony to ensure that the task force is hearing from the production, storage, transportation, distribution, and the end users of energy. Director Pfalser will provide a list of additional contacts to E&E staff.

Secretary Preston indicated that the list was a place to start, but should be kept fluid.

Secretary Keogh suggested that the questionnaire sent to persons/organizations required to provide testimony include the following question (or similar):
"Are there any other persons or organizations that the task force should hear testimony from relevant to the task force's charge under EO 21-05"?

3. Timeline — Secretary Keogh

Secretary Keogh introduced a proposed timeline developed by staff for developing questions, collecting written testimony, holding meetings, and preparing the report. The task force will reconvene the week of March 22 or March 29 to finalize a list of questions to send to persons/organizations identified for testimony.

4. Adjournment — Secretary Keogh

Secretary Keogh offered the task members an opportunity to make any further remarks and adjourned the meeting at approximately 10:50 am.

ENERGY RESOURCES PLANNING TASK FORCE

Meeting Agenda

March 29, 2021 | 3:00 p.m.

TASK FORCE MEMBERS

Secretary Becky Keogh, Department of Energy & Environment
Secretary Mike Preston, Department of Commerce
Director Lawrence Bengal, Oil and Gas Commission
Director Kevin Pfalser, Liquefied Petroleum Gas Board

AGENDA ITEMS

3:00 p.m.	• Call meeting to order
3:05 p.m.	• Updates from Task Force members
3:20 p.m.	• Discuss proposed timeline and testimony list for hearings
3:35 p.m.	• Discuss list of questions for testimony purposes
4:00 p.m.	• Adjourn meeting

ENERGY RESOURCES PLANNING TASK FORCE

MINUTES

DETAILS

Date and Time: 03/29/2021 | 3:00 pm

Location: E&E Headquarters Commission Room

Subject: Timeline and Testimony Questions

Task Force

Becky Keogh, E&E Secretary, Task Force Chair

Kevin Pfalser, Liquified Petroleum Gas Board Director, Task Force Member

Lawrence Bengal, Oil and Gas Commission Director, Task Force Member

Michael Preston, Commerce Secretary, Task Force Member

Other Attendees

Jeff LeMaster

Donnally Davis

Beth Thompson

Daniel Pilkington

Tricia Treece

Shane Khoury

Troy Deal

AGENDA ITEMS

1. Call to Order Secretary Keogh

Secretary Keogh, as Task Force Chair, called the meeting to order at 3:00 pm on 3/29/21. Secretary Keogh reviewed the Task Force's charge under EO 21-05 and each task member provided opening remarks. Task members noted additional entities that came forward with interest in presenting to the task force.

2. Timeline Secretary Keogh

Secretary Keogh presented a revised timeline with a goal of finalizing questions for pre-filed testimony by March 31, 2021, submitting questions to the identified entities by April 8, 2021, and requesting pre-filed written responses from identified entities by April 30, 2021.

3. Testimony List and Questions Task Force Members

Secretary Keogh presented a revised testimony list including entities identified in the EO and others who requested to present to the task force. The task force discussed whether some of the entities could be represented by an organization that they are a part of. Director Bengal suggested breaking the hearings up into logical groupings of entities. Director Bengal also suggested that the user group be heard first to outline the problems experienced. Task force members committed to reviewing the testimony list, providing suggested edits, and finalizing the list by noon on March 31, 2021.

Secretary Keogh provided task members a list of potential questions for consideration. Task force members supported building off of other investigations and hearings conducted by the Legislature and other state agencies to ensure efficiency and target inquiries toward energy as a resource, potential incentives, transparency, etc. rather than pricing. The task force committed to reviewing the questions, suggesting edits, and finalizing the list by noon on March 31, 2021.

4. Adjournment Secretary Keogh

Secretary Keogh adjourned the meeting at approximately 3:39 pm.

ENERGY RESOURCES PLANNING TASK FORCE

March 29, 2021 | 3:00 p.m.

PROPOSED TASK FORCE TIMELINE

• March 19, 2021	Proposed questions from Task Force members due
• March 29, 2021	Second Task Force meeting to review proposed questions
• March 31, 2021	Finalization of questionnaire
• April 9, 2021	Distribution of questionnaire to interested parties
• April 30, 2021	Questionnaire responses due
• May 2021	Public hearings
• Mid July 2021	Completion of preliminary draft
• August 1, 2021	Proposed draft submitted and followed by 15-day public comment period
• September 15, 2021	Draft final report to Task Force
• September 30, 2021	Final report submitted to the Governor's Office

ENERGY RESOURCES PLANNING TASK FORCE

March 29, 2021 | 3:00 p.m.

TESTIMONY LIST

1. **Public Service Commission (PSC)**
   Contact: Ted Thomas, Commission Chairman
   Phone: 501-682-2051
   Address: 1000 Center Street, Little Rock, AR 72201

2. **Mid-Continent Independent System Operator (MISO)**
   Contact: John Bear, CEO
   Comms Analyst: Christina Ruth
   Phone: 501-244-1500
   Address: 1700 Centerview Drive, Little Rock, AR 72211

3. **Southwest Power Pool**
   Contact: Barbara Sugg, CEO
   Phone: 501-614-3200
   Address: 201 Worthern Drive, Little Rock, AR 72223

4. **Entergy AR**
   Contact: Laura Landreaux, CEO
   Phone: 501-377-4000
   Address: 425 West Capitol, Little Rock, AR 72201

5. **Arkansas Electric Cooperatives of AR**
   Contact: Vernon "Buddy" Hasten
   Phone: 501-570-2200
   Address: 1 Cooperative Way, Little Rock, AR 72209

6. **Southwestern Electric Power Company**
   Contact: Bradley Hardin, External & State Governmental Affairs
   Phone: 479-973-2347
   Address: 101 West Township, Fayetteville, AR 72703

7. **Oklahoma Gas & Electric Company**
   Contact: Sean Trauschke, CEO
   Phone: 405-553-3000
   Address: 321 North Harvey, Oklahoma City, OK 73102

8. **Empire District Electric Company DBA Liberty Utilities**
   Contact: Kelli Price, Spokesperson
   Phone: 417-850-6953
   Address: 1010 8th Avenue, Gravette, AR 72736

9. **Arkansas Municipal Power Association**
   Contact: Travis Matlock
   Phone: 479-271-3135 ext. 2
   Address: 1000 Southwest 14th Street Bentonville, AR 27212

10. **Centerpoint Entergy**
    Contact: David Lesar, CEO
    Phone: 800-992-7552
    Address: 401 West Capitol, Suite 102, Little Rock, AR 72201

11. **AR Oklahoma Gas Corporation (Parent Company Summit Utilities)**
    Contact: Kurt Adams, President and CEO
    Phone: 479-783-3181
    Address: 115 North 12th Street, Fort Smith, AR 72902

12. **Black Hills Energy**
    Contact: Chad Kinsley, Vice President of Operations
    Phone: 1-888-890-5544
    Address: 655 Millsap Road, Fayetteville, AR 72703

13. **AR Electric Energy Consumers (AEEC)**
    Contact: Steve Cousins
    Phone: 501-570-2200
    Address: 1 Cooperative Way, Little Rock, AR 72209

14. **AR State Chamber of Commerce**
    Contact: Randy Zook, President and CEO
    Phone: 501-372-2222
    Address: 1200 West Capitol, Little Rock, AR 72201

15. **Arkansas Environmental Federation (AEF)**
    Contact: Ava Roberts
    Phone: 501-374-0263
    Address: 415 North McKinley, Suite 835, Little Rock, AR 72205

16. **Arkansas Independent Producers of Royalty Owners Association (AIPRO)**
    Contact: Rodney Baker
    Phone: 501-975-0565
    Address: 1491 West Capitol Avenue, Suite 440, Little Rock, AR 72201

17. **Quattlebaum Law Firm**
    Contact: Michael Heister
    Phone: 501-379-1700
    Address: 111 Center Street, Suite 1900, Little Rock, AR 72201

18. **Mitchell Williams Law Firm**
    Contact: Stuart Spencer
    Phone: 501-379-1700
    Address: 425 West Capitol Avenue, Suite 1800, Little Rock, AR 72201

19. **PPGMR, LLC**
    Contact: John Peiserich
    Phone: 501-603-9000
    Address: 201 East Markham Street, Suite 200, Little Rock, AR 72201

20. **Energy Policy Network***
    Contact: Randy Eminger, Executive Director
    Phone: 806-674-7079
    Email: randyeminger@gmail.com
    Address: 7 Balsham Lane, Bella Vista, AR 72714

21. **Enterprise Products Partners LP***
Contact: W. Randall Fowler, Co, CEO
A.J. Teague, Co, CEO
Michael Hanley, Pipelines and terminals
Phone: 713-381-6500
Address: 1100 Louisiana Street, 10th Floor, Houston, TX 77002-5227

22. **NGL Energy Partners LP***
Contact: Michael Krimbill, CEO
Jayson Fishel, Operations Coordinator
Phone: 918-481-1119
Cell: 765-894-9075
Address: 6120 South Yale Avenue, Suite 805, Tulsa, OK 74136

23. **TARGA Resources***
Contact: Scott Pryor, Logistics and Transportation
Kelley Atkins, Greenville Terminal
Phone: 713-584-1100
Cell: 479-200-1776
Address: 811 Louisiana Street, Suite 2100, Houston, TX 77002

24. **CHS***
Contact: Adam Delawyer, Executive VP CHS Energy
Mark Porth, Senior Account Manager
Phone: 651-355-8508
Cell: 816-812-3331
Address: 5500 Cenex Drive, Inver Grove Heights, MN 55077

25. **Silica Transport Inc.***
Contact: James Knight, President
Phone: 870-346-5811
Address: P.O. Box 9, Guion, AR 72540

26. **Ozark Petroleum***
Contact: Scott Sefton, Operations
Cell: 870-213-6920
Address: 1939 West Main Street, Mountain View, AR 72560

27. **Craft Propane Inc.***
Contact: Rohn Craft, President
Phone: 870-932-4325
Address: 3203 Dan Avenue, Jonesboro, AR 72401

28. **Sungas Inc.***
Contact: Jimmy Reynolds, Owner
Lance Reynolds, Owner
Jim Burcham, Manager
Phone: 501-581-7500
Address: P.O. Box 102, Damascus, AR 72039

29. **Arkansas Propane Gas Association***
Contact: Melissa Moody, Director
Phone: 501-350-1213
Address: P.O. Box 3632, Little Rock, AR 72203

30. **Office of Arkansas Attorney General Leslie Rutledge***
    Contact: Chuck Harder, Deputy Attorney General
    Phone: 501-682-4058
    Address: 323 Center Street, Suite 200, Little Rock, AR 72201

31. **Jackson Walker***
    Contact: Michael J. Nasi, Attorney at Law
    Phone: 512-236-2216
    Address: 100 Congress Avenue, Suite 1100, Austin, TX 78701

32. **Arkansas Forest & Paper Council***
    Contact: Brent Stevenson, Executive Director
    Phone: 501-372-4500
    Cell: 501-519-7260
    Email: brent@brentstevensonassociates.com
    Address: 318 South Pulaski Street, Little Rock, AR 72201

*Proposed additional contacts for testimony.

ENERGY RESOURCES PLANNING TASK FORCE

March 29, 2021 | 3:00 p.m.

TESTIMONY QUESTIONS

PUBLIC SERVICE COMMISSION

1. What energy source could augment natural gas enough to ensure an adequate supply of electricity during a weather condition like Arkansas experienced in February of 2021?
2. Are there any incentives the state could provide to help ensure an adequate supply of electricity?
3. Is there anything the state can do through regulatory requirements or incentives to help with adequate supplies of diesel for back-up generation?
4. Could additional Liquefied Petroleum Gas Peak Shaving help prior to or after the custody transfer/city gate with natural gas end use or electrical generation?
5. What would be your recommendations going forward to help ensure adequate supplies of both natural gas and electricity for the state?
6. With respect to the planned changes in the electric generation capacity mix over the next decade, what steps are being taken to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?
7. Are there reasonably available storage solutions for natural gas or electricity that could be implemented in the state? What are current barriers to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events so as to reduce the cost to value ratio? Are there changes to Arkansas law, Public Service Commission tariffs, or state agency rules that would be needed to be made to implement these strategies? If so, what changes would you suggest?
8. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?
9. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?
10. What regulatory requirement could be changed or done away with that would allow or help ensure adequate supplies of natural gas both for end use and electrical generation?
11. What new regulatory requirement could be put in place that would allow or help ensure adequate supplies of natural gas both for end use and electrical generation?

ELECTRIC UTILITIES

(Entergy, Arkansas Electric Coop, Southwestern Electric, Oklahoma Gas and Electric, Empire District Electric, Arkansas Municipal Power Association)

1. What energy source could augment natural gas enough to ensure an adequate supply of electricity during a weather condition like Arkansas experienced in February of 2021?

2. Are there any incentives the state could provide to help ensure an adequate supply of electricity?

3. Is there anything the state can do through regulatory requirement or incentives to help with adequate supplies of diesel for back-up generation?

4. Could additional Liquefied Petroleum Gas Peak Shaving help with additional electrical generation?

5. What would be your recommendations going forward to help ensure adequate supplies of electricity for the state?

6. With respect to the planned changes in the electric generation capacity mix over the next decade, what steps are being taken to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

7. Are there reasonably available storage solutions for gas or electricity that could be implemented in the state? What are current barriers to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events so as to reduce the cost to value ratio? Are there changes to Arkansas law, Public Service Commission tariffs, or state agency rules that would be needed to be made to implement these strategies? If so, what changes would you suggest?

8. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

9. Are there changes that you would suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g. pump storage or battery) in advance of a forecast extreme weather event? If so, what changes would you recommend? Are there constraints in place from Federal Energy Regulatory Commission or North American Electric Reliability Corporation that would prevent implementation of such changes?

10. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

11. What regulatory requirement could be changed or done away with that would allow or help ensure adequate supplies of natural gas?

12. What new regulatory requirement could be put in place that would allow or help ensure adequate supplies of natural gas?

13. Describe your preparedness and allocation process for critical energy resources during extreme events.

14. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

NATURAL GAS PRODUCERS AND SUPPLIERS

(Center Point Energy, Ark Ok Gas Corp, Black Hills Energy , AIPRO)

1. What improvements could be made to the weatherization of gas wells and other gas infrastructure in Arkansas, Oklahoma, and Texas to prevent a natural gas resource constraint like what was experienced during the February weather event? Should changes be made to Arkansas law or state agency rules to implement these changes for Arkansas's natural gas infrastructure?

2. To what extent can Arkansas coordinate with Texas and Oklahoma to ensure that the region has adequately weatherized natural gas infrastructure?

3. What regulatory requirement could be changed or done away with that would allow or help ensure adequate supplies of natural gas?

4. What new regulatory requirement could be put in place that would allow or help ensure adequate supplies of natural gas?

5. Are there any incentives the state could provide to help ensure an adequate supply of natural gas?

6. Could additional Liquefied Petroleum Gas Peak Shaving help prior to or after the custody transfer/city gate?

7. What would be your recommendations going forward to help ensure adequate supplies of natural gas for the state?

8. Are there reasonably available storage solutions for natural gas that could be implemented in the state? What are current barriers to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events so as to reduce the cost to value ratio? Are there changes to Arkansas law, Public Service Commission tariffs, or state agency rules that would be needed to be made to implement these strategies? If so, what changes would you suggest?

9. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

10. Describe your preparedness and allocation process for critical energy resources during extreme events.

11. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

REGIONAL TRANSMISSION ORGANIZATIONS

(MISO, SPP)

1. What is your role and responsibilities during shortages of critical energy resources?
2. What energy source could augment natural gas enough to ensure an adequate supply of electricity during a weather condition like Arkansas experienced in February of 2021?
3. With respect to the planned changes in the electric generation capacity mix over the next decade, what steps are being taken to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?
4. Are there changes that integrated system operators need to consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g. pump storage or battery) in advance of a forecast extreme weather event? If so, what changes would you recommend? Are there constraints in place from Federal Energy Regulatory Commission or North American Electric Reliability Corporation that would prevent implementation of such changes?
5. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?
6. What regulatory requirement changed or done away with that would allow or help ensure the adequate supply of electricity in the state?
7. What new regulatory requirement could be put in place that would allow or help with the supply of electricity in the state?
8. Describe your preparedness and allocation process for critical energy resources during extreme events.
9. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

LIQUEFIED PETROLEUM GAS

PIPELINE

(Enterprise Products Products Partners LP)

1. What existing regulatory requirement could be changed or done away with that would help strengthen your position within the state?
2. What new regulatory requirement could be put in place to ensure adequate supply during shortages of critical energy resources?
3. Are you aware of any planned additional Liquefied Petroleum Gas pipeline terminals within the state in the near future?
4. Are additional pipeline terminals within the state possible?
5. Are there any incentives the state could provide that would strengthen your position within the state or could help add additional terminals?

6. In order to pull product off your line do you have a minimum barrel requirement?
7. Do you work off of annual purchase for seasonal allocation?
8. What would be the suggested total above ground Liquefied Petroleum Gas storage requirement to adequately serve a terminal?
9. Are there currently any points along your pipeline in Arkansas that would readily lend itself to building a terminal?
10. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?
11. Describe your preparedness and allocation process for critical energy resources during extreme events.
12. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

TERMINALS

(NGL, Targa, CHS)

1. Are there any incentives the state could provide that would strengthen your position within the state?
2. Do you currently have any expansion plans within the state?
3. What would be your recommendations to help secure adequate supplies of Liquefied Petroleum Gas for the end user within the state?
4. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?
5. What existing regulatory requirement could be changed or done away with that would help strengthen your position within the state?
6. What new regulatory requirement could be put in place that would help strengthen your position within the state?
7. Describe your preparedness and allocation process for critical energy resources during extreme events.
8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

TRANSPORTATION

(Silica Transport, Ozark Petroleum)

1. Are there any incentives the state could provide that would strengthen your position within the state?
2. What would be your recommendations to help secure adequate supplies of Liquefied Petroleum Gas for the end user within the state?

3. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?
4. What existing regulatory requirement could be changed or done away with that would help strengthen your position within the state?
5. What new regulatory requirement could be put in place that would help strengthen your position within the state?
6. Describe your preparedness and allocation process for critical energy resources during extreme events.
7. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

DEALER

(Craft Propane, Sungas, APGA)

1. Are there any incentives the state could provide that would strengthen your position within the state?
2. Would increasing storage with in the dealer network help manage an adverse weather event?
3. Would an increase in the number of wholesalers within the state help manage an adverse weather event?
4. Would an increase in the number of pipeline or rail terminals within the state help manage an adverse weather event?
5. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?
6. What existing regulatory requirement could be changed or done away with that would help strengthen your position within the state?
7. What new regulatory requirement could be put in place that would help strengthen your position within the state?
8. Describe your preparedness and allocation process for critical energy resources during extreme events.
9. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

ENERGY USERS

(Arkansas Electric Energy Consumers, Arkansas State Chamber of Commerce, Arkansas Environmental Federation)

1. Do Arkansas business owners whose facilities were asked to curtail operations during the February weather event feel they were treated fairly and given adequate notice? Would you suggest any changes to the prioritization of gas and electricity or communications regarding extreme weather events? If so, what changes would you make?
2. Did the curtailment during the load shedding event damage or reduce the effectiveness of environmental quality control equipment? Are there strategies that could have been implemented to mitigate the impacts of curtailment and the extreme cold on control equipment?
3. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?
4. Describe your preparedness and allocation process for critical energy resources during extreme events.
5. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

ENERGY RESOURCES PLANNING TASK FORCE

Meeting Agenda

May 12, 2021 | 3:30 p.m.

TASK FORCE MEMBERS

Secretary Becky Keogh, Department of Energy & Environment
Secretary Mike Preston, Department of Commerce
Director Lawrence Bengal, Oil and Gas Commission
Director Kevin Pfalser, Liquefied Petroleum Gas Board

ZOOM CALL INFORMATION

Meeting Link:
https://zoom.us/j/98092202656?pwd=bmdOMHhONkRuM3F0SmhNRGNOTzdvUT09

Meeting I.D.: 980 9220 2656

Passcode: 896330

AGENDA ITEMS

3:30 p.m.	• Call meeting to order
3:35 p.m.	• Pre-filed testimony status
3:50 p.m.	• Hearing schedule
4:05 p.m.	• Testimony format discussion
4:30 p.m.	• Adjourn meeting

ENERGY RESOURCES PLANNING TASK FORCE

MINUTES

DETAILS

Date and Time: 5/12/21 | 3:30 pm

Location: Zoom

Subject: Testimony Status and Hearing Schedule

Task Force

Becky Keogh, E&E Secretary, Task Force Chair

Kevin Pfalser, Liquified Petroleum Gas Board Director, Task Force Member

Lawrence Bengal, Oil and Gas Commission Director, Task Force Member

Michael Preston, Commerce Secretary, Task Force Member

Other Attendees

Donnally Davis

Tricia Treece

Shane Khoury

Troy Deal

AGENDA ITEMS

1. Call to Order — Secretary Keogh

Secretary Keogh, as Task Force Chair, called the meeting to order at 3:30 pm

2. Pre-Filed Testimony Status — Task Force Members

Twenty-three entities responded to questionnaires. Some entities requested a time extension for submission of written testimony. Others stated that it might be difficult for them to submit in writing a response representative of all members of their diverse membership and that some of the questions address issues with which their membership may not deal with. Entities also expressed the need to ensure that they do not limit their ability to be responsive to other inquiries.

Task force members agreed to review the written testimony received to date in advance of hearings scheduled for late May/early June

3. Testimony Schedule — Task Force Members

Secretary Keogh introduced a proposed testimony schedule produced by E&E staff for discussion. Task force members discussed availability and suggested revisions to the schedule.

The revised schedule suggested by task force members is as follows:
Thursday, May 27: PSC, AG, RTOs, Energy Users
Tuesday, June 1: Natural Gas Suppliers, Electric Utilities
Wednesday, June 2: Liquefied Petroleum, Miscellaneous, and Follow-up.

The task force also discussed the possibility of setting up a make-up date if entities from which testimony was requested could not make the assigned date.

4. Testimony Format Discussion Task Force Members

Task force members discussed providing 3 – 5 minutes for each entity to introduce their perspective on the event followed by the opportunity for each task force member to ask one question of the entity.

5. Adjournment Secretary Keogh

Secretary Keogh adjourned the meeting at approximately 3:55 pm.

ARKANSAS
ENERGY & ENVIRONMENT

FOR IMMEDIATE RELEASE:
May 26, 2021

Energy Resources Planning Task Force Public Hearing Notice

NORTH LITTLE ROCK—The Energy Resources Planning Task Force will hold its first of three public hearings at 1:30 p.m. on May 27, 2021. All organizations that have been asked to provide testimony have been notified.

The public hearing will be live-streamed on Arkansas PBS at: https://www.myarkansaspbs.org/arcan/home. If you are unable to access the meeting via television or internet, then please contact EEComms@adeq.state.ar.us to obtain instructions for how to listen via telephone.

On March 3, 2021, Governor Hutchinson signed Executive Order 21-05 to establish the Energy Resources Planning Task Force. The Task Force is made up of the Arkansas Department of Energy and Environment, the Oil and Gas Commission, the Liquefied Petroleum Gas Board, and the Department of Commerce.

CONTACT: EE-Press@adeq.state.ar.us

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ENERGY RESOURCES PLANNING TASK FORCE

PUBLIC HEARING AGENDA

THURSDAY, MAY 27, 2021

1:30 p.m.-4:30 p.m.

1:30 p.m.– 3:00 p.m.	**Call Meeting to Order** **Public Hearing Guidelines:** • Task Force Chair will moderate • Testimony will be limited to five minutes • Q&A will be limited to fifteen minutes **Order of Testimony:** 1. Public Service Commission, Chairman Ted Thomas 2. Attorney General Office, Deputy Attorney General Chuck Harder 3. Mid-Continent Independent Systems, Executive Director Daryl Brown and Legal Counsel Randall Bynam 4. Southwest Power Pool, Executive Vice President and General Counsel Paul Suskie
3:00 p.m.	**Recess**
3:15 p.m.– 4:30 p.m.	**Call Meeting to Order** **Public Hearing Guidelines:** • Task Force Chair will moderate • Testimony will be limited to five minutes • Q&A will be limited to fifteen minutes **Order of Testimony:** 1. Arkansas Environmental Federation, Executive Director Ava Roberts 2. Arkansas Electric Energy Consumers, Executive Director Steven Cousins 3. Arkansas Forest and Paper Council, Executive Director Brent Stevenson, Attorney Kelly McQueen, Retired General Manager Domtar Buddy Allen 4. Quattlebaum Law Firm, Managing Member Michael Heister

ENERGY RESOURCES PLANNING TASK FORCE

MINUTES

DETAILS

Date and Time: 5/27/21 | 1:30 pm – 4:30 pm

Location: Department of Energy and Environment (E&E) Headquarters, Live streamed on Arkansas PBS

Subject: Public Hearing

Task Force

Becky Keogh, E&E Secretary, Task Force Chair

Kevin Pfalser, Liquefied Petroleum Gas Board Director, Task Force Member

Lawrence Bengal, Oil and Gas Commission Director, Task Force Member

Steve Sparks, Director, Existing Business Resources, representing Mike Preston, Commerce Secretary

Other Attendees

Mike Ross, Senior Vice President, Southwest Power Pool, Inc.

Trent Minner, Assistant Attorney General, Arkansas Attorney General's Office

Leslie Davis, President, Arkansas Environmental Federation (AEF)

Michael Heister, Attorney, Quattlebaum, Grooms & Tull PLLC

Daryl Brown, Executive Director, External Affairs South Region, Midcontinent Independent System Operator, Inc. (MISO)

Steven Cousins, Executive Director, Arkansas Electric Energy Consumers, Inc. (AEEC) and Arkansas Gas Consumers, Inc. (AGC)

Shawn McMurray, Attorney, representing AEEC and AGC

Randall Bynum, Partner, Dover Dixon Horne PLLC

Madison Wright, Dover Dixon Horne PLLC

Chuck Harder, Arkansas Attorney General's Office

Paul Suskie, Executive Vice President, Policy and General Counsel, Southwest Power Pool, Inc. (SPP)

Christina Baker, Assistant Attorney General, Arkansas Attorney General's Office

Ted Thomas, Chairman of Arkansas Public Service Commission

Caleb Stanton, Legisltavie and Agency Liaison for Energy, Environment and Transportation,Arkansas Governor's Office

Brent Stevenson, Director, Arkansas Forestry and Paper Council (AFPC)

Kelly McQueen, Attorney, representing AFPC

Buddy Allen, AFPC

Ava Roberts, Executive Director, Arkansas

		Environmental Federation
John Bethel, Director of Public Affairs, Entergy Arkansas, Inc.	**Shane Khoury,** E&E	**Donnally Davis,** E&E
Andrea Hopkins, E&E	**Daniel Pilkington,** E&E	**Troy Deal,** E&E
Tricia Treece, E&E	**Beth Thompson,** E&E	**Julie Link,** E&E

AGENDA ITEMS

1. Call to Order **Secretary Keogh**

Secretary Keogh, as Task Force Chair, called the meeting to order at 1:35 pm. Secretary Keogh explained hearing logistics. For each organization, opening testimony was limited to five minutes with up to fifteen minutes for questions and answers from Task Force Members

2. Summary of Chairman Ted Thomas' Testimony **Public Service Commission Chairman**

Chairman Ted Thomas explained that natural gas production was a problem during the February 2021 winter event. It was too cold for some of the natural gas production that the system relies upon. In addition, other generation assets did not meet expected performance levels.

Chairman Thomas provided three suggestions for long-term planning of energy resources:

1) Do not silo the reliability discussion from climate policy discussion. A better political debate of carbon reductions, cost to consumers, and reliability is needed.
2) We need to explore demand response to match intermittent generation with intermittent load. There should be appropriate price signals that incentivize consumers to voluntarily reduce load when needed.
3) Existing generation assets need to perform better when called upon.

Chairman Thomas was asked whether there is a backup fuel of choice if a fuel source is interrupted. Chairman Thomas responded that a fuel source isn't secure if someone wants to ban it. He suggested looking into demand response and market-based policies.

Chairman Thomas was asked whether dispatchable generation, such as the coal plant in Independence County, should remain operational. Chairman Thomas responded that what really matters is the regional resource mix. Even if Arkansas's resource mix is perfect, we would still be blacked out if there is a blackout in the region. We should study whether dispatchable generation should remain, but there are downsides to preserving older resources: the Independence units were some of the units that had difficulty running during the event, they are older and harder to maintain, they are the largest un-scrubbed plants, making them a target for expensive emission control retrofits, and a future carbon policy could make the units even more costly to run.

Chairman Thomas was asked whether there was anything the state could do to independently require fuel usage. Chairman Thomas responded that it was easy to require a fuel to be used, but a violation of federal law to prohibit the fuel from crossing the state line. The problem is a question of cost. If federal policy puts a carbon tax in place and we have mandated use of a high carbon fuel, we are mandating that we have to spend more than we would otherwise have to. There is value in diversity rather than putting all of the eggs in the cheapest basket when there is risk.

Chairman Thomas was asked whether price or politics are driving fuel choice right now. Chairman Thomas responded that it is mostly price. However, he discussed the need to address subsidies. A subsidy is justified to scale up a technology, but not once technology becomes scaled. For wind, the production tax credit is no longer needed. The solar investment credit subsidy is better structured because it reduces the amount of the subsidy as costs go down. Chairman Thomas suggested taking the wind subsidy away and instead subsidizing storage to scale up that technology.

3. Summary of Testimony from Chuck Harder, Deputy Attorney General for Public Protection	**Arkansas Attorney General's Office**

Mr. Harder explained that the Attorney General's Office is looking into what happened in two capacities: as the consumer advocate for Arkansas and as the ratepayer advocate for Arkansas. The Attorney General's Office is investigating operational issues during the event, costs to consumers, and whether there was any price gouging.

Mr. Harder was asked if there were any recommendations that the Task Force should work on to benefit what the Attorney General's Office and Public Service Commission are doing. Mr. Harder suggested looking into how we determine who is shut off first if an energy shortage event happens again, whether there are facilities that are critical to continue to operate to prevent large-scale economic damage, and providing tools to municipal utilities so they have the ability to pay if fuel costs rise due to a shortage.

Mr. Harder was asked if the Attorney General's Office would be investigating price gouging, and if the natural gas supply had not been affected by the weather event. Mr. Harder responded that they perform an investigation whenever the Governor declares an emergency, but the investigation probably would not have been as intense if the freeze offs had not occurred.

4. Summary of Testimony from Daryl Brown, Executive Director, External Affairs South Region	**MISO**

Mr. Brown provided a report to Task Force members that steps through what happened, lessons learned, MISO operations during the event, and important considerations related to the reliability imperative.

Mr. Brown pointed out that this was the most extreme weather event facing the MISO region in the last 30 years. Their approach served the region well in the past, but must be revised to address challenges faced today. There are different risk profiles as more renewable energy enters the system and based on a predicted increase in extreme events.

Mr. Brown provided 5 key takeaways:
1) Generation performance is critical
2) Weatherization can mitigate risk. Standard criteria should be established.
3) Resource adequacy planning needs to change to a seasonal model instead of annual. Currently, they plan around the summer peak. However, there were times during the February 2021 storm when load exceeded the summer peak.
4) Adequate transmission is vital. There was adequate energy produced during the storm, but transmission constraints hindered delivering electricity where it was needed.
5) Improved planner tools are needed for the operations of the future.

Mr. Brown was asked whether gaps in transmission were identified and if Mr. Brown had

recommendations to address them.
Unlike ERCOT- the grid in Arkansas is more interconnected. Power can flow across different footprints in the Eastern Interconnect. MISO's Reliability Imperative Living Document (provided to the Task Force) outlines recommendations for what needs to take place to fill those gaps. MISO does not own the assets so discussions among utilities and regulators in the fifteen states where MISO operates is needed to look at what to build and how to pay for it.

Mr. Brown was asked whether MISO has any influence on fuel type for new plants. Mr. Brown explained that MISO doesn't decide what to build. Their goal is to ensure the lowest cost of generation to meet demand.

Mr. Brown was asked about whether there were any renewable fuels that are not intermittent. Mr. Brown explained that renewable energy sources on the grid are all intermittent. However, there is some work being done to evaluate the use of hydrogen as a renewable energy source.

Mr. Brown was asked about how ad hoc conversations held during the February 2021 event might be formalized. Mr. Brown suggested that they could have quarterly or semi-annual meetings to discuss public-private partnerships. Mr. Brown suggested that the Public Service Commission would be best situated to formalize such an ongoing conversation.

Mr. Brown was asked about the composition of the fuel mix in the MISO footprint. Mr. Brown made Task Force members aware that there is a MISO app that shows the fuel mix at any given time. Mr. Brown explained that the ability to leverage energy from across the MISO region and across the Eastern Interconnect is the key to being successful at assuring reliability.

Mr. Brown also mentioned a report that MISO put together on a forward-looking report on electrification. The preliminary findings from this report were introduced to the Task Force and provided to the court reporter.

5. Summary of Testimony from Paul Suskie, Executive Vice President of Regulatory Policy and General Counsel SPP

Mr. Suskie explained that the February 2021 event was the first in SPP's 80 year history where they had a load shedding event of this magnitude region wide. Mr. Suskie pointed out that although this was a first for SPP, it has occurred multiple times across the country. SPP is presenting a comprehensive report on lessons learned from the event to its Board of Directors in July. Mr. Suskie praised Ted Thomas for his expertise and assistance on the Regional State Committee. Mr. Suskie explained that SPP is a transmission planner and a market operator that balances load with generation on the system. Too much or too little generation can lead to blackouts. Mr. Suskie described three load shedding events in SPP during the February 2021 event and explained that cascading blackouts did not occur because they were able to pull energy across the entire eastern interconnect. Mr. Suskie explained that the cost of natural gas directly impacts the market because in most cases cheap gas is setting the market value.

Mr. Suskie was asked whether there were any lessons learned. Mr. Suskie explained that they valued their coordination with MISO on planning for the grid of the future, seams projects, and other maters. MISO provided a large amount of power to the SPP footprint during the event. Many of the lessons learned from a 2018 event were implemented during the February 2021 event.

Mr. Suskie was asked what the source of the power imported into SPP was during the event. Mr. Suskie explained that you cannot know the fuel source when you are pulling in energy at that volume.

Mr. Suskie was asked how the changing fuel mix will affect the ability to respond to events in the future absent a natural gas disruption. Mr. Suskie explained that coal and natural gas underperformed, based on what those resources are credited for reliability purposes. Mr. Suskie explained that you dispatch the cheapest energy first and that wind bids in negative prices on the market. In a deregulated system like ERCOT without a capacity market, the cheapest generation gets built. Vertically integrated systems, such as the SPP state systems, provide more protection.

Recess 2:45 pm – 3:15 pm

6. Summary of Testimony from Ava Roberts, Executive Director AEF

Ms. Roberts explained that the AEF members who responded to questions submitted by the Task Force indicated that earlier and more detailed information is needed before curtailment. Members who responded indicated that curtailment did not reduce the effectiveness of environmental control equipment.

Ms. Roberts was asked about how the notification process should change, whether any members have the ability to generate their own electricity if there is a load shed, and whether there was a differentiation in notices from electricity and natural gas. Ms. Roberts responded by stating that AEF's members did not go into detail on those issues, but that she is happy to follow-up with them to get answers to the questions posed by task members.

7. Summary of Testimony from Steve Cousins, Executive Director and Shawn McMurray, Outside Counsel AEEC and AGC

Mr. Cousins explained that the February 2021 winter event was a tale of two cities. He is not aware of a single group in his membership that had electricity interrupted who were not on an interruptible contract. On the natural gas side, most members with equipment that could be damaged by cold weather weren't aware of the procedure to an file plant protection affidavits and some didn't know they were going to be curtailed until someone showed up to shut off the gas.

Mr. Cousins also explained that many customers were not aware of the spot price of gas that they were purchasing. Mr. Cousins suggested improvement in real-time price signaling would allow customers to make a business decision to self-curtail when prices get too high.

Mr. Cousins was asked whether there was a need to have a required notification process from a regulatory standpoint or best practice. Mr. Cousins emphasized that the notification system on the electric side is working and that the notification requirements are spelled out in the tariff. Although the ability to obtain a special needs waiver is in the gas tariff, not many people are aware of it. Nothing in the tariff talks about notifications and advanced warning.

Mr. Cousins was asked about possible solutions to provide more transparency of real-time costs for gas. Mr. Cousins explained that he wasn't sure about a regulatory basis for solving the real-time cost transparency issue. However, there could be requirements spelled out in private contracts. Mr. Cousins suggested that suppliers could provide a notice when the Henry Hub spot price for gas takes a major jump in cost. Mr. Cousins also explained that current firm and interruptible parts of a gas contract are primarily set up for addressing issues with pipeline capacity, not lack of gas in the pipeline.

Mr. Cousins was asked about who a special needs waiver is filed with. Mr. Cousins explained that it is filed with the interstate pipeline company.

Mr. Cousins was asked about who was affected by curtailments in his membership. Mr. Cousins indicated that he doesn't have a feel on how the decisions on who got gas and who didn't were made. Mr. Cousins indicated that on the propane side, the biggest single problem was truck traffic being hampered. This made it difficult to re-supply.

8. **Summary of Testimony from Kelly McQueen, Buddy Allan, and Brent Stevenson, Director** — **AFPC**

Ms. McQueen emphasized the large footprint of AFPC members in Arkansas. Ms. McQueen recommended that there should be quicker communication and appropriate price signals for natural gas, ensuring that federal and state rules regarding gas infrastructure do not conflict, and education about affidavits. Ms. McQueen suggested looking at what can be done to enhance interruptible tariff design to bring appropriate value to interruptible customers.

Ms. McQueen was asked whether there were any conflicting rules with respect to DEQ. Ms. McQueen stated that it was more of an issue with utility rules.

Ms. McQueen was asked how many of AFPC members experienced a curtailment and whether it was a natural gas curtailment, electricity curtailment, or both. Ms. McQueen explained that all of their members experienced curtailment. It was a combination of gas and electric depending on the particular circumstance. Ms. McQueen explained that there were a number of members who were curtailed for gas. Most had affidavits in place, but some did not. Members lost tens of millions of dollars due to the need for extra man hours, equipment downtime, increased prices, and damaged equipment.

Ms. McQueen suggested that members didn't have the opportunity to make business decisions based on the exaggerated costs. They operated and then were billed. Ms. McQueen suggested that this is a contractual issue and that better price signaling would help members to decide when to self-curtail rather than pay exorbitant prices. Ms. McQueen suggested that the supplier should be responsible for that communication.

Ms. McQueen was asked whether the cost and damagers were more due to electric or gas. She indicated that gas curtailment is easier to deal with when you have notice. Loss of electric is sudden.

Ms. McQueen was asked whether AFPC was helping to educate members. Ms. McQueen indicated that AFPC is well positioned to help.

9. **Summary of Testimony from Michael Heister, Attorney** — **Quattlebaum, Grooms, & Tull PLLC**

Mr. Heister praised state agency staff for being available to pick up the phone and work with him during the event. Mr. Heister explained that clients got short notice that they were going to be shut off because they don't have a special needs affidavit. Putting one together was a quick turnaround and there was no assurance that once on file, the natural gas would be there.

Mr. Heister also pointed out that there were water disruptions due to loss of electricity at water pumps. Mr. Heister urged the Task Force to step back and think about big picture issues. Mr. Heister suggested enhancing education about special needs affidavits. Mr. Heister suggested the Task Force should consolidate its findings in a place that can be used to advise clients. Mr. Heister also suggested a trigger for notice if the price of gas increases by a certain percentage. He also suggested that there be a voluntary stress test on the system.

Mr. Heister was asked what resources would fund the voluntary stress test and what it should look like. Mr. Heister suggested soliciting feedback on the problems they saw and what kind of equipment is likely to fail. Consultants could create advanced guidance and checklists to advise companies of weaknesses in their internal infrastructure.

Mr. Heister was asked about stress testing for smaller organizations. Mr. Heister suggested that the Task Force could compile a tool kit for assessing energy vulnerabilities rather than having consultants create them from scratch for each company.

10. Closing Remarks **Secretary Keogh**

Secretary Keogh concluded the hearing at 4:15 pm.

ENERGY RESOURCES PLANNING TASK FORCE

PUBLIC HEARING

THURSDAY, MAY 27, 2021 AT 1:30 P.M.

TASK FORCE MEMBERS PRESENT:

Ms. Becky Keogh

Mr. Kevin Pfalser

Mr. Lawrence Bengal

Mr. Steve Sparks (on behalf of Mike Preston)

TIFFANIE N. HARRISON, CCR
BUSHMAN COURT REPORTING
LITTLE ROCK, ARKANSAS 72203
(501) 372-5115
harrisonreporting@outlook.co

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PROCEEDINGS

May 27, 2021

MS. KEOGH: Today is May 27, 2021. Appreciate you all joining us here at the Arkansas Department of Energy and Environment Headquarters. We come here today to hear testimony for the Energy Resources Planning Task Force at the commission of Governor Asa Hutchinson. I'm Becky Keogh. I'm Secretary of the Arkansas Department of Energy Environment and I have the pleasure of serving this task force, along with Secretary of Commerce, Mike Preston, Director of the Oil and Gas Commission, Larry Bengal, and Kevin Pfalser, who is the Director of the Liquefied Petroleum Gas Board. Today, representing Secretary Preston, we're happy to welcome, Steve Sparks, Director of AEDC, Central Business Resources Division. So we're happy to have Steve join us on behalf of Mike Preston, who is out of state.

On March 3rd of 2021, Governor Asa Hutchinson signed Executive Order 2105, that established the Energy Resources Planning Task Force. Hopefully, you've had a chance to see this Executive Order, which lays out the purpose and the goals of the task force. The purpose of this hearing today, as the process, is to gather information, specifically today from testimony, in order to better prepare our states energy infrastructure, in the event of another statewide emergency, as we experienced in February of this year.

As chair of the task force, I will be calling names of organizations that have offered and are willing to provide testimony today. So those of you, I appreciate you being here today. Thank you so much. When I call out the organization that you represent, please come to the podium, and state your name, and title, and the organization for the record, because we're recording this for future review.

We are asking each speaker to -- or each actual organization, to limit testimony to five minutes. Some of you may have multiple speakers, so we ask that you share that time, if possible, as far as any kind of statement you want to make, opening statement today, in your testimony. After you complete your presentation, then I will open the floor to our task force members to ask questions of each of the representatives. We've allotted about 15 minutes, to try to stay on track. We're going to hear from a large number of parties, some today, and we look forward to being able to ask you some specific questions, that might help us better develop a report, that's due to the Governor in the upcoming months.

So Andrea Hopkins is here, sitting at the front desk, to be the regulator of time for this process. She will keep time, and I know that she will respectfully declare when your time is getting close, and hopefully you'll respect her request to stay within those time limits, just for the benefit of all the other speakers, and respectful of those watching and joining us. We are live streaming this hearing, so for the benefit of the public and others.

We do have two additional days of hearings scheduled. If you want information about those, you're welcome to get them while you're here for those that speak today, and we'll live stream those hearings when they occur next week.

I think I will go back to my original

agenda, and I'm going to open the testimony by asking the Public Service Commission to come forward as our first speaker. Chairman Thomas, if you will just provide your name, title, and the organization after -- in a moment, when we get started. I've just got to mention, that following Chairman Thomas -- we appreciate you being here Chairman Thomas today. It's a privilege having you here today. The Attorney General's Office, will -- we've asked them (indiscernible) Attorney General's Office following Chairman Thomas and the questions that we have for him.

So with that, I will now turn the mic over to you, Chairman Thomas, to begin the process. Again, we're asking for a limit of five minutes in an opening statement and then we'll -- I'll ask the task force members if they have any questions of you. Thank you so much.

MR. THOMAS: Thank you, Secretary Keogh, members of the task force. I'm Ted Thomas. I'm Chairman of the Public Service Commission. I'd first like to note, I speak for myself; not my colleagues. These issues are when you're applying someone with stuff that we do, they have formal hearings. It often puts me in an awkward spot, participating in public discussion while not directly prejudging issues, so that's a line I typically try to walk, but I also like to participate in full discussion, because that's how we (indiscernible).

When one looks at the events that happened in February, the good news is we nicked the wall. If you want to see what crashing into the wall looks like, you can look further south in Texas. They crashed into the wall. We met the wall. Folks in this business, the engineers that built the system (indiscernible) and it happened here, so it's a concern, but we nicked the wall; we didn't slam into it.

Why did that happen? Again, this is preliminary. I brought three things that I'll hand out. These are two charts that basically show the same thing. The problem is a natural gas reduction. If you look at this chart, you can probably see it from there, there's a huge grid dip that recovers and it was too cold for some of our natural gas reduction that we count on. That's what happened, more than anything else.

Now, when we have something like this any incremental factor could be considered (indiscernible) so important to what we expect. The problem is when you have a deal like this, you get into what I call the stupid (indiscernible) awards, which I regard as part of the problem, because instead of the policy response, what we often get is the public relations corporate response. So the gas folks have correctly points out, that they were serving more load than anything else, but the problem is, they're making the wrong message. The real message they should be making in my view isn't that, you know, it wasn't us. It was this is a world without natural gas, because this debate is inevitably tied to the climate debate, because that which we do to protect ourselves, with cost increases related to the climate debate intermittence causes problems, potentially at eye levels of deployment, when you look at reliability issues.

So we have two related policies that cross. What we need is not corporate public relations.

What we need is policy debate. We don't have the policy debate. Yesterday Politico did an online news site. That it was a bad day for big oil, because they lost a couple of shareholder votes, and lost a case in Europe, which basically a court imposed carbon reduction. The word consumer hardly appears in that article.

The corporate folks assured us that they are committed to carbon reduction. The special interests, you know, counted their victory. Nobody mentioned the consumer, and here we have to (indiscernible) consumer on costs, and when you debate the climate issue the way it's been debated, you're not protecting the consumer and if you use liability issues as a reason not to (indiscernible) climate stuff, you're not protecting the consumer.

The second big question, this is what happened, is what can we do about it. That's a jurisdictional issue. Here's another hand out. This came out from a MISO slide show. This will be -- one thing I would point out, this is really a division between one of RPOs regional (indiscernible) and what the state does. And you look at the circle. You know, we have a data head problem. There's nothing that we can do about it. The RPOs are inconsistent. That's pretty much all the true until you get to five and ten year deal. This is on the MISO side. (Indiscernible) the organization of MISO states, which are the regulators from all the states and we do a survey of what's out there, and so when we're figuring out what our generation mix should be, we know what the other states are doing and MISO knows what all the states are doing. So that's when five years out, when the authority begins to melt some and the court (indiscernible) is long term planning.

So we need to think about the resource mix over the long term, because the RPOs run the system on short term. They run what we bring to the table. We decide what we bring to the table. But in the business where you want assets to last 40 or 50 years, there's a huge (indiscernible) time and this is why political debating matters. This is so important. Because if we make a 40 year commitment, we're betting that the politics won't change on us.

Because if the politics changes in the day of natural gas and we bought a gas plan, guess what? We still get to pay for it, even though we don't use it. That's the situation we want to avoid. That's why the politics of the climate debate is so intertwined. You have to win the political fight to protect the value of the resource, because if you lose that, you've made a 40-year commitment, your consumers are going to be paying something for 40 years that they don't use.

So that's my initial presentation. This is division of authority, who does what. The State has long term authority over the resource mix, RPO climate day to day. What happened in January -- or February, I mean, gas reduction. That's why it came back so fast. Three weeks after, we didn't even know it happened, looking in the system for a 24 hour period. So I'll be glad to answer any questions. I'm sure you all have questions. I look forward to hearing your questions and presentations of the other speakers.

MS. KEOGH: Thank you, Chairman Thomas. I'm going to turn this over to each of our task force members to ask questions. And thank you also for providing some pretrial testimony which we have now before us. I know the pretrial testimony that you submitted, you talk about what you do today, liability of the system, and the effect of the policy issues on fuel choice and fuel supplies. I guess, is there any recommendations that you have that we would want to incorporate in our report regarding how we prepare the State to address this -- this 24-hour period, so to speak, as you talk about, when we had the emergency event, if our (indiscernible) is diverse now, how would we create -- is there any recommendations about what our backup fuel choice would be for our citizens across the state, should our fuel sources be interrupted again?

MR. THOMAS: To me one of things -- well, first of all, you can't separate these debates because they are political. Can't separate this from the climate, because your fuel sources and secure (indiscernible), because you get your butt kicked in every election where this matters, which is a risk of things happening.

Second, if you have a problem with intermittent load, or intermittent generation, one of the things you can do is have what we call the man response, which makes load intermittent response to that, and to me from a policy perspective, that's a very important thing, having some degree of flexibility with the load, were you basically get paid to reduce your load, so you're taking a volunteer who gets paid for it (indiscernible) reduce load is them, and if you have a price that sets when people do that, to me that is a market based policy, they can compete with other new technologies.

Third, in MISO, while we're looking at it, I just want to point out about all of this stuff and I hope that when you looked at the reports you saw the technical complexity and the detail, and rigor that goes into that. MISO issued a report yesterday, and one of their recommendations is the existing units that we have, have got to run at a higher level of performance. There were units that didn't run. There were units that tripped off, and because they tripped off, we had to buy natural gas and the supply crunch; it was very expensive. One of the things we need to do is make absolutely sure that the unit's rate payers are paying for, when you get the (indiscernible) determine on when you need them, and it might be under adverse weather conditions that they in fact turn on. That would probably be three main innovations. First, come put this in a silo. Second, we'd explore intermittent load if we have an intermittent generation problem, and third, stuff that we haven't been granted, we ask (indiscernible.)

MS. KEOGH: All right. Thank you. And I'll ask Director Pfalser, do you have any questions for Chairman Thomas?

MR. PFALSER: Yes. And Commissioner Thomas, I was able to view your testimony that you gave before the legislature sometime back.

MR. THOMAS: Yes.

MR. PFALSER: And I appreciate your candor. In reading through the material that you provided, I don't know why we don't just let you decide what we need to do. It seems like it makes a lot of sense. I appreciate your perspective. In the testimony that you provided, in the written testimony, on page 9, we asked the question: Over the next decade what steps will ensure that a mix could provide the sufficient generation? And there were three things that you shared with us. Existing base load, this generation should remain in operation, on reserve. And I think you were referring maybe like a hill fire plant, might be in Independence County, something like that, that might be planned for (indiscernible) to maintain that.

MR. THOMAS: Well, we should say that, now, that's a cost factor. And another important thing with all of this, our state is not walled off. Our state is part of the eastern (indiscernible) connectors. Basically, everything west of the continental divide and it's all interconnected. The resource mix that really matters is the regional resource mix. If the regional resource mix is wrong and there's a regional blackout, we will be blacked out, even if our resource mix is perfect. So we have to work within -- and it's not just other people that's citing it. We've worked with those people. We're stakeholder in their process. We followed and studied and had great relationships in my view, but the (indiscernible) and MISO. We have to remember it's a regional thing. We should say that, but there's also down sides to that.

A few down sides I can think of, one, these were among the units that had difficulty running it, which means we pick the insurance premium but when it was claim time, they were off, and that was a $150 million bank of the envelope guess. These are older plants that cost a lot. There is also a settlement that would have financial consequences, but to me the issue is what's next after them, and that's the decision that is in the four or five years off time frame.

But I don't want it to be seen as (indiscernible) to keeping those. If there is value there, we want to extract it. Another problem is they're the largest unscrubbed coal plants in the nation. So they're graduates, you can use them to work for Joe Biden's EPA, and you click admissions, and sort by most, you get two Arkansas plants. There was target on our back.

MR. PFALSER: So could those be retrofitted, or is --

MR. THOMAS: Well, the retrofit, one is almost $2 million. Now, I've heard that that estimate was wrong. It will be a rigorous process before we went and did that. But if they put tax on carbon, if they ban coal, that's why the political debate is so important. That will determine what options we have, and you have to continue to win, for 50 years, remaining in debt, and the reason why (indiscernible) awards so the people that are losing the fuel wars, I'm going to bet on them, we need (indiscernible) for 40 years, when they watch the last ten, they just get fresh everyday, including yesterday.

MR. PFALSER: The second thing that you pointed out, was to provide a regulatory record for the RPO's, that for -- I guess, the state next generation, to consider Arkansans first, in extreme situations.

MR. THOMAS: Now, I think we might have -- I'm not sure we're talking on the same --

MR. PFALSER: I might have somebody else's material?

MR. THOMAS: Yes. My recommendations are on page 9. The first one is don't be in (indiscernible) with respect to the policy issues. I think we should maintain vigorous participation in the RPO stakeholder process. But there is a little bit of difference there, between that and the mandate to the RPO.

MS. KEOGH: Director Pfalser, I'm going to move over to Director Bengal, for a moment, if he wanted -- we'll circle back to you, in case there's a follow-up question you have. Director Bengal, did you have questions for Chairman Thomas?

MR. BENGAL: Just briefly. Chairman Thomas, I appreciate your recommendations and comments, because sometimes it's hard to say those things. I really do appreciate that. It's good to hear the truth. On your chart for total (indiscernible), that's the U.S. (indiscernible)?

MR. THOMAS: Yes. I think one of these is Texas only. One report, came from the National Gas Association, so I think it's total, then the other chart, came from the Southwest Power Pool Independent Market Monitor, and I think that's limited to Texas, but you can see the same thing. It was an extreme short lived deal, and the future prices never really went up that much.

MR. BENGAL: My question is, you know, Arkansas originally was a gas importer. We quickly went above what we could use; however the location of that Shell, was located within the pipeline system. On the eastern part of the state most of that gas leaves Arkansas, and most of the gas that we use, unfortunately comes from states that are mostly impacted by this event.

MR. THOMAS: Yes.

MR. BENGAL: When you look at reliability, and usage, is there anything that the state independently can do, to require fuel usage? I know states are requiring not to use, but how to put power of the state to require a fuel be used.

MR. THOMAS: We could do that. It's easy to require that a fuel be used. It's probably illegal, to prohibit that fuel from crossing state lines. The problem is that it's a question of cost. If the feds put on a cost prohibitive carbon tax, and we mandated that, and we're mandating that we spend more than we have to -- which if it's a large (indiscernible) number, the value -- and we recognize the value in diversity. You don't want to put all your eggs in the basket, that's cheapest, when the second cheapest, has uncorrelated risks.

It's all a degree of price, and the RPOs run a market when the cheapest stuff runs next from anywhere in the region. That's part of what's causing our problem. We use the cheap one and running, even when it's not subsidized and it lowers the market price, for everything.

MR. BENGAL: At this point in time, do you think that price or politics is driving fuel choices?

MR. THOMAS: I think it's mostly price with a lot of politics. To me, a subsidy is justified, to scale something up, but once it becomes scaled, it's not justified. When you look at the price, we need to compete unsubsidized, because it's scaleable. To be continued the subsidy the way they have it, doesn't make any sense, because it's already scaled. I didn't bring my price chart, as I normally bring. In fact I discussed them at the joint interview meeting. You can see the prices go like this, and there's a great public benefit, when you take a price that starts high, and then comes down. It happened with personal computers. It happens with every technology, so to me, a little subsidy to get the price coming down, and once it comes down, take the subsidy off. But the subsidy you made gets lost, by the people who are opposed to subsidies every single time, and the wind subsidies, can be problematic. With solar, there's an investment credit subsidy, so when the price comes down by half, the value of the subsidy is reduced by half. With the wind, you have a reduction. The more you produce the more you get. It's nuts. We should take it off of that, and we should put it on storage to make storage come down like that, but that's not gonna happen. People who want that to happen, uses the debate every single time. That's why the political debate might be of some importance, to rationalize these issues.

MS. KEOGH: Thank you Chairman Thomas for preparing for us, and (indiscernible) and your candor and your honesty. But I always appreciate that you bring a lot of good information to the table, and help us in making better choices, so thank you again for being here today. We appreciate your follow-up.

At this point, I'm going to ask the AG's office, to come forward and identify your -- spell thy name and title.

MR. HARDER: Thank you Secretary Keogh. Secretary Keogh and members of the task force, my name is Chuck Harder. I'm a Deputy Attorney General with the Office of Arkansas Attorney General, Leslie Rutledge. By way of background, before joining the Attorney General's Office, I spent 25 years in leadership roles at Centerpoint Energy, in areas of the legal regulatory governmental affairs area. Before joining the Attorney General's Office, I was the Vice President of Regulatory Governmental Affairs and Source Gas, which is now Black Hills.

I'm not going to repeat a lot of what's in my testimony that's been provided. I do want to give some observations and talk about the role of the Attorney General's initial observations that we have. The Attorney General's role in looking at what happened in February is two fold.

One, we're the consumer advocate of Arkansas. We enforce consumer protection laws in the state of Arkansas. And there are some aspects of what happened from an economic standpoint in February, where consumer protection laws of Arkansas may have been breached. In particular, the price gauging laws that went into effect when the Governor declared a state of emergency on February the 10th. That state of emergency lasted until March the 12th.

The second aspect is the Attorney General is the rent payer advocate for Arkansas, so we represent the individual rent payers through the Arkansas Public Service Commission. We're going to look at what I think needs to be looked at. One, do we have (indiscernible) issues. We did dodge a bullet. We didn't face the same problems that Texas faced, but there's some serious operational issues that need to be looked at. We need to do the analysis and look into why power went out for some utilities, the rolling blackouts or force outages. We need to see why Pea Ridge was lost. The town of Pea Ridge was lost for a period of time. We need to understand why companies were forced to go under their curtailment plans.

So natural gas is our additional focus, and when they Interstate Pipelines and Pipelines say that you need to reduce your consumption in a city gate, or the amount of gas you're taking into the city gate, the utility puts into effect its order of curtailment. It shops off the interruptable customers first, who know they're going to be interrupted. Then they start to work their way down through business customers, and ultimately residentials.

One of the issues that we see, and have seen early on, the focus of that has been around human needs. What happens to people? Greater consideration needs to be given to critical business facilities. In particular, in the agriculture industry. You know, there were certain facilites in the poultry industry that had they been forced to cut off their natural gas, could've created problems for the whole industry. And that's the issue that we're looking at, that needs to be looked at, and maybe something the task force considers going forward.

From an economic perspective, which that's another aspect that we're looking at, we're looking at that are going to be active with the proceeding before the Public Utility Commission, we're going to ask the utilities what did you do to plan for the event? Did you have sufficient pipeline capacity and storage capacity on your contract? Did your gas supply contracts? How did you contract for gas supplies? Did you factor in the fact that at any critical event like this, there are going to be freeze-offs? Not to the extent of what we saw, but there are always freeze-offs, in incidents like this. And then how did you perform, when it looked like you were -- didn't have enough to -- maybe enough capacity or supplies throughout the event? Did you act in a timely manner, and if not, was there a cost to the consumer because of that?

We're also looking at the price gauging aspects of it. Price gauging effectively takes away market based pricing when the Governor compares a state of emergency. The pricing becomes cost based. So merchants are allowed to charge consumers the cost -- their cost, plus a reasonable markup, plus 10 percent. The utilities are just flowing through what they paid. So if we're looking at who was supplying them, were they paid -- were they reflecting cost increases in what they charge to the natural gas utilities? And we're working our way up the supply chain, to find which market participate increased their prices not becuase of increased cost, but because of shortages in the market place, and taking advantage of that. That's where the price gauging focus will be.

One thing that we've looked -- that we've discovered in applying the price gauging loss during COVID, is often times that price gauging investigation turns into an anti-trust and market manipulation investigation. And in that regard, we are coordinating with Attorney Generals in the region. This was a regional event. This is not something that happened in

Florida. This is not something that really happened in Mississippi. It happened in (indiscernible). And so we're working with them in that regard.

I'll close out with talking about two issues I think the task force needs to consider, too. One, how do municipal utilities deal with situations like this? Investor owned utilities have some financial tools available to them, and the legislature created securitization as a tool available to them, to be able to pay these bills and not be in financial distress. We need to make sure municipal utilities have those financial tools, because they face the same problems, and they probably didn't have the same flexibility as investor owned utilities.

And the other thing is affordability for residential rate payers. And in those that are going to have a difficult time paying their bills. Sadly, the Commission put into effect a moratorium on disconnects, based on COVID and COVID -- the COVID moratorium has passed, and now residential consumers are subjected to be disconnected for non-payment of their bills.

We need to have -- make sure we have financial assistance programs in place to help those people, should things like this happen. With that, I'll stop my remarks and respond to any questions that you may have.

MS. KEOGH: Well, thank you, and appreciate your presence here and your information. We appreciate the written testimony that we did receive and the clarification of your investigation. That helps make sure we don't repeat the same process that -- quite different purposes, I believe in the investigation, as the Governer is looking more at this as an after action of finding a few lessons learned and a way to improve public service to our citizens. So we appreciate that.

Is there any one recommendation that you would make that -- you just made several, but is there something that as you walk away from this, you really want this task force to focus on the benefit, the work that the AG is doing, as well as the Public Service Commission is doing regarding this event?

MR. HARDER: I think -- the two things I think, of the things I discussed that are probably most important. One is if this event happens again, how are we going to go about determining who to shut off firs, and do we have critical business facilities that need to be on? And I'm focused most on the natural gas. If the power goes out, there's general always the ability to have a backup supply. Hospitals do this all the time. They have a way to generate ground electricity should the power out. So I'm mostly focused on natural gas.

The other piece, too, is just the municipal utilities and their ability to -- you know, there are some that had rainy day funds, or other funds set aside to pay the bills, but there were a lot to do. And so making sure that municipal utilities have tools readily available to them, you know, so their not straggling and trying to figure out how they might pay this bill. I can't put, you know, a $5,000 March natural gas bill on a consumer in, you know, wherever, Arkansas. They need the tools.

Those are two things that I think either are very critical from our perspective. The rest of them in turn -- the rest of it is all a who did what and who needs to pay for what, you know, and how do we go about getting the money back to the consumers, because there were over-charges? But going forward, I think those two are critical issues that need to be studied.

MS. KEOGH: Yeah. And I appreciate that. I'll turn this over -- I'll probably go in reverse order with the members of the task force in asking these questions to you, but I will (indiscernible). Our next speaker will be MISO, in case you want to prepare. I meant to give you that warning, as we brought the Attorney General's Office up.

Do you have a question?

MR. SPARKS: I'm good. Thank you.

MS. KEOGH: Then, I'll turn to Director Bengal.

MR. BENGAL: In the interest of time, I think written testimony provides it for me.

MS. KEOGH: Anything from -- Director Pfalser, do you have a question?

MR. PFALSER: I just had one question. If the natural gas supply had not been effected by the freeze-offs back in Oklahoma and Texas, do you believe that the AG's office would be involved in the price gauging investigation and so forth?

MR. HARDER: When the Governor declares a state of emergency, we're going to look at prices. I think the big driver -- our focus is that -- actually heard that from Chairman Thomas. I think you going to hear from a lot of people today. That was the big driver. So had freeze-offs been what they typically are in winter events, it does happen. Things above ground freeze. Things below ground freeze. Probably not as an intensive an investigation but we would've looked at the rates, but natural gas was the cause, I think of all these cost increases.

MS. KEOGH: All right. And all the information. We look forward to working in corroboration with your office.

MR. HARDER: We do, too. Thank you.

MS. KEOGH: The next speaker we would like to hear from is Mid-Continent Indpendent Systems, and I will note that Southwest Power Pool, we'll be asking you to come forward next. You'll be on standby, but if you would please state your name, title, and organization and we look forward to your statements today. Thank you for being here.

MR. BROWN: Thanks for being here. And I applaud the Governor in this task force and being Proactive in terms of thinking of next steps to avoid some of the issues we had this time. My name is Daryl Brown. On the executive director for MISO to south region's external affairs. I've only been at MISO for about a year. So prior to MISO I worked at Southern Company, GE, and Hitachi. So I have a lot of experience with fortunate, or unfortunate, provided by major events such as this storm.

What I wanted to point to first -- she's going to hand you out a document. This actually just came out yetterday, and you'll see that it's a February arctic event. It basically steps you through everything that happened in terms of the event details, the lessons learned, and then something that is very important to some of things that Chairman Thomas was mentioning in terms of the liability. That's what we call our reliability imparative. You'll see us having after that. That's the light paper that was written some time ago. And then you'll also see our MISO opps procedures. A lot of things that were taking place were questions when it came to us calling a low shed. This steps you through and this will be supplied to our market participants, or vendors, as well as our regulators as the events are taking place. So that's what's contained in here.

There's also some lesson learned. I think they begin on page 25 that you'll find very handy on this topic. This is a summary of lessons learned from that. So with that, you know, Chairman Thomas covered the weather, so I won't remind you of the things that happened, but one thing I will point out though is -- is that it was the most extreme weather event in the last 30 years. So this wasn't a normal situation.

(Indiscernible) overall event was successful for us, in terms of facing extreme conditions. It is also highlighted on impact, that they increase in extreme weather events that was changing the resource (indiscernible) operators ability to maintain their liability. That points back to the liability carrier.

So we published this report, which you have here, just yesterday and it gives, like I said, an account of the details and lessons learned, and the implications of the liability carrier. The approach that served the reason well, I think, in the past, must be adapted to address the liability challenges that we face today. We're preparing, the region for a feature with a different risk profile, as more and more renewal (indiscernible) takes place. And we are thinking that there will continue to be increased extreme weather events.

The reliability imparative addresses the enhancements needed for planning, markets, operations, as well as the systems changes that's needed. These changes that are necessary to tackle how well maintained reliability has MISO reached (indiscernible) takes place.

The lessons learned are five kind of key take-aways as you'll see in there. One is generation performance. The generation performance is always critical when we need sufficient generation, as Chairman Thomas pointed out, to be available at the right times to meet the demand. Winterization to protect generation fuel supplies or extreme weather conditions in mitigating the risk, MISO and its members must assess and establish service area criteria. To date, there's really not standard, when we talk about that from (indiscernible) perspective. We do surveys, but those surveys are more suggestions and thus for piling information in terms of best practices and sharing (indiscernible), but there's not a standard in terms of weatherization.

The next one is resource advocacy planning that needs to be refined. Changing from an annual to a seasonal resource advocacy construct without addressing increasing frequency if heat remains throughout the year. We used to just simply look at a summer peak event, but that's changed. During this winter event, we actually approached in some cases as high as certain periods exceeding the peak event that you would see in the summer. Sometimes it was really close to all time peak.

The next one is transmission. Transmission is vital to moving electricity from where it's generated to where it's needed most. Adequate electricity was available across the MISO region, during our transmission constraints. I heeded the ability to move in to each of the specific areas where it was mostly improved in a regional coordination interconnection, along with (indiscernible) will bring significant benefits to facility the reliability and (indiscernible).

The fourth thing is operations of the future. Our operators that are in the control room are very seasoned veterans. They have great tools, but as, you know, more renewables enter the mix, in terms of buildings, they're going to have to improve those tools and improventional vitals operations. The relevant details will be critical.

Last it's the reliability. And I've counted many years of forward looking planning and decisions. I want all of our stakeholders is what's taken place in the (indiscernible). That will conclude my opening remarks and I'm prepared to answer any questions that you have.

MS. KEOGH: Again, thank you for this, and thank you for this appropriately typed report. We appreciate that. We appreciate it being hot off the press and look forward to reading the recommendations as well as your lessons learned. I guess the question that comes to mind, I've had (indiscernible) through your testimony you've provided a significant and limited amount of information and it helps to educate us all. You mentioned the transmission aspect of it, that's kind of what intrigued me, and some others that perhaps a prior testimony talked about, good potential gap, as we are started by two regional transmission authorities, (indiscernible). Have you identified a similar gap that some people reference and is your recommendation to addressed that in a different fashion going forward, or is -- I guess I could just appreciate (indiscernible) and maybe I like the same thing of Southwest Power Pool, if there is something that can be done. As I understand it, it was quite a bit of energy, and effort to make sure fuel was brought across to those that had needs during the respondent event, outside of the norm, and I appreciate what they did in that respect. I just want you to speak to that reference gap that I've heard of.

MR. BROWN: Yeah. Unlike what happened in (indicernible), right, we're growing connected, so we call it Neighbor Seven Neighbor's Rights, so we have the ability to actually blow power across the different RTA equipped plants throughout the eastern interconnection. In terms of your transmission question, we do what we call a (indiscernible) transmission plan. There's features one, two and three. Look at that. In that reliability imparative document, which is the third document that you see in your package, it actually outlines our recommendations, in terms of what needs to take place to fill those gaps as you called it, but that requires a lot of discussions between the different -- because we're talking about 15 seconds, right? They have different plans, and then you're talking about the costs of those things. Who's going to pay for it, as we build these assets.

So that is the key. When you talk about an RTO, remember we don't own any of these assets, right. We're more like the air traffic controller of these assets. So what we're doing is compiling information and the input from our stakeholders to talk about what's needed and why. And getting the buy-in from (indiscernible) in terms of (indiscernible).

MS. KEOGH: All right. Thank you. Director Pfalser, I'll let you offer any questions you have for MISO.

MR. PFALSER: Mr. Brown, if there's a new entity power plant, the generation plant that's being built, do you all have -- does MISO have any inputs over what type of generation -- fuel their using to generate?

MR. BROWN: Yeah. So that decision is being made, you know, by the state. That is not -- we're tasked more so with managing what assets are available.

MR. PFALSER: Are available, okay.

MR. BROWN: Correct. And so we're not tasked with deciding. We don't have that authority.

MR. PFALSER: Okay. And you don't decide who can be at the (indiscernible) or not?

MR. BROWN: Well, we decided from a market's perspective, like as an RTO, we're -- you know, our goal is to ensure that customers -- we're operating that in the lowest possible costs. So as Chairman Thomas pointed out earlier, we're going to, you know, issue the guidance, in terms of who's generator facility is running first, based on the cost. So we're going to go for the least cost (indiscernible) to meet the demand for that day.

MR. PFALSER: Okay. And the last I have is can you give me an example of a renewal energy source that is not intermittent?

MR. BROWN: All of them are intermittent, because you're talking about -- are you talking about solar, or are you talking about wind? That's the key, so I cannot say a renewal source at this time -- the only way that I -- I know there's some work that's taken place. And there's some efforts that are taking place currently (indiscernible), but that is the only member of (indiscernible) looking at the renovation perspective. And I can speak to details of that, but that is one of our (indiscernible).

MR. PFALSER: Thank you.

MR. BROWN: You're welcome.

MS. KEOGH: Director Bengel?

MR. BENGAL: Probably one of the sources of (indiscernible) would be natural gas, or electricity breakdown (indiscernible). Quick question: When you looked at the -- on page 12 of your testimony, you talked about considering formalizing (indiscernible) expanding the (indiscernible) illicited testimony for the aging community. We've had a lot of communication back and forth, which seemed to work very well. What kind of formalizing are you referring to doing, beyond what you do now?

MR. BROWN: Yeah. So we communicate on a regular basis. We communicate to our neighbors, STP, as well as our members on a regular basis throughout the -- you know, we had practice and renew, some readiness drills and workshops saying winter. So there's a lot of communication that takes place, but what I think needs to take place, and I'm sure (indiscernible) others, based on my experience with Georgia Power, they're having conversations about those critical assets and, you know, hospitals and things of that nature, and clearing the roads in certain areas, just to make sure that fuel could be delivered, in terms of (indiscernible) diesel. But that ad hoc meeting was more so who was having the issue at that time. We all got on the call and thanks to Chairman Thomas for helping me pull that together that day, to just talk through where we were seeing issues from all of our members. How could they assist? And so I think expanding what happened that day with the state troopers that were helping to guide Mayor Scott that was using some of the equipment that City of Little Rock provided to actual clear for those critical assets.

Just those kind of conversations, rather than doing it on the spot that we actually started doing more quarterly meetings, or semi-annual meetings, such as will be due with our summer (indiscernible) and workshops that it be more private -- public partnerships in that discussion. Basically, this task force, plus us, in terms of our plans.

MR. BENGAL: But that would be something that would come from a state agency like PSE or the industry do that together? What would be the best focal point to formalize that?

MR. BROWN: I definitely think (indiscernible) is the right place to start. I mean, Chairman Thomas, I made the call to him, saying "Hey, here's a thought I had," and really he had the relationships, me being fairly new to there, seeing how I pulled that all together. It was effective and (indiscernible) that probably wouldn't have been able to do that, if it wasn't for that conference call.

MR. BENGAL: Just one more. What's the mix of fuel or energy sources in detail?

MR. BROWN: I hate I left my phone back. I could tell you what it is, at this moment. We have an app, right. It's a MISO app. If you were to look at that MISO app, it'll show you our fuel mix at any minute, right, of what's taking place. So what I would tell you is where is the -- you know, when you talk about communication, most of our members now have apps, as well as us, to ask any question of what is it at any particular time, so that notifications that we were actually sending via test message or email, depending on the regulators and how they told us they wanted us to communicate to them. That app now will probably answer 90 percent of the questions, and we'll keep enhancing that as we go forward.

MR. BENGAL: And in the beginning of your testimony, you said this was only a second time you had to have a load shed event --

MR. BROWN: That's right.

MR. BENGAL: -- in your area. Is that because of the mix of energy you have, or was that for gas as the component in your area, as opposed to request?

MR. BROWN: I think it's just the fact of, you know, what an RTO is, right. We're able to leverage, you know, energy from other locations. PJM for instance, right, we've got at least 13,000 mega watts on a particular day that flowed from north to south. So, you know, sometimes (indiscernible). So the fact that we're interconnected is really the key thing in my opinion, to being successful at keeping the reliability where it is today.

MR. BENGAL: And if you look at the (indiscernible) one time hopefully event, but you said it compared to potential summer events.

MR. BROWN: Yeah, in terms of peak loads, right. So you know, we actually have another (indiscernible). I didn't include that one, on (indiscernible). As more, you know, units are more electric than they are gas, right, that's going to command -- that's going to increase demand. Same way when it comes to the electrication of vehicles, seeing more and more electric cars versus gas. Those are -- those are going to keep increasing and so that's a forward looking report, electrication report, and so --

MR. BENGAL: So we've got a lot more winter type events in the future, if we have (indiscernible) long periods of high temperatures, may result in the same type of event that we (indiscernible) energy usage.

MR. BROWN: Yeah. I mean, every event is unique, right, but when you look at the overall demand, the more demand, the bigger the risk in terms of those peaks and being able to meet those demands. The planning that Chairman Thomas referred to earlier, when you're building one of these facilities, it's not like you can say, "Hey, looks like we need more generation." You know, you can't do that in a matter of a year. We're talking about, you know, four to five years to build the land, once it's pruned and on to that process. So the process of making a committment of that nature and then digging through the cost and the benefits of that, for an everyday rate payer, that's a lot to consider. So those are questions that are separated and discussed everyday.

MR. BENGAL: Thank you.

MS. KEOGH: Thank you. All right. Well, again thank you so much. We have a pretty diverse mix today. I won't announce it, because I don't want to (indiscernible), but I'll tell you -- yeah, thank you so much.

MR. BROWN: Absolutely.

MS. KEOGH: Appreciate that. And thank you, as far as your communications and in communications and preparation. One of the benefits of transformation, under Governor Hutchinson's leadership was to bring our energy group, or executive agencies together and I know my (indiscernible) down the road, so let us know how we can assist you, as well going forward in addition to your Public Service Commission and your interactions.

MR. BROWN: Thank you.

MS. KEOGH: I will now ask Southwest Power Pool representative to come forward, state your name and organization. After that, we'll take a break and call -- I think we'll hear about the energy users, the four organizations we'll talk about as the consumer side of the energy sector.

MR. SUSKIE: Well, thank you. My name is Paul Suskie. I serve as the Executive Vice President and General Counsel for Southwest Power Pool. I've been here a decade now, and before that, I spent four years as Chairman of the Arkansas Public Service Commission, predecessor of Chairman Thomas. And before that, it's good to be home in many ways, I was the City Attorney for the City of North Little Rock for 10 years, when we ran the largest electric municipal utility in the state of Arkansas.

So collectively, I have about 24 years experience dealing with electric utility regulation and operations in some form or fashion. I appreciate the opportunity of the task force to come and speak about the Feburary 2021 winter weather event. I applaud Governor Hutchinson's leadership in creating this task force to take a look at this historic and challenging event. As we all know, and it's been refernced ealrier, this was a historic event. From a weather persepctive, some have referred to this as the 100-year storm.

The cold temperatures meant that well over 90 percent of our footprint was below zero degrees. I didn't say below zero. I said below zero degrees. This includes parts of our nation that is Texas, Louisiana and New Mexico that normally doesn't see these tempertures, let alone for several days in a row. The emphasis here is SPP has been in existence, an Arkansas organization, for 80 years. This is the first time, in the 80 years -- we were formed shortly after World War II began. We've never seen a load event, particularly of this magnitude, region wide. And also though this may be a first for the SPP region, this is not a first for this nation.

In 2011 Texas saw a major polar vortex in its state. In 2014, the east cost experienced one with the 2014 polar vortex. And then here in Arkansas, south central US, in January 2018, we saw a cold weather event. Due to the historic nature of this and the incredible implications its hard, it's a real opportunity to have lessons learned.

To get to some of the activities of what SPP has underway, two months from today our board of directors will be presented a comprehensive report of the winter weather event. This report is composed of reports from five different teams. These include stakeholders, our market monitor, our staff, as well as the Regional Safe Committee. The Regional Safe Committee is a committee that has governing authority in our governnce process. It composes a one state regulator from each state. I'm proud of the service Chairman Ted Thomas has on this organization, as he is a member of this committee. Obviously, I echoed your comments that we need to listen to Ted Thomas, particularly what he's talking about with these challenges.

In addition to what we're doing internally, on the lessons learned, we are also involved in a feud with the Federal Energy Regulatory Commission, primarily enforcement agency of the federal government and enforce the standards of the bulk electric system. And they're doing their inquiry in concert with the North American Electrical Liability Corporation, that enforces those regulations.

At a high level, I'm going to talk about the event and SPP's role is operating the electric for that. First of all, RTO's do not run generation and do not flue transmission. Matter of fact, because we are the grid operators we're prohibited from doing that. As an RTO, we operate a grid under a number of functions. These are highly regulated functions by Merk and Burk. I'll just talk about four of them.

One, is we are a transmission planner. In that role, we plan for the transmission grid of the future, wheher it's for liability reasons for economic reasons. We're a market operator. As Daryl discussed we -- and Ted Thomas discussed we administer wholesale electrical markets, where we deliver power reliably at the lowest cost to in use customers. And these roles are regulated by federal (indiscernible).

We're also the reliability coordinator, where we ensure that the reliability of the bulk electric system is maintained, whether it's a small event from a line goes out to a lightening strike, to a tornado, or it's an event like we had in February. And the last of the order y'all are talking about is what was really important to this event is (indiscernible). Does the (indiscernible) authority, what your job is to balance load, that's the demand of customers with generation of the system. If you have too much load, or too much generation, you can have lags. If you have too little generation and you don't do something about it, you can have blackouts. Well, that's what we faced in February.

On February 15th for the first time, we ordered one and a half percent of the load about 600 mega watts to be load shed, load ratio shared. In other words, spread throughout the foot print of 600 mega watts. And that was for about 57 minutes. On Tuesday, the next day, the 16th, we had two load sheds. One of 1200 mega watts and another of 1200 mega watts. Collectively, that was about 2500 mega watts and that lasted then different time increments, but two hours -- three hours and 27 minutes.

So why do we do this? We do this because if you don't load shift when you don't have enough generation, you can have cascading blackouts across the entire (indiscernible). When was the last time that happened? 2003. Because Midwest American doing a transmission line overload, doing blackouts that went to New York City and into Canada. There were parts of Canada that their power wasn't restored for seven days. So it's because of these items, is why we do what we do.

So one other thing I'd like to touch on, which was touched on by other speakers today is the price of natural gas. The price of natural gas for the last several years has been two to three dollars (indiscernible) during this event. And so while we look at how we pay for this event, there is challenges. There's a number of things to look at. The gas market, the cost of gas, we don't regulate. We're not involved. It directly impacts our market, because in most cases, it sets the price on the market.

I appreciate the opportunity to speak and I look forward to your questions.

MS. KEOGH: Well, thank you again, for sending your information forward. I'll start with a brief question of just the same one that I asked representative of MISO. The benefit of having the two of you (indiscernible) I hear in Central Arkansas that have the two RTOs bringing the school of opportunity, but are there any (indiscernible) in terms of making sure that the (indiscernible)?

MR. SUSKIE: Yeah, aboslutely. We coordinate with MISO on a number of areas. We plan (indiscernible) I talk about. We work on scenes, projects, and we do realtime operations. This event I think really shows the need to coordinate with your neighbors. We had more of a chosen generation loss than they did, becuase of the cold temperatures, and we just had another gas, coal and wind that wasn't produced. And as a result, we would've been much more worst off, except for that up from MISO. On a big day, we'll important 2,000 mega watts from MISO. We were importing 6,000 mega watts. Realize the interconnection of the grid, as Daryl told you, they were importing at the time 14,000 for the east. So in reality, 14,000 went from PGO to MISO and then MISO was able to send six to us. We got power from Canada at one point. We got power from Colorado at one point. We were loading up, sending as much power as we could to Texas, but when we got short, and we knew it was close to shedding load, but it cut power to Texas, and we all know that the need that they were in. It's highly interprotected. We work well together and I think the (indiscernible) need to work together more so.

And I'll point out in January of 2018 when we had the cold weather event here, there were a lot of lessons learned. There was an inquiry from FIR, similiar to the inquiry now about how can SPP and MISO coordinate. I think a lot of good recommendations came out of that. We implemented and they showed that they work through this event.

MS. KEOGH: Okay. Thank you. I will turn to Director Sparks?

MR. SPARKS: No questions. Good information. Thank you.

MS. KEOGH: Thank you. And now I'll go back to Director Bengal. Do you have a question?

MR. BENGAL: Just a quick question. The power that you purchased from other systems, what was the generating source of that power?

MR. SUSKIE: And I'll say in reality when you're buying electricity in that volume, you don't know what -- it depends on what they have on their system, in reality. That's a good question, but it's whatever power they have on the system.

MR. BENGAL: And with respect to natural gas, without natural gas disruption and we have say a long heat wave, summer event, you're -- how much capacity I guess is this and will that ever be an issue in the current (indiscernible), or would it become an issue, if you change the mix that we have now?

MR. SUSKIE: I'll start out by sharing our fuel mix. I might be off by maybe one or 2,000 mega watts, but our number one fuel capacity source is gas and about 35,000 mega watts. Next is wind at about 27,000 mega watts, and next is coal is about 23,000 mega watts. Does that help understand the importance of gas, and the need to have gas. Of those wind actually produce, roughly, as we estimated that it would. Coal produced about 75 percent of what we accredited for, and gas was below 50 percent. Whether the pipes were all fine breaking, or they just physically couldn't get the gas, or in some cases, they couldn't financially afford the gas. I know members that had to go to the banks and get loans, just to buy gas for the market, and when they went back, the gas was gone.

MR. BENGAL: Thank you.

MS. KEOGH: Mr. Pfalser, do you have a question?

MR. PFALSER: The question is concerning the comment that you made about -- correct me. They dictate that (indiscernible) by who generates electricity first? The cheapest?

MR. SUSKIE: Yeah. First of all, first sets the rules for the markets. They inherit market rules since you dispatch the cheapest energy first, and then you go up the --

MR. PFALSER: So the cheapest generation is going to be what you use the most of, until it can't produce anymore, and then you go to the next one and so forth and so on. So looking at the future, and this is almost incompatible. If the cheapest is going to be wind power, and that is what they ask that you do, then you can let one and two provide power (indiscernible) because they're going to be the first selected, it would appear. And that doesn't seem like a real good answer for a base load. Is that fair?

MR. SUSKIE: Yeah, but I would say I look at it different. Without market, you're going to dispatch cheapest first. It just makes sense. As a regulator, you're going to dispatch them cheapest generation first. But as Ted has pointed out, wind with the federal subsidy is it actually bids in the negative prices in the market, and so as a result, it's driven down market prices. And therefore, if you are not going to (indiscernible), meaning you have a state regulator that approves generation. They put in new rates and rate payers pay for it.

Vertically integrated utility has to bring up capacity and then they got to figure out what the right mix is.

But if you're (indiscernible) they have the vertical integration. They deregulate it. They don't have a capacity mark. It's truly freedoms of the market, and their prices got slowed -- so low, they had no new generation that they needed for this situation. So Arkansas is better protected than actually the entire SPP footprint is, because we're a vertically integrated state. And it does create a challenge, if we continue to move to renewals. The continueds have low prices and if you have a retirement of gas and coal plants, there's going to the challenges that you can't figure out. Part of the potential solutions batteries, but is still has It's intermittent problems , because we assume they only last about four hours, until they get a recharge.

MS. KEOGH: well, thank you again for your appearance, and bringing your presenation and testimony. I would like to take a moment to recognize Calay Stanton, who is here from

Governor Asa Hutchinson's office, supporting the task force. Thank you for your role in this process.

I know we have a number of other asteamed guests, including former congressmen, (indiscernible), so appreciate those of you that have been here today, and we will take a break for the purposes of the task force to give a moment. And then we'll reconvene to start the second round of speakers. So with that, we'll take a break and we'll reconvene at 3:00. Thank you so much.

(OFF THE RECORD)

(ON THE RECORD)

MS. KEOGH: It is May 27, 2021 and we appreciate all of you that are here in person, but also those joining us virtually and watching live stream. Those of us in person are here at the Arkansas Department of Energy Environment Headquarters Building here in North Little Rock and we're here to hear testimony for the Energy Resources Planning Task Force. I am Becky Keogh. I'm the Secretary for the Arkansas Department of Energy Environments and I got the pleasure of serving this task force, along with Secretary of Commerce, Mike Preston, Director of the Oil and Gas Commission, Larry Bengal and Kevin Pfalser, Director of the Little Rock Petroleum Gas Board. Today, we have with us Keith Sparks, Director Sparks, who is sitting the place of Secretary of Commerce, Mike Preston today. So we appreciate you being here today. The Secretary of Commerce could not be here due to out of state travel, but Steve Sparks is here. He is the Director of ADEC, Existing Business Resources Division.

On March 3, 2021 Governor Hutchinson signed Executive Order 2105 to establish the Energy Resources Planning Task Force. The purpose of this hearing is, incompliance with the order, to gather information from testimony in order to better prepare our state's energy infracture in the event of another statewide emergency. And that statewide emergency could be another storm event, but it also could be something different, so we want to make sure that we're considering all possibilities.

As chair of the task force today, I wanted to first extend my appreciation to those of you that are speaking to us or offering testimony.

Those of you that are in this session, we just completed the first session which comprised a number of the regulatory agencies, the AG's Office, as well as several other bodies, our regional transition organizations. But as we move into this next session, we'll be hearing from several organizations, regarding energy use and how you were effected during the February storm, and perhaps some recommendations that you might have.

Anyway, so I will call the name of the organization that will provide the testimony. When I call your organization's name please -- if the representative that's here to speak today, will come forward and sit at the mic. Make sure the mic is turned on. There's a bright green light when it's on. State your name, title, and organization for the record. We ask that the organization limit its testimony/presentation to five minutes. So if you have multiple speakers, I would ask you to share that time, if possible. And then after you complete your opening statements, I will then open the floor to the task force members to ask questions of each of those that are speaking. We've only alloted about 15 minutes for that Q and A, so I'll ask our task force members, as well as you and you response to keep mindful of the time, during those questions and if we need more detail, after a short response, we might want to follow up with you later, but please work with us on that if you can.

I'm happy to introduce Andrea Hopkins, who is sitting here at the front table. She is our timekeeper for the hearing and is doing a well job and allow us to catch back up. So please be respectful of the time limits that we offered you and that's only in respect of getting as much information as we can shared today, but also respectful of those others that are here to speak, and those that might have things to say.

I recognized earlier that we have visitors that are here with us. We have representatives of the Governor's Office. I appreciate that. Chairman Thomas has stuck around, so I appreciate that. Chairman Thomas spoke earlier from the Public Service Commission, and I know he -- they have their own assessment or evaluation going on, appropriately through the regulatory process, as well as the attorney general who spoke about that earlier. Their represenatives spoke about their own investigation, which has a bit different focus. The Governor's focus in this process is really about an after action assessment. Really, looking at lessons learned and how do we improve. So with that, we will try to keep our questions directed at that focus.

The first speaker we're asking to come forward is the representative from Arkansas Environmental Federation. And I will give you a heads up that the next speaker after this will be the Arkansas Electric Energy Consumers, so to better prepare the order. So with that, I'll turn the mic over to Ava and let her introduce herself.

MS. ROBERTS: I am Ava Roberts. The Executive Director of the Arkansas Environmental Federation. The AEF was founded in 1967 by industry members and the Arkansas State Chamber who saw a need for industry representation, concerning environmental regulation. We at AEF greatly appreciate the opportunity to participate in the Energy Resources Planning Task Force and thank the committee members and participants here today.

The questions that AEF received April 12, 2021 was circulated to members for a response. Member response was varied greatly, depending on company size and industry. The answers we received represent less than five percent of AEF member companies. AEF members that responded to our questionnaire filled the need for earlier and more detailed (indicernible) before facilities are asked to cartell operations.

The majority of AEF members that answered our questions said the curtellment during the load shed did not damage or reduce the effect of this environmental quality control equipment; however, those that did answer yes believed adequate notice and minimum utilities requirements are needed to mitigate equipment damage.

There were significant challenges to allocate energy resources, during these extreme events and the responses to this questionnaire stressed the need for earlier notification for internal planning. As the majority of AEF membership are manufacturers, there's no opportunity to negotiate processes with end users. AEF members have no suggestions for other entities to provide testimony before this task force. I appreciate your time today and will be glad to take any questions you may have.

MS. KEOGH: Thank you. I appreciate you being here. I appreciate the membership responding. I understand that you do represent a wide diverse group that may have different interest or even different experiences, during the February storm event, so thank you for that. And we appreciate the recommendations that have come forward. And that was one of the things that I heard, and the Governor heard, I know, was about early notice, and about even rolling blackouts we had. But also the notification process for natural gas curtailment, which was more, I guess, affected by your customer -- or your members. Is there any recommendations in the feedback, that they're giving, in terms of what the notification could, or should look like, except early and more often? Is there any more specifics that they would like to see either via technology or via timeframes or anything like that, that we can offer the Governor on report?

MS. ROBERTS: The list that responded did not go into that type of detail in their responses, but that is something that I will be happy to address with them.

MS. KEOGH: Well, thank you so much. Appreciate that. I think that will be helpful to me, anyway (indiscernible). So with that, I'm going to turn the mic over to Director Pfalser to see if he has any questions for you.

MR. PFALSER: Ms. Roberts, again, thank you for providing what you did and being here today. You all -- your organization helps your membership navigate the environmental regulation for the most part. Is that why you all exist?

MS. ROBERTS: That's right.

MR. PFALSER: Okay. And do you know -- do you have a feel your membership, if anybody has the ability for generating electricity on their own? If there was load shed and were taken offline, would they have the ability to continue to generate their own electricity?

MS. ROBERTS: I did not receive that specific information --

MR. PFALSER: So you're not aware of --

MS. ROBERTS: -- with regard to that. I'm not aware of that, but again if that's the will of the task force for me to, I will be happy to bring that to our members.

MR. PFALSER: I would be helpful, maybe, just to know if that is -- if there's anybody out there that's doing that, and to talk about the whole equation.

MS. ROBERTS: Absolutely.

MR. PFALSER: That's all I have.

MS. KEOGH: All right. Thank you, Director Pfalser. I'll turn to Director Larry Bengal and see if he has any questions.

MR. BENGAL: Thank you. In the interest -- I know it was a small (indiscernible) companies that you represented. Was there a difference between the (indiscernible) issue, with respect to electricity versus natural gas? MISO and SPP have fairly robust notice systems, so it should've been that variety, but I'm not sure with the natural gas industry has (indiscernible). We will probably hear some testimony on that, but did you see a difference between electricity notice and natural gas shut off notice, in your responses?

MS. ROBERTS: In the responses, I did not. They did not differientiate.

MR. BENGAL: Is there any way to surmise what they were talking about in the answers they gave you?

MS. ROBERTS: For the most part, the answers were very brief.

MR. BENGAL: Okay. That's all I have.

MS. KEOGH: And to that, Director, I want to let everyone know that the Department was contacted as well as, I believe, the Governor's Office regarding some -- from some (indiscernible) sites, regarding natural gas curtailment. I think it would be helpful to pursue if their concerns really were regarding the fuel supply, or if it was more around the electric cred, that would also help us, too.

How about you, Director Sparks? Do you have something?

MR. SPARKS: Very quick question. What size membershop do you guys have?

MS. ROBERTS: We represent roughlly 200 companies.

MR. SPARKS: Thank you.

MS. KEOGH: Wel, if the task force does not have anymore questions, I think we will close with this one. We appreciate your willingness to be here and your followup, and feel free to reach back out, if you have any information you want to share with us. Thank you.

Our next speaker is Arkansas Electric Energy Consumers. They are heading to the table, so thank you for that. Please be on standby. The next group will be Arkansas Forest and Paper will be the next speaker coming forward, so if you would like to start, I'll let you state your name, title, and organization.

MR. COUSINS: All right. May name is Steve Cousins. I'm the executive director of the Arkansas Gas Consumers and the Arkansas Electric Energy Consumers. I'm a licensed professional engineer in the state of Arkansas and have several decades of experience running an oil refining complex in south Arkansas, that was one of the largest electricity consumers in the state, and one of the largest natural gas consumers in the state. And one of the largest liquefied petroleum gas producers in the state.

MR. MCMURRAY: And I'm shown McMurray. Outside counsel for AEC and ADC.

MR. COUSINS: This event was really kind of a tale of two cities. Electric consumers, large investors and agricultural consumers. I'm not aware of a single one in the state that suffered a curtailment or an interruption, other than people that were intentionally on interruptible contracts. On the natural gas side, there was widespread curtailment. A lot of near misses, in terms of damages to equipment, or loss of poultry, and things of that nature.

One of the big reasons for that, is that Arkansas -- and our customers are Entergy customers, the largest utility -- can elect to be on interruptible tariff. And if there situation, if their business is designed in a way that they can pull the plug on operations very quickly, they can get a heafty discount on electricity costs that they pay, and because that was available, all of those customers, were curtailed, and that took a significant amount of load off the system, which helped prevent any kind of groundouts, or blackouts, but that kind of system doesn't exist in the same way on the natural gas side, and it will be very difficult to implement.

We think that the tariff is very important. We think it's important that it be a cost space, that it be preserved, or maybe even enhanced, because it's about the only tool that you utility has, to control the (indiscernible). The supply is diminished, and the demand has got to go down too.

On the natural gas side, most of our members, most natural gas users, that have facilities, that could be damaged by prolonged exposure to cold and freezing were not aware that there is a procedure to file a special needs, or plan protection affidavit, with the enable, the transporter that provides Centerpoint its gas, to preserve a minimal amount of natural gas, to protect equipment and lives, by not letting the facility be damaged, and what could be damaged by cold-weather.

There was no real education on that and since we hadn’t had an event like this in over 30 years, many industrial and agricultural customers, simply didn't have that in place. We tried it. And once the event starts, we really don’t have time to file the affidavit. So we think there is a need for education, among natural gas customers. There is a way to move up on the pecking order, for an industrial facility or an agricultural one, if you do the paperwork in advance.

We also think, that is very important that curtailments be notified as soon as possible, and we haven’t heard instances of people showing up the day of the facility, with a high branch and saying, turning you off right now. And that hardly gives people time to prepare. While you’re serious on the natural gas side, which the AG’s office already testified about, was that there are many customers that buy gas on a spot market price basis. The system is pretty complex. You got the natural gas producer, the schedulers, the managers. You got the federally regulated pipeline, and then you got the state regulated local distribution system, and the price is being set at the producer end, and it's got to go through this chain of people. Many people thought they were paying three dollars a million BPs for gas, and they were paying 300. So they made a run out of almost a whole year's worth of bills in just a day or two. And had they known, they certainly would've shut the facility down, and avoided that cost. It's very much the same system that some of the cities have, municipalities. So some kind of real-time crisis (indiscernible) would be very important, to avoid the serious and common consequences that exist. I that concludes...

MS. KEOGH: Thank you. Sean, did you have anything you'd like to bring?

MR. MCMURRY: No, thank you. I think Steve covered it.

MS. KEOGH: Okay. Great. Those are excellent observations, consistent with what we hear at the Department, in terms of stories that were being brought to us during the event as well as after. And also some interesting recommendations. I think those are very thoughtful and appreciate. That will help us in our report.

One of the questions I was going to earlier pose to you was in the affidvit of process, you know, was is the -- is there an education process in existence, and is there a need to have some required notification process, do you believe from a (indiscernible) standpoint, or just a more market for our industry practice, that you would like to see a best practice implemented?

MR. COUSINS: On the elective side, the tariff has notification requirements spelled out, and we believe the utilities all follow those procedures, you know, as far as we know, 100 percent. So it's hard to complain without about interruptable customers in the manner in which they were curtailed. They signed on for that intentionally.

On the natural gas side, the special-needs waiver is in the tariff, but not the many people were aware of it. Natural gas supplies in Arkansas have been pretty robust over the years, even through the varied events. This is just kind of unforseen and maybe it’s the way of the future. I don't think there's anything in the tariff that talks about particularly sets notifications, and pre-advance warning times, or anything of that nature.

MS. KEOGH: Yeah, I'm more of a state facility, that actually experienced what you described, where the gas company shut off the gas to that facility. So it wasn't just private sector; it was across the public sector, as well. So with that, I appreciate you, but I want to turn to -- I guess I'll go to you Director Sparks.

MR. MCMURRY: Chairman Keogh, I just wanted to say on the electric side, what Steve said is correct, the notification provision to the tariff right now work. And we want to make sure -- one of our invitations was to make sure that those notification provisions were met, if there's talk of changing some of the interruptable in the future proceedings. So that's one very important thing, to maintain that level.

MS. KEOGH: All right. I'll turn it over to you, Director Sparks.

MR. SPARKS: Yes, Mr. Cousins, what would you recommend that you educate folks about the gas side of it? That they got caught shorthanded with the knowledge of -- that (indiscernible) happened, and the price change from consumer to producer on that?

MR. COUSINS: I think that's the situation right -- I recognize the problem. I don't know what the solution is. I would assume it could -- I'm not really sure what regulates the actual purchase of the gas from a well head producer. That's not in the tariff. That's a private contract between the end user and that producer. I suppose statutorily, you could have a requirement that that be included in the contract and some notification, but I think now, people are a lot wiser and they're going to build that into the private contracts. And I'm not sure if regulatory vagueness would solve that. And it's interstate most cases. Most of that gas is coming from outside of Arkansas.

MR. COUSINS: Thank you.

MS. KEOGH: Director Bengal, did you have a question?

MR. BENGAL: A couple of things. You talked about discussions to change some of the interruptible notices. Who brings on -- how are those discussions, occurring through the state elections?

MR. COUSINS: Those tariffs are in the utility tariffs regulated by the Public Service Commission.

MR. BENGAL: Okay. So those are in-state discussions?

MR. COUSINS: Those would be in-state discussions on the electric side, yes.

MR. BENGAL: And the special-needs waiver, is that filed with the distribution company, or the gas transmission --

MR. COUSINS: I believe that's filed with --

MR. BENGAL: With the pipeline?

MR. COUSINS: The interstate pipeline that's regulated by ARC. And if that has been filed then Centerpoint will recognize that.

MR. BENGAL: So you would have to know as a user, which transmission line --

MR. COUSINS: Yeah, the large industrials typically rent space on Centerpoint, and then that enables whoever their interstate pipeline is. They pay only for transmission. It's already been deregulated, as opposed to electric.

MR. BENGAL: This means to file your waiver, you have to file it with --

MR. COUSINS: So any individual customer will have a contract with enable, through Centerpoint, and some customers are directly on enable, and don't even utilize it.

MR. BENGAL: You know, gas prices are probably one of the most complex pricing structures that mankind has ever acknowledged. If you can figure it out, you'll make $1 million. But given that, what would be the mechanism to think a user able to find when that price he was paying changed between Thursday and the next week?

MR. COUSINS: I think it would just have to be a written contract with the producing company you're buying from, that they -- that you have a way to access the spot price that they're charging you, in any particular event.

MR. BENGAL: So there should be a notice from --

MR. COUSINS: And many customers don't buy a spot. Many customers -- I know in my own experience, we bought gas that was based on the future's prices, and could buy it ahead of time, and it couldn't take off on you. In a situation like this, I'm sure suppliers would enforce and not be bound to that price, if they didn't have any gas to deliver.

MR. BENGAL: So it would be contractual notice?

MR. COUSINS: It would be contractual.

MR. BENGAL: Not a regulatory requirement?

MR. COUSINS: No. And usually those spot prices are publicly available on, you know, (indiscernible) that there indexes that track that price, all the time, and then some form you'll agree that, is what applies to -- in the case to the people that got bit by this in Arkansas. I don't have enough knowledge to know how they're pricing them, just that they were not filing, because it generally wasn't their --

MR. BENGAL: So in the contract, they would have instead of (indiscernible) it would be in the contract that Centerpoint would tell them, hey, we're now shipping from three dollar gas to thousand dollar gas?

MR. COUSINS: Yeah.

MR. BENGAL: And I assume there's -- other than being contractual from the interruptable aspect, it's harder to use that for gas.

MR. COUSINS: It is. A lot of when you get pipeline (indiscernible) or you elect a certain number of a million BTUs worth in that pipeline you can get it at firm delivery and you can get interruptable on top of that, but this case it wasn't a problem with the pipeline. The problem it was no gas in the pipeline. So that kind of mechanism -- the mechanisms that's there and handle pipeline capacity now, just to prevent over-filling the pipe. It doensn't really address what happens if there's no gas to go in.

MR. BENGAL: And one last thing. Do you have any -- I'm not sure you would, but do you have any feel for how decisions were made on who got their gas shut off and who didn't?

MR. COUSINS: No, I do not.

MR. BENGAL: That's all.

MS. KEOGH: Well, thank you very much. Well, thank you. I will ask you one more question. Since he represents the (indiscernible) industry, are there industrial customers or consumers that y'all represent that were affected by any kind of propane shortage in this, or any liquified petroleum shortages? I know we experienced some of that in certain regions of the state.

MR. COUSINS: I don't know. I think probably the biggest single problem would be truck traffic was hampered so bad by the icy roads. You know, if you used up LPG you had in your tank, it might be very hard to get somebody back up there to resupply it. I do not know if there was a problem on the supply end, from providers of natural gas companies that sell LPG.

MS. KEOGH: Yeah. I talked to one propane dealer, one of our state senators who mentioned that he was on the road daily, during the event making sure that his customers got delivery. So with that, thank you, again for your time.

(WHEREUPON, the proceedings were concluded in this matter at 4:12 p.m.)

CERTIFICATE

STATE OF ARKANSAS)
)ss
COUNTY OF PULASKI)

I, Tiffanie N. Harrison, CCR, Certified Stenomask Reporter before whom the foregoing testimony was taken, do hereby certify that the witness was duly sworn by me; that the testimony of said witness was taken by me and was thereafter reduced to typewritten form under my supervision; that the deposition is a true and correct record of the testimony given by said witness; that I am neither counsel for, related to, nor employed by the parties to the action in which this deposition was taken, and further, that I am not a relative or employee of any attorney or counsel employed by the parties hereto, nor financially interested in the outcome of this action.

I FURTHER CERTIFY, that I have no contract with the parties within this action that affects or has a substantial tendency to affect impartiality, that requires me to relinquish control of an original deposition transcript or copies of the transcript before it is certified and delivered to the custodial attorney, or that requires me to provide any service not made available to all parties to the action.

WITNESS MY HAND AND SEAL this 2nd day of July, 2021.

Tiffanie Harrison

TIFFANIE N. HARRISON
Arkansas State Supreme Court
Certified Court Reporter #757

ARKANSAS SUPREME COURT
TIFFANIE HARRISON
No. 757
CERTIFIED COURT REPORTER

ENERGY RESOURCES PLANNING TASK FORCE

PUBLIC HEARING AGENDA

TUESDAY, JUNE 1, 2021

10:00 a.m. – 4:30 p.m.

10:00 a.m. – 11:30 a.m.

Call Meeting to Order

Public Hearing Guidelines:
- Task Force Chair will moderate
- Testimony will be limited to five minutes
- Q&A will be limited to fifteen minutes

Order of Testimony:
1. Black Hills Energy
    - Tom Stephens, Director Regulatory and Finance
    - Chad Kinsley, Vice President of Arkansas Operations
2. Centerpoint Energy
    - Miles Kenny, Vice President Gas Supply
    - Cindy Westcott, Regional Vice President of Operations
3. AIPRO
    - Rodney Baker, Executive Director

11:30 a.m.

Recess for Lunch
Lunch will be provided for Task Force members

1:00 p.m. – 2:45 p.m.

Call Meeting to Order

Public Hearing Guidelines:
- Task Force Chair will moderate
- Testimony will be limited to five minutes
- Q&A will be limited to fifteen minutes

Order of Testimony:
1. Arkansas Electric Cooperatives
    - Andrew Lachowsky, Vice President of Planning and Market Operations
2. Arkansas Municipal Power Association
    - Travis Matlock, City of Bentonville Electric Utility Director
    - Jason Carter, AMPA General Counsel
3. Empire Municipal Electric Company DBA Liberty Utilities (ZOOM)
    - Joelle Cannon, Director of Government Relations
4. Oklahoma Gas and Electric

- Don Rowlett, Managing Director Regulatory

5. Southwestern Electric Power Company (SWEPCO)
   - Bradley Hardin, State Government Affairs Manager

3:00 p.m. – 4:30 p.m.

Call Meeting to Order

Public Hearing Guidelines:

- Task Force Chair will moderate
- Testimony will be limited to five minutes
- Q&A will be limited to fifteen minutes

Order of Testimony:

1. Entergy
   - Laura Landreaux, President and CEO
   - John Bethel, Director of Public Affairs
2. Energy Policy Network
   - Randy Eminger, Executive Director
3. Jackson Walker
   - Michael Nasi, Partner
4. PPGMR, LLC
   - John Pieserich, Attorney

ENERGY RESOURCES PLANNING TASK FORCE

MINUTES

DETAILS

Date and Time:	6/1/21	Session 1: 10 – 11:30, Session 2: 1 – 2:30, Session 3: 3 – 4:30
Location:	Department of Energy and Environment (E&E) Headquarters, Live streamed on Arkansas PBS	
Subject:	Public Hearing	

Task Force

Becky Keogh, E&E Secretary, Task Force Chair

Kevin Pfalser, Liquefied Petroleum Gas Board Director, Task Force Member

Lawrence Bengal, Oil and Gas Commission Director, Task Force Member

Mike Preston, Secretary of Commerce (Morning Session)

Steve Sparks, Director, Arkansas Economic Development Commission. Existing Business Resources, representing Mike Preston, Commerce Secretary (Afternoon Sessions)

Other Attendees

Chad Kinsley, Vice President of Operations**,** Black Hills Energy Arkansas, Inc.

David Brink, Senior Manager, Black Hills Energy Hills Energy Arkansas, Inc.

Tom Stephens, Director, Regulatory and Finance, Black Hills Energy Arkansas, Inc.

Miles Kenny, Vice President of Gas Supply, Centerpoint Energy, Inc.

Cindy Westcott, Vice President of Regional Operations for Arkansas and Oklahoma, Centerpoint Energy, Inc.

Rodney Baker, Executive Director, Arkansas Independent

Producers and Royalty Owners

Travis Matlock, Electric Utility Director for the City of Bentonville, Arkansas Municipal Power Association

Jason Carter, General Counsel, Arkansas Municipal Power Association

Aaron Doll, Senior Director of Energy Strategy for Liberty Utilities Co./Empire Municipal Electric Company Co.

Nate Morris, Director of Transmission Planning Operations, Empire Municipal Electric Company/Liberty Utilities Co.

Tim Wilson, Vice President of Electric Operations for Empire Municipal Electric Company/Liberty Utilities Co.

Donald Rowlett, Managing Director of Regulatory Affairs for OGE Energy Corp.

Bradley Hardin, Manager-Government Affairs, Southwestern Electric Power Company

Andrew Lachowsky, Vice President of Planning and Operations for Arkansas Electric Cooperative Corporation

Laura Landreaux, President and CEO of Entergy Arkansas, LLC

John Bethel, Director of Public Affairs for Entergy Arkansas, LLC

Randy Eminger, Executive Network, Energy Policy Network

Michael Nasi, Jackson Walker, Attorney

John Peiserich, PPGMR, LLC, Attorney

	Shane Khoury, E&E	**Donnally Davis,** E&E
Andrea Hopkins, E&E	**Daniel Pilkington,** E&E	**Troy Deal,** E&E
Tricia Treece, E&E	**Beth Thompson,** E&E	

AGENDA ITEMS

1. Call to Order **Secretary Keogh**

Secretary Keogh, as Task Force Chair, called the meeting to order at 10:04 am. Secretary Keogh explained hearing logistics. For each organization, opening testimony was limited to five minutes with up to fifteen minutes for questions and answers from Task Force Members. Opening logistics were repeated at the start of each session.

2. Summary of Testimony from Chad Kinsley, Vice President of Operations and David Brink, Senior Manager, Gas and Supply **Black Hills Energy**

Mr. Kinsley distributed a handout to Task Force members providing an overview of Black Hills Energy. Mr. Kinsley explained that during the February 2021 extreme weather event, they exceeded their prior system peak by more than 20%. Their investments, team and messages to conserve energy allowed them to meet the extraordinary demand. Mr. Kinsley explained that they contacted large volume customers in advance to prepare for curtailment and encouraged energy conservation through direct communication, broadcast, social media, and their website. On February 16, Black Hills received Force Majeure notices from suppliers due to compressor failures and freeze offs. Service to Pea Ridge was lost.

Mr. Kinsley explained that they file an annual natural gas supply strategy. Storage in the central region is an important part of this strategy. Mr. Kinsley emphasized the importance of having a supportive regulatory environment for production, storage, and pipelines.

Mr. Kinsley encouraged close coordination between electric utilities and gas utilities in the event electric utilities find it necessary to implement rolling blackouts. When power comes back online, it can cause surges in gas demand and strain resources. Mr. Kinsley also recommended sharing additional communication to customers to provide awareness of financial help.

The Black Hills representatives were asked how to continuously improve what we do and respond to changing conditions. They were also asked whether they had any customers caught off guard with respect to not having a special needs affidavit and if there was anything that can be done to minimize costly damage to equipment. Mr. Kinsley responded that Black Hills hadn't had to curtail for 25 years. They reached out directly to large volume customers informing them of potential curtailments. Mr. Kinsley indicated there may be opportunity for educating customers.

The Black Hills representatives were asked whether there had been any follow-up on the Pea Ridge curtailment. Mr. Kinsley explained that Black Hills had been communicating with city leaders to make them aware of the situation and also took out newspaper ads to make the community aware. They have started building a new pipeline to the community.

The Black Hills representatives were asked how they can assure new industrial companies wanting to locate into the area of the availability of gas supply. Mr. Kinsley explained that the need for additional capacity in the Pea Ridge area was a known issue. Black Hills uses modeling systems to plan for capacity to meet the growth expected in decades to come.

The Black Hills representatives were asked why there is opposition to natural gas for heating homes and electricity. Mr. Kinsley responded that natural gas is working to tell their story about how gas has offset worse greenhouse gas emitters (coal). He suggested that the industry needs to tell their story better.

The Black Hills representatives were asked about any steps the state could take if equipment in another state is frozen and can't be delivered. Mr. Kinsley suggested that we could look at developing Arkansas's energy resources. The Oil and Gas Commission or other entities could study whether facilities could be transitioned to natural gas storage. On the demand side, Mr. Kinsley suggested that the state could look into expanding energy efficiency programs to reduce or slow the demand growth for natural gas.

The Black Hills representatives asked whether large users have the ability to store fuel on site. Mr. Kinsley answered that the economics for storage on site aren't favorable due to low natural gas prices.

The Black Hills representatives were asked if incentives would help, to which they responded yes.

The Black Hills representatives were asked if gas that serves Arkansas is coming from Oklahoma/Texas, which was confirmed by Mr. Kinsley.

The Black Hills representatives were asked whether weatherization would have prevented the supply shortages. Mr. Brink responded that most of their gas is purchased from an upstream supplier. The further north you go, you will see weatherization to a certain extent. Mr. Brink indicated that addressing well head freeze offs would be between the states and producers to identify what requirements should be.

The Black Hills representatives were asked whether they were aware of any state incentives/policies around weatherization of natural gas production resources. Mr. Brink said that there were not any in existence, but that Texas is looking at a bill that would establish weatherization requirements.

The Black Hills representatives were asked whether storage facilities played a role during the February 2021 winter weather event. Mr. Kinsley responded that two storage facilities in the Ozarks played a huge role.

The Black Hills representatives were asked whether they were looking into additional storage areas. Mr. Kinsley responded that there was an opportunity to look for additional reservoirs that could be storage facilities.

The Black Hills representatives were asked whether it is feasible to notify gas users if there will be a change in price. Mr. Kinsley explained that many of their customers purchase gas from third-party suppliers. Black Hills is not part of the transaction. He suggested that they could build something into their contracts with suppliers.

The Black Hills representatives were asked whether it is feasible to use an interruptible tariff for natural gas to encourage voluntary curtailment. Mr. Kinsley explained that Black Hills does not currently have an interruptible gas tariff. They would need to look at opportunities to develop this. Most customers would want to retain some level of usage.

3. Summary of Testimony from Miles Kenny, Vice President of Gas Supply and Cindy Westcott, Vice President of Regional Operations for Arkansas and Oklahoma **CenterPoint Energy, Inc.**

Mr. Kenny discussed CenterPoint's focus on a diversified portfolio of supply products to ensure that they can distribute gas to its customers during all months and weather scenarios. See CenterPoint PowerPoint slides for additional information presented in opening testimony.

CenterPoint representatives were asked whether they had any recommendations on what a customer could do on the front-end to voluntarily curtail if cost exceeded a certain level or if they could set a hard line on the amount of gas they need to receive to avoid catastrophic damage to equipment. Mr. Kenny responded that the broader you cast your net for upstream suppliers, the more protective the system is from cost spikes. Mr. Kenny explained that their diverse supply portfolio provides some shielding from high day market prices. Mr. Kenny suggested that the consumer would need to work out voluntary curtailments and price signaling with their supplier, not CenterPoint. Mr. Kenny explained that when CenterPoint went through the curtailment process, it was based on upstream supply and the need to maintain broad reliability.

The CenterPoint representatives were asked about whether they were in the position to make a decision about preventing catastrophic damage to equipment in the event of a potential curtailment. Mr. Kenny explained that the customers need to work with their upstream supplier to understand demand and plan accordingly.

The CenterPoint representatives were asked whether there were plans to have more communication among suppliers, the pipeline, and customers next year. Mr. Kenny explained that it was already happening. Some customers are wanting to leave the Transport customer class and go to sales. Some customers are looking at onsite back up.

The CenterPoint representatives were asked about the suitability of liquefied natural gas as a backup asset. Mr. Kenny explained that liquefied natural gas may work best when there is a longer lateral with a supply issue at the end of the line to add reliability and balance. It has not been needed in Arkansas, but they are constantly evaluating scenarios and how they would impact customers.

The CenterPoint representatives were asked about their statement that 50% of their gas used was from the summer and if this was futures pricing issue. Mr. Kenny explained that part of the way a storage facility worked was injecting supply during summer lower demand months when gas is cheaper and then using it during higher demand winter months.

The CenterPoint representatives were asked if they know a reason why the government should be opposed to the use of natural gas. Mr. Kenny responded he didn't see a reason for that.

The CenterPoint representatives were asked about their service area. Mr. Kenny explained that they serve eight states with supplies in multiple states.

The CenterPoint representatives were asked about where gas was stored. Mr. Kenny explained that the storage was on the Enable system and that he wasn't sure where storage sites are located.

The CenterPoint representatives were asked whether CenterPoint is part of an effort to look for more storage. Mr. Kenny explained that they recently made a reduction in storage to bring in more baseload market area supply. He emphasized getting to an overall diversity of supplies. Mr. Kenny explained that active supply is flowing every day, not sitting underground in storage. He explained that he wouldn't say one way is more reliable than another. In some cases well head supply failed and storage failed in others. Mr. Kenny explained that they want to have as many supply options as possible.

The CenterPoint representatives were asked whether there was something that CenterPoint and other companies could do to better notify customers of curtailment. Ms. Westcott responded that the events of February 2021 leading to curtailment happened quickly. She explained their use of media notices and press releases to notify customers of potential curtailment. She also explained that CenterPoint has over 600 transportation customers that contract directly with suppliers. Maintaining up-to-date contact information with these customers and having more staff to make calls would be an opportunity to provide better notification if something like the February 2021 weather event were to happen again. Ms. Westcott explained that, at the time, they had employees responding to emergencies and at times having to drive in hazardous conditions to go shut a customer off. Ms. Westcott indicated that there are opportunities for more robust education about transportation contracts and managing energy.

4. Summary of Testimony from Rodney Baker, Executive Director — Arkansas Independent Producers & Royalty Owners, AIPRO

Mr. Baker explained that the association didn't respond to the written testimony questions but could provide general information from producers. Mr. Baker explained that the February 2021 winter event caused hardship for producers. Mr. Baker described the imbalance between heating equipment and wells. Mr. Baker explained that top producing wells were prioritized and that staff worked around the clock, including spending the night at well sites.

Mr. Baker was asked whether he knew if all of Arkansas's wells were able to produce during the event. Mr. Baker explained that in some cases producers were totally shut out. They prioritized more productive wells. Mr. Baker explained that even though Arkansas production areas are fairly dry, there is still some separation of liquids and that separators can freeze up shutting out the well. If wells get froze in, the producers convey that information so the transporters can adjust pressures. Mr. Baker explained that keeping the roads open was important for their access to the wells. He suggested that other resources, such as the national guard, could have been used to keep the assets open.

Mr. Baker was asked whether he had any thoughts or recommendations for the Task Force to consider. Mr. Baker suggested that compressors should not be included in electricity curtailments. He also suggested providing more consumer education and suggested that having recreational housing temperatures turned down when they are unoccupied could help. Mr. Baker also emphasized keeping electricity at facilities that are moving gas and keeping roads open is important.

Mr. Baker was asked about weatherization efforts in the northern part of the state. Mr. Baker responded that many companies tried to borrow heater facilities to keep wells thawed out. They had approximately 60 units that they could access, but thousands of wells. He said he couldn't speak to the producers' thoughts, but the cost of being prepared for a fifty year event may not be feasible.

Mr. Baker was asked what percentage of Arkansas gas production remains in Arkansas. Mr. Baker did not know. The gas is sold through a third party and much of the shale gas goes out of state. In a simplistic sense, Arkansas had natural gas for use in the state before increased production of Fayetteville shale supply. Because the infrastructure was in place, shale gas was piped out of the state.

Mr. Baker was asked about whether the three operators in the Fayetteville shale region were looking at weatherization issues. Mr. Baker said that he assumes they are, but that they haven't met in a format where it could be discussed.

Recess **11:18 – 1:06**

5. Summary of Testimony from Travis Matlock, Electric Utility Director for the City of Bentonville and Jason Carter, General Counsel for Arkansas Municipal Power Association

Arkansas Municipal Power Association (AMPA)

Mr. Matlock explained that association members are diverse in size and ways of providing power. Options are based of diversified risk, assets, contracts, and ownership. For example, Jonesboro has a fixed price and own their own assets. Their prices were not impacted by the February 2021 winter event. For some, a third party manages aggregated risks under a full requirements contract. For example, Bentonville has a long term contract with SWEPCO. During the storm, they didn't experience curtailment or outages, but there was a significant increase in the fuel bill. Their typical fuel bill is $4 million for the month of February. This February, their bill was $20 million, almost half their annual budget. Bentonville is working with SWEPCO on an audit of bills.

The AMPA representatives were asked about what the state can do to make sure there is diversity and to make better use of baseload power during excess demand events. Mr. Matlock explained that members with long-term contracts with an outside provider are wholly reliant on that provider. Mr. Carter explained that this is true in any city with full requirement contracts. Mr. Carter said that access to natural gas is important for efficient behind the meter gas generation.

The AMPA representatives were asked what could be done to improve access to natural gas for cities with generation assets. Mr. Carter explained that, during an emergency event, there is a need to understand how to best direct gas when resources are constrained. Gas is needed to heat homes but it is also needed to generate electricity to operate fans to drive the warm air into the homes. This means that some industries may not get gas if we are prioritizing the needs of society.

The AMPA representatives were asked how many of their members have generating capability and whether those generating assets were fossil fuel powered. Mr. Carter said that about half of the members have generating assets. Most of the recent additions have been renewable. North Little Rock owns a hydro facility. Most other developments have been solar. Mr. Carter explained that some members do have some older natural gas or diesel driven facilities for generation.

The AMPA representatives were asked whether renewables could be used for baseload. Mr. Carter responded no.

The AMPA representatives were asked whether the planned obsolescence of fossil fuel generators could be a problem down the road. Mr. Carter explained that there are a lot of environmental concerns related to the consumption of fossil fuels for electricity. He emphasized that the most important thing is to provide reliability. When reliability fails, people lose their lives. Mr. Carter explained that natural gas is a critical fuel and that there is debate about its long-term use or use as a transition fuel.

The AMPA representatives asked whether the freezing problems with natural gas might have been avoided if there had been weatherization in place and whether they have any recommendations. Mr. Carter indicated that thinking about how much is enough is relevant for weatherization. Do you plan for the 100 year event? Mr. Carter stated that AMPA members worked to protect control panels, valves, and switches and still had challenges with the temperatures we had.

The AMPA representatives were asked whether the increase in cost was due to electric or gas, to which Mr. Carter responded that it was the gas prices.

6. Summary of Testimony From Aaron Doll, Senior Director of Energy Strategy, Nate Morris, Director of Transmission Planning and Operations, Tim Wilson, Vice President of Electric Operations

Empire Municipal Electric Company/Liberty Utilities Co.

The representatives from Empire explained that the primary causes of the curtailment event were 1) the extreme weather conditions (both cold and snowfall), 2) simultaneous record-breaking demand peaks with fuel supply disruptions, and 3) transmission issues. The Empire representatives explained that they issued alerts to customers asking folks to conserve energy, curtailed some large commercial and industrial customers, and employed controlled interruptions in one hour blocks.

The Empire representatives were asked whether they had any recommendations to encourage customers to volunteer for curtailment to prevent cost increases or mitigate damage. They were also asked if there were any lessons learned on notifications to customers. The Empire representatives explained that they have an interruptible tariff to incentivize voluntary curtailment. Empire reached out to customers with curtailable contracts and others. The Empire representatives emphasized the need to prepare and have contacts and relationships established. Empire representatives described the cooperation between the utility and industrial customers, including some industrial customers, who curtailed for a sustained period without even being asked.

The Empire representatives were asked if there was anything that they could have looked at in hindsight that they weren't aware of at the time. The Empire representatives explained that they felt prepared from an emergency operations procedures standpoint. These were implemented without issue. The Empire representatives emphasized the importance of a diverse fuel supply and talked about new weatherization technology that is now being included in new wind farms. The Empire representatives also discussed the reliability that dual fuel units (natural gas/fuel oil) provide. The Empire representatives suggested looking at investments in generation resources, looking for multiple ways to deliver fuel, and looking at market products to encourage investment in reliability. The Empire representatives explained that having conversations and collaboration with neighbors was a huge benefit to the system. The Empire representatives explained that there was opportunity to look at scaled up communication platforms to serve their majority rural footprint.

The Empire representatives were asked whether wind generation is typically weatherized. The Empire representatives explained that newer wind farms tend to have a cold weather package available and that utilities have been taking advantage of them. The representatives weren't sure about the ability to retrofit older facilities with cold weather packages. The wind delivered to the Empire system met their forecast.

The Empire representatives were asked what they meant about investment signal language. The Empire representatives explained that historically the marginal price to bid into the market is extremely low. When you need additional resources, the right kind of investment signals are needed. High prices send the message that additional generation is needed. The Empire representatives suggested that the RTOs could create market products that incentivize reliability on the system.

The Empire representatives were asked whether the MISO and SPP would be the entities to direct the market products or if that would be under someone else's purview. The Empire representatives indicated that it would be most effective if the RTOs create the market products to send the right investment signals to the utilities.

The Empire representatives were asked what kind of fuels need to be looked at for baseload. The Empire representatives responded that a diverse fuel supply is needed. They explained that there has been a transition to natural gas, but that you have to manage the reliability of not having an onsite fuel supply. They suggested storage, liquefied natural gas, winterization, and dual fuel systems could help. The Empire representatives explained that they had coal plants that tripped offline, low gas pressure issues, and wind farms with frozen turbines. They recommended having a diverse fuel supply to be able to navigate reliability.

The Empire representatives were asked if they were referring to a dual fuel unit as powered by natural gas and fuel oil. The Empire representatives responded that it doesn't exclusively have to be that configuration. They explained that there is a benefit to being able to use multiple fuels, especially fuels that can be kept on site.

The Empire representatives were asked about other examples of onsite dual fuel. The Empire representatives explained that they were looking at a variety of resources, including over-firing with hydrogen, battery storage, and propane.

The Empire representatives were asked how to define reliability-based products. The Empire representatives explained that SPP manages what they need on the system to create market products. SPP has locational marketing prices and ramping prices to compensate for system needs. Market products incentivize what kind of generation is built.

The Empire representatives were asked if creating market products was the role of the RTO, which they confirmed.

7. **Summary of Testimony from Donald Rowlett, Managing Director of Regulatory Affairs** — **Oklahoma Gas and Electric (OG&E) and OGE Energy Corp.**

Mr. Rowlett explained that the challenge of the February 2021 winter event was two fold: 1) maintaining generation to prevent uncontrolled outages and 2) protecting the ability to procure fuel in light of a high cost-constrained natural gas supply.

Mr. Rowlett explained that Oklahoma Gas and Electric focused on keeping generation online and when curtailment was needed they performed controlled outages that were limited in scope and duration. He emphasized that they served 99% of hours overall. Mr. Rowlett explained that the OG&E's goal was to minimize service disruptions and give advanced notice when possible.

Mr. Rowlett discussed the use of Emergency Alert levels during the event. Mr. Rowlett explained that OG&E passes fuel costs directly to customers with no markup. He expressed gratitude to the Arkansas legislature for the securitization bill they passed that allowed them to spread the cost to customers out over 10 years.

Mr. Rowlett was asked to describe the diversity of their fuel supply. Mr. Rowlett explained that OG&E has 7200 MW of generation capability, 1800 MW of which is coal. Mr. Rowlett explained that they had recently converted 1000 MW of coal-fired generation to natural gas and installed scrubbers on the remaining coal units. This strategy allowed them to comply with Regional Haze Rule requirements while maintaining fuel diversity. Mr. Rowlett also mentioned that OG&E had purchased two combined cycle plants that were originally built as merchant plants in the early 2000s. Mr. Rowlett explained that lessons learned during a weather event in 2011 helped them because after that event, they started putting protective measures in place to weatherize units. Mr. Rowlett mentioned that OG&E also has a small amount of solar, but the biggest resources in their mix are wind, natural gas, and coal.

Mr. Rowlett was asked whether combined cycle units were dual fuel. Mr. Rowlett responded that the combined cycle units they operate are not. Mr. Rowlett explained that combined cycle uses two methods to get energy out of natural gas: combustion turbine and a steam boiler heated with exhaust gas.

Mr. Rowlett was asked whether OG&E sells on the grid. Mr. Rowlett explained that OG&E sells all of its generation into the integrated market and all customers' needs are purchased out of the market.

Mr. Rowlett was asked what he sees as the best fuel for baseload generation. Mr. Rowlett explained that he still thinks that natural gas is the best fuel given the environmental concerns with coal. Mr. Rowlett suggested considering dual fuel capability.

Mr. Rowlett was asked about the scrubbers put on 2 of their coal units. Mr. Rowlett explained that they put scrubbers on both units for about $490 million.

Mr. Rowlett was asked what part of their generation is satisfied with baseload. Mr. Rowlett explained that 60% of their units were designed for baseload, but on any given day they may see 70% provided by wind. Their baseload units aren't operating like a baseload unit based on the way units are dispatched.

Mr. Rowlett was asked what percentage of electricity needs should come from a reliable baseload type fuel. Mr. Rowlett explained that intermittent resources are credited for less than their actual capacity. You need total credited capacity to meet peak. Mr. Rowlett explained that dispatching resources are typically fossil fuels. He also stated that solar, with its higher capacity factor than wind, is also a good resource. Mr. Rowlett also mentioned that solar wasn't very helpful during the February 2021 event due to the cloud cover.

Mr. Rowlett was asked whether he had any recommendations or best practices around notifications. Mr. Rowlett suggested that communication in as many ways as possible: traditional press, social media, text messages, etc. was beneficial. He also suggested that some people may need additional help understanding what is being asked.

8. **Summary of Testimony from Bradley Hardin, Manager-Government Affairs** — **Southwestern Electric Power Company**

Mr. Hardin provided an overview of the area the utility serves and their generating assets in Arkansas. Mr. Hardin explained that SWEPCO has diversity in fuel sources and location of generation assets to address local and system-wide needs. All of SWEPCO's generation assets are within the SPP RTO. Mr. Hardin described the appeal for conservation and described their outreach via news releases, social media, text messaging, and communicating with local government about controlled interruptions. SWEPCO had two limited controlled interruptions during the event.

Mr. Hardin was asked whether most customers that experienced a brief outage had notice. He was also asked if he heard any concerns from customers who were not aware. Mr. Hardin mentioned that he knew of one commercial customer he interacted with who felt that he didn't have adequate notice.

Mr. Hardin was asked what adequate notification looks like. Mr. Hardin explained that SWEPCO and others need to add to a proactive communication list. He explained that, at the same time, they did issue a press release to the news media, made extensive use of social media, and used all of the available tools to make sure the word was spread.

Mr. Hardin was asked about the coal plant in southern Arkansas. Mr. Hardin explained that the Turk facility operated by SWEPCO came online in 2012 and is one of the most efficient, cleanest coal units in the United States.

Mr. Hardin was asked about coal freezing. Mr. Hardin explained that typically coal plants keep a 30-day supply at full load volume on the ground at the plant. The coal is moved with large tractor equipment. The coal has moisture content, which is even higher than lignite. It can freeze.

Mr. Hardin was asked about what he sees as the best fuel for baseload generation. Mr. Hardin responded that natural gas is the best fuel for baseload generation for cost and environmental reasons.

Mr. Hardin was asked how Arkansas plays a part when well freezes prevented natural gas from coming into the state. Mr. Hardin suggested that additional weatherization is warranted to ensure there is no freezing or locking up.

Mr. Hardin was asked who was responsible for weatherization of the natural gas system. Mr. Hardin explained that it was the producers.

Mr. Hardin was asked if it was his understanding that RTOs were responsible for directing efforts towards the mix, which Mr. Hardin confirmed.

Mr. Hardin was asked about whether the City of Bentonville was notified of pending fuel surcharge increases before they happened. Mr. Hardin responded that they were advised ahead of time that increased costs were possible; but, SWEPCO couldn't quantify the increases at the time.

9. Summary of Testimony from Andrew Lachowsky, Vice President of Planning and Operations — Arkansas Electric Cooperative Corporation

Mr. Lachowsky explained that electric generation planners use a "no more than one day of outage in ten years" as a reliability goal. Mr. Lachowsky pointed out that the zero degree weather affected coal, gas, and wind resources and that natural gas was not available. He noted that during the event, AECC became a winter-peaking utility with 51 hours during the event exceeding their all-time summer peak.

Mr. Lachowsky explained that there are no easy solutions and that a single utility cannot act unilaterally to ensure reliability. Mr. Lachowsky explained that actions needed to ensure reliability must be region-wide and that SPP and MISO are working with stakeholders on this. Mr. Lachowsky stated that wind and solar are valuable energy resources, but there are times when they don't produce well. Mr. Lachowsky also provided that four-hour energy storage using current battery technology is also not the answer. Mr. Lachowsky talked about the increased cost and permitting associated with burning fuel oil. Mr. Lachowsky expressed the hope that any new natural gas facility replacing White Bluff and Independence will include the ability to burn fuel oil.

Mr. Lachowsky was asked whether RTOs or the Task Force should include storage as part of an overall investment should we encounter another weather event. Mr. Lachowsky explained that Enable is evaluating additional ties into another natural gas pipeline. Mr. Lachowsky stated that tie-ins to significant natural gas storage don't exist in the Oklahoma area. Mr. Lachowsky suggested that having a robust system for both natural gas and electricity transmission would be valuable.

Mr. Lachowsky was asked what strategies are being looked at. Mr. Lachowski talked about the value of a diverse mix. For example, droughts can impact hydropower and steam plants. Solar is helpful in the summer.

Mr. Lachowsky was asked what the best fuel for baseload generation is. Mr. Lachowsky stated that natural gas is the best fuel for baseload generation based on economics and availability.

Mr. Lachowsky was asked what the second fuel in a dual fuel system was. Mr. Lachowsky stated it could be diesel or fuel oil.

Mr. Lachowsky was asked if he was aware if anyone had used propane for replacement generation. Mr. Lachowsky stated he was not aware if it was being used for that.

Mr. Lachowsky was asked what the RTO's motivation was: to make decisions based on reliability of fuel versus economics versus political decisions. Mr. Lachowsky explained that AECC participates in both SPP and MISO. The two RTOs act differently. On the MISO-side, they have a capacity market that has been clearing at zero and signaling that capacity is free. They are looking into making changes so that no entity can lean exclusively on the capacity auction. SPP does what the members want them to do. SPP doesn't tell you what you have to bring to the mix, just that you have to bring a certain amount of generation resources to meet needs.

Mr. Lachowsky was asked why most of the generating units being built are alternatives, but when asked, the utilities say the best baseload generation is natural gas. Mr. Lachowsky described changes SPP and MISO are making to examine how solar and wind perform each season instead of just summer peak.

Mr. Lachowsky was asked who AECC would be looking to on permits for additional fuels. Mr. Lachowsky indicated that they would be looking to DEQ.

Mr. Lachowsky was asked whether he had any comments on notification best practices and challenges. Mr. Lachowsky explained that each of the 17 co-ops made appeals to conserve and that each does it differently. Mr. Lachowsky stated that they alerted their 8 large interruptible customers about pricing and that they may be curtailed.

Recess Resumed at 3:04 PM

10. Summary of Testimony from Laura Landreaux, President and Chief Executive Officer and John Bethel, Director of **Entergy Arkansas, LLC**

Ms. Landreaux explained that the extreme weather event presented challenges for Entergy at many levels and that the system performed well with outages that were limited in both amount and duration. Ms. Landreaux explained that a variety of notifications were used to request customer conservation to address the supply/demand imbalance including calls, text messages, broadcast, and social media.

Ms. Landreaux emphasized use of a diverse set of generation resources to provide safe and reliable electricity at a reasonable rate. Ms. Landreaux explained that Entergy is the largest transmission owner in Arkansas and that transmission investments have strengthened the system. Ms. Landreaux stated that Entergy continues to invest in modernizing the system, including investments in advanced meters.

Ms. Landreaux described the historically high demand during the February 2021 weather event and that having high usage and demand during the winter creates additional challenges because there is competition for natural gas for both heating and other direct uses. At the direction of MISO, Entergy conducted rolling intermittent outages of short duration. Ms. Landreaux explained that Entergy continues to evaluate experiences and explore opportunities to improve preparedness, operations, and communication.

The Entergy representatives were asked how having nuclear baseload benefited them and how winter events might affect investment strategies going forward. Ms. Landreaux talked about Entergy's emphasis on diversification. The investment in Nuclear One has served them very well. They received a license extension to operate between 2034 and 2038. Ms. Landreaux explained that they will continue to evaluate and do maintenance to keep Nuclear One in good shape so they can seek another license extension when the time comes. Ms. Landreaux noted that the units performed exceptionally well with one unit having a concern caused by transmission issues. She noted that in 2020, 70% of Arkansas customers were served with nuclear energy.

The Entergy representatives were asked what they see as the future to maintain and continue the workforce to maintain reliability. Ms. Landreaux stated that Entergy recognizes that the workforce training/development issue is real. She described investments that Entergy has made in partnering with technical colleges and the Department of Education.

The Entergy representatives were asked if there was currently any appetite to explore more nuclear energy. Ms. Landreaux stated that the Nuclear One has served Arkansas very well and that nuclear is a great resource. They continue to look at whether new nuclear can be cost-effective going forward.

The Entergy representatives were asked what part regulation may play in making new nuclear cost prohibitive. Ms. Landreaux explained that there are a lot of significant costs for equipment, startup and infrastructure. She doesn't believe the regulatory side costs are comparable to those upfront investments.

The Entergy representatives were asked about the planned obsolescence of Independence and White Bluff. They were asked if they would maintain them for standby or backup. Ms. Landreaux explained that maintaining them would require investment in controls. She stated that these units are at the end of their life and dollars would be better spent in investing in new technologies that would provide a better benefit to customers.

The Entergy representatives were asked about what type of replacement capacity they were looking at. Mr. Bethel responded that diversity is critical and that there will continue to be a mix of resources, including nuclear and gas. They are also looking at natural gas co-fired with hydrogen and are investing in solar. Mr. Bethel said Entergy will continue to have a mix of generating resources, both baseload and renewables.

The Entergy representatives were asked about what percentage of generating capacity can be from renewable sources of energy with current transmission capacity from a reliability standpoint. At what point would we need to invest a good deal more in transmission? Mr. Bethel responded that Entergy plans to become net zero carbon by 2050, but that this goal is not the same as having 100% of capacity as renewable energy. Mr. Bethel said that energy resource planners would be more capable of answering questions about the capability of the transmission grid.

The Entergy representatives were asked how much load in 10 years will be served by wind. The Entergy representatives responded that they have issued a request for renewable resources, including wind. They indicated that wind resources in Arkansas are limited, so there is additional cost to bring wind into the system here. They will continue to evaluate whether diversification outweighs cost. Entergy doesn't currently have wind in its mix.

The Entergy representatives were asked whether extreme weather affects transmission lines. The Entergy representatives indicated that it could, but that neither of the Entergy representatives present could elaborate on how.

The Entergy representatives were asked whether there is something Entergy is looking into to improve notice to customers about the nature of outages. For example, some customers got notice 45 minutes into one of the rolling outages and weren't sure whether this was curtailment or if there was damage knocking out power to their homes. The Entergy representatives explained that the timeframe that they learned that MISO was calling for curtailment and when the first curtailment took place was very short. They had a list of circuits to turn off and then back on. They indicated that there is room to be able to identify the customers served on each of the circuits and better direct communication about who is next to experience outages.

The Entergy representatives were asked whether they had any recommendations on how the state could assist companies with notifications. The Entergy representatives stated that using social media messaging would be helpful because they may have a different audience than the state has. They also indicated that sharing on different outlets is a helpful, useful tool. They stated that communication to customers is top of mind to Entergy.

11. Summary of Testimony from Randy Eminger, Executive Network, and Michael Nasi, Attorney Energy Policy Network (EPN) and Jackson Walker Law Firm

Mr. Eminger stated that a lot of attention has been put around the weather, but that what started five years ago is being left out. Mr. Eminger pointed out that in MISO, 45 baseload power plants (coal, nuclear, and gas) have been closed. In MISO, 15 baseload power plants have closed. Mr. Eminger stated that the RTOs closed these and that he believes that, if these power plants had been online during the February 2021 winter event, MISO and SPP wouldn't have experienced power shortages like what were experienced during the event. Mr. Eminger indicated that these closures are driven in part by price, but also through policies of certain states. Mr. Eminger stated that Arkansas should be concerned when policies in other states are affecting Arkansas.

Mr. Nasi explained that the power shortages in Arkansas are minor by comparison to what happened in Texas. Mr. Nasi discussed the changes in Texas' fleet and what has happened in ERCOT. Mr. Nasi stated that there were great similarities in terms of what has happened in Texas and where things might be going in SPP and MISO.

Mr. Nasi warned that we were four minutes from the most epic energy disaster in the country. He stated that he has been involved in advocacy efforts to wake Texas up to the shortcomings of their energy market design. Mr. Nasi stated that to understand what happened in Texas you have to look at their installed capacity with one third of capacity being intermittent and baseload shutdowns over the past five years. He stated that the big story of the February 2021 event was natural gas supply with finger pointing about electricity lost at the wellhead and gas not being ready for winter.

Mr. Nasi said that he advocates on behalf of every fuel source and that they all have great attributes and downsides. Mr. Nasi stated that a just-in-time dependent fleet is a risky fleet and that having gas as the sole dispatching resource is risky. He said that no one wants to talk about the fuel security that coal and nuclear provide. He indicated that coal freezing in a train was the problem, not frozen coal piles at plants. He stated that the February 2021 winter event is a story about how great coal and nuclear are. Mr. Nasi spoke of the need for comprehensive market reforms in Texas, such as creating a seasonal operating reserve as a new product on the ERCOT market and fuel storage requirements.

Mr. Nasi recommended prevention of decisions being driven by perceived obsolescence. He stated that units can be retrofitted with environmental controls, which is a big investment. He said that coal plants that have made those investments have been happy with it. He suggested that if the coal plants that retired recently were available, the shortages in Texas would have been limited to about three hours. Mr. Nasi said that this doesn't make gas a bad fuel. However, he stated that having gas as the sole dispatching component of a system is dangerous. He is concerned that Arkansas, MISO, and SPP are moving in that direction.

Mr. Nasi highlighted a finding in a MISO report that significant disruption is expected once you get past 30% intermittent resources based on the current transmission grid. He stated that Texas' experience during the February 2021 event is not an accident given that they have 33% intermittent energy capacity.

Mr. Nasi recommended that the state stand up within its role in SPP and MISO. He stated that state policies must be absorbed into RTO market rules. He suggested passing reliability standards and being weary of retirements. He stated that coal plants can comply with environmental law if you invest in them. He recommended that Arkansas take a very jaundiced view of any retirements in the wake of the February 2021 winter event.

The representatives of EPN and Jackson Walker were asked if they see storage for natural gas as a key part of pricing for RTOs. Mr. Nasi answered affirmatively and talked about the large portion of the fleet that is served by natural gas and that it is the best technology we have for a quick start. He said that gas storage is all about siting and economics. He suggested that siting criteria should factor in gas storage capabilities. Mr. Nasi stated that super low gas prices have a lot to do with the lack of investment in gas storage capabilities. He emphasized the need for better price signals for thermal generation to bring about more favorable economics. He stated that he is bullish on storage, but skeptical about it being a meaningful part of the bulk electric system.

The representatives of EPN and Jackson Walker were asked if there was a sweet spot for intermittent resources. Mr. Nasi stated that battery storage would allow intermittent energy to be more functional. He mentioned price spikes happening in colder months when solar and wind did not generate as much as forecast.

The representatives of EPN and Jackson Walker were asked about where incentives to keep existing baseload remaining in operational reserve would come from. Mr. Nasi responded that it would be highly dependent on state policy and market rule of the grid. Markets could better value market reserves and states could create incentives for reliability, carbon capture, etc. Mr. Nasi said the state of Arkansas can advocate in its role within MISO and SPP for better valuation of winter fuel secure resources. Mr. Nasi also described the concept of firming where new intermittent resources must have thermal backup. Mr. Nasi also discussed his efforts to keep coal plants open. He stated that once the capacity is gone, it is gone forever. Mr. Nasi stated that he was a firm believer that environmental controls are a good investment.

The representatives of EPN and Jackson Walker were asked who would contract for intermittent capacity tied to baseload capacity. Mr. Nasi stated that there is already an ancillary services product in the market. He described the different ways that renewables and thermal generation participate in the market. He suggested that there could be a balancing that requires the intermittent resource generator to have dispatching back up through battery, contract, or with the RTO.

The representatives of EPN and Jackson Walker were asked if they would define baseload as on call fuels. Mr. Nasi stated that we are in good shape in Arkansas right now, but that MISO and SPP are heading in a direction that will look like ERCOT driven by tax policy for wind and solar and state policies. Mr. Nasi suggested that states pass policies that prioritize dispatching and ensure reliability. Mr. Nasi stated that future building plans in MISO and SPP look scary.

The representatives of EPN and Jackson Walker were asked how to bring about Mr. Nasi's recommendations when different states have different processes. Mr. Nasi stated this is a difficult nut to crack because each state sets policies based on their values.

12. Summary of Testimony from John Peiserich, Attorney **PPGMR, LLC**

Mr. Peiserich explained that his comments are his own and do not reflect his clients. Mr. Peiserich suggested that Arkansas adopt a similar statute to the Texas Disaster Act of 1975 to relieve electric generation facilities and other industrials of certain obligations under environmental rules if the Governor issues an executive order that a disaster has occurred or is imminent. The period of regulatory relief would only continue as long as the disaster is ongoing, but no longer than thirty days. Mr. Peiserich indicated that the relief could come in the form of time extensions on compliance or waiver of emissions control requirements or continuous emissions monitoring requirements until the emergency passes before making a repair instead of shutting down the unit immediately. Mr. Peiserich explained that Texas invoked this act during the February 2021 winter weather event and that it allowed suspension of 15 chapters of TCEQ rules to provide flexibility needed to respond to the event.

Mr. Peiserich was asked about his opinion regarding how baseload generation should be looked at. Mr. Peiserich responded that we have to have a fuel mix. In his position, he doesn't have to worry about economics. He stated that natural gas is clearly best from an economics perspective. He indicated that the bigger issue is that we have other types of generation (hydro and nuclear) that would provide tremendous benefits across the board, but they are almost impossible to permit. He explained that it may take 10 – 15 years to permit a nuclear facility.

13. Closing Remarks **Secretary Keogh**

Secretary Keogh concluded the hearing at 4:14 pm.

ENERGY RESOURCES PLANNING TASK FORCE

ORIGINAL

PUBLIC HEARING

JUNE 1, 2021

BEFORE:

BECKY KEOGH, CHAIRMAN AND SECRETARY OF THE ARKANSAS DEPARTMENT OF ENERGY AND ENVIRONMENTAL QUALITY

MICHAEL PRESTON, SECRETARY OF COMMERCE AND EXECUTIVE DIRECTOR OF THE AEDC

LARRY BENGAL, DIRECTOR OF THE ARKANSAS OIL AND GAS COMMISSION

KEVIN PFALSER, DIRECTOR OF THE ARKANSAS LIQUIFIED PETROLEUM AND GAS BOARD

STEVEN SPARKS, DIRECTOR OF THE AEDC, EXISTING BUSINESS RESOURCES DIVISION

TAKEN BEFORE Karisa J. Ekenseair, Certified Court Reporter, LS Certificate No. 802, Bushman Court Reporting, 620 West Third Street, Suite 302, Little Rock, Arkansas 72201 on June 1, 2021 at the Arkansas Department of Energy & Environmental Quality, 5301 Northshore Drive, North Little Rock, Arkansas commencing at 10:00 a.m.

T A B L E   O F   C O N T E N T S

SECRETARY KEOGH: Good morning to all of you that have come this morning after a Memorial Day holiday weekend. We thank you for taking the effort to be here this morning to participate in the Energy Resources Planning Executive Task Force commissioned by Governor Asa Hutchison.

Today is June 1st, 2021, and we are here present at the Arkansas Department of Energy Environmental Headquarters to hear testimony for the Energy Resources Planning Task Force. This is actually the second day of hearings. We had a -- hosted a hearing last week and we can speak to that, as needed.

Just by introductions, I am Becky Keogh, Secretary of the Arkansas Department of Energy and Environment. And I have the pleasure of serving on this task force with Secretary of Commerce, Mike Preston to my right; Director of the Oil and Gas Commission Larry Bengal to my left; and Kevin Pfalser, Director of the Liquified Petroleum and Gas Board to my far right.

And we appreciate Secretary Preston, the participation of Director Sparks who joined us last week for the first day of hearings who was the Director of the AEDC Existing Business Resources

Division.

We also have a number of staff that are supporting these hearings as well as the development of a report that will go to the governor. Staff today, if you have any questions, if you're here, we have Troy Deal and Beth Thompson in the back of the room, as well as Morgan Acuff, I believe, outside. Andrea Hopkins up front here.

We have two folks taking notes, Tricia Treece and Dan Pilkington who are helping us prepare the report. But the staff are all supporting -- all the department staff are supporting in efforts.

On March 3rd -- and I'll introduce my communications director, Donnally Davis, who has also been key to making this all go forward. And then our chief counsel, Shane -- Shane Khoury in the back who is also supporting our initiative.

On March 3rd, 2021, Governor Asa Hutchinson signed Executive Order 21-05 to establish an Energy Resource Planning Task Force. And the purpose of this hearing today is to gather information from testimony in order to better prepare our state infrastructure in the event of another statewide emergency, which we all hope not to have. But we know it's best to be prepared and plan for.

We've had a number of 100-year events, as I mentioned earlier in some conversation: A flood, and then followed by the pandemic, plus the ice storm. So we know too well in this administration that preparedness is important for the state, not only for our administration of state services, but to our citizens and to make sure that we are planning, especially as our environment changes and certain -- particularly in our energy sector. The energy sector is in such a dynamic state of change, we want to make sure that all that is done effectively.

I'll take a personal moment in opening. I wanted to mention that during the holidays, I know that we do have a number of people present. But we also have some folks joining us by Zoom, I believe, this afternoon from some of the electric utilities. I believe today we have, this morning, everyone here is present.

But we also are -- those of you that speak, we are also live-streaming as many of the state board commissions and events, such as legislative committees are. So this is being live-streamed and we appreciate the service of Arkansas PBS, the ARCAN station, so -- it can -- it is being taped for future reference, should you desire.

I'll say hi to my granddaughter, who may be live-streaming this morning, as I was giving her the information as she's here today visiting for the holiday weekend and extended, so appreciate that. Anyway, so I'll say hi to Isabelle and tell her to pay attention.

She lives in Houston so she actually had more extreme effects at her home than Arkansas did, as you know, as they lost power and water for a number of days during the storm. They're positioned in.

So just with that, I'll move forward. As chair of this task force, I will call the names of organizations that will provide testimony today. And when your organization is called, I will ask you to just come forward to the podium or, I guess the table -- I think we have a table set up over here for your convenience.

There is a mic. And the way the mic works is you push the button. And if you see the lime green, you're on. And if it's a nice forest green, you're off. So make sure you're bright, turned on, as it is difficult, from what -- our understanding, to hear. We may be able to hear you up here, but I believe there was some difficulty hearing some of our speakers at the last hearing, particularly on the live-stream, so we want to make sure everyone can hear your words.

We ask that testimony be limited to five minutes per organization that's presenting this morning. If you have multiple folks that come to the table, that's fine. Just we ask you to collectively use that five minutes appropriately.

And then after that opening statement, if you will, if you have one, I'll ask -- and open the floor to the task force members to be able to ask questions if they have follow-up questions. I know they've done their homework and studied prefiled testimony that many of you submitted to us, background and perspective. And so we want to build on that, again, trying to fill in any information we need as we go forward.

We hope that we'll be able to gather this during these hearings. There could be potential follow-up later based on something we hear in another hearing, but we'd like to make sure that we are being efficient with your time as well ours and getting these recommendations well thought through, but also presented in a timely fashion.

So we've allotted about 15 minutes, as I mentioned, for that quick Q&A portion of the hearing for each of you. And I know Andrea Hopkins has the pleasure of being our timekeeper for the hearing. She'll be gracious, but she will be present, if you start extending your time. We'll ask you to be respectful of these time limits to that extent so that our hearings will conclude appropriately.

So the first speaker this morning we will ask to testify is Black Hills Energy. I know we have several representatives here, and I'll ask you as you step forward -- I'll mention as you come forward -- we'll be asking CenterPoint Energy to come forward next. So with that, just give you a little bit of time to prepare.

So if you'll just -- again, if you'll state your name, your title -- your title and your organization for the record and for the benefit of those listening today. Appreciate that.

CHAD KINSLEY: Good morning.

SECRETARY KEOGH: Good morning.

CHAD KINSLEY: Members of the Task Force, I'm -- thank you for the opportunity to be here with you today to discuss this important topic. I'm Chad Kinsley, Vice President of Operations for Black Hills Energy. And with me today is my colleague, David

Brink, our senior manager of gas supply.

The first handout that I gave you just gives you a high-level overview of who we are as a company. Black Hills is proud to serve nearly 1.3 million natural gas and electric customers across eight states.

And the page, in Arkansas, specifically, we're a local gas distribution company that serves more than 178,000 customers across 100 communities and 19 counties in Arkansas.

And all of us are familiar with the February of extreme weather conditions that descended upon a large section of the country. For context, Northwest Arkansas reached near-record-low temperatures approaching 20 degrees below 0. And our system experienced a new system peak day of 130 -- I'm sorry, 311 million cubic feet delivered, which exceeded our prior peak day by more than 10 percent.

Across the state, our technicians bundled up and worked tirelessly to ensure gas kept flowing reliably to our customers. Overall, the investments in our team and our system enabled us to successfully meet the extraordinary demand for natural gas.

Beginning February 10th, based on these below-normal forecasted temperatures for a prolonged period, we began encouraging customers to conserve energy. We aggressively shared this message with our customers and stakeholders, using channels such as direct communication, broadcast media, social media, and our website.

As temperatures continued to plunge and demand surged, we redoubled our outreach to customers and the public to conserve. Our team began directly contacting large-volume customers, advising them to prepare to curtail their usage.

By February 16th, the interstate pipeline delivering gas to our system issued an emergency response operational flow order requiring customers without Human Needs affidavits to curtail their usage. Black Hills Energy also received force majeure notices from our supplies due to insufficient upstream supply, production well freeze-offs, failure of compressor facilities, and other supply disruptions.

Then on -- beginning February 16th, we did lose service. This is the one place we lost service to our customers, in the community of Pea Ridge. We lost about 22,056 customers in the Pea Ridge area due to capacity constraints on our system.

This constraint is now being remedied by an

Arkansas Public Service Commission-approved pipeline project that will provide sufficient capacity to the Pea Ridge area for many years to come. Overall, though, our team and our system performed very well during this historic event.

As a requirement and sound business practice, every year we develop a natural gas supply strategy, which is filed with the Public Service Commission. Our storage assets in the River Valley are an important part of this gas supply strategy and help reduce the exposure to dramatic commodity cost increases and failures of the interstate gas supplies.

Looking forward, it's important for Arkansas to continue to provide support in policy and regulatory environments that encourage development of Arkansas energy resources, including natural gas production, storage pipeline, and renewable gas facilities.

Black Hills will continue to evaluate prudent investments that would further improve the reliability and reduce exposure to dramatic increases in natural gas prices or failure of the interstate gas supplies.

Also in the future, if electric utilities find it necessary to implement rolling blackouts during extreme events, we'd encourage close coordination with gas utilities to the extent possible, since upon power restoration, there can be an increased surge in natural gas demand due to nearly all the affected loads coming on concurrently, which could result in even further strain on the gas distribution system.

In addition to continuing to help our customers find ways to conserve energy, we're dedicated to helping customers in need of assistance. Our customer service representatives worked extended hours and were well prepared to provide guidance and support.

Black Hills Energy has already begun sharing additional communications to customers so that those in need of financial assistance are aware of all the options.

Again, we appreciate your interest and your time this morning on this important topic. Black Hills Energy, along with other jurisdictional utilities, are also participating in a Public Service Commission investigation docket also related to the winter event and will remain committed to working together as we move forward.

Thank you, and look forward to answering any questions you may have.

SECRETARY KEOGH: Thank you for being present. Did you have additional comments that you'd like to make?

Well, thank you so much. And we did, in our first hearing, hear from Public Service Commission Chairman Thomas, as well as representatives of the Attorney General's Office. I know they're -- they also have ongoing review of the -- of what occurred under their authority, so they are compelled to conduct during an event like that.

So I guess differentiator for this hearing, we believe, and the purpose the governor set forth is approach of looking at lessons learned and resource planning for our future as a state. And so we hope that this conversation sets the tone of how we continuously improve what we do and how do we respond to changing conditions and be better prepared.

So with that, I know you mentioned that notification was important, and it sounds like you conducted a number of notifications.

And I guess I would just question, if there -- I know your commercial customers or business customers might have been more directly affected by the cutoff or curtailment, is there a process that y'all use to -- I know you described the curtailment process, but did you have any customers, specifically that kind of got caught off guard, and they had not filed affidavits? Or is there a way that we can enhance that process to make sure that when the unfortunate events occur, that they are prepared to make their contingency plans or whatever adjustments that might prevent costly damage to their equipment or perhaps even more in tragic situations?

CHAD KINSLEY: Sure. I would say, certainly, I think there's opportunity to improve that process. Black Hills hadn't had to curtail a customer probably for about 25 years. We looked back. So that process was fairly stagnant, frankly. So I think there is opportunity to improve that process.

We started on February 10th with broadcast media, asking customers, making them aware to start thinking about conserving energy because of the forecasted temperatures and forecasted demand. And then -- and that was on a Wednesday.

By Saturday, we had started reaching out directly. Our business development team, who manages our key accounts, started reaching out directly to our large-volume customers, beginning to inform them that they would potentially need to be curtailed or to ask if they could start to reduce their usage.

And we continued those direct communications with our large-volume customers throughout the event. But there certainly is opportunity to probably improve that process and help educate, frankly, our customers and transport customers who buy their gas from other suppliers on the process overall.

SECRETARY KEOGH: Thank you. And any specific recommendations as you evaluate these processes, please feel free to share those with us so that we can incorporate them in our report that we will be providing to the governor following the hearings.

And I believe we'll be preparing that this summer with the concept of a draft being available, hopefully in early August, so that even those of you that are participating can offer additional information that you may have learned.

So with that, I'm going to turn now to the, I guess, Secretary Preston, if you have a question. Then we'll move across the board and come back for additional questions.

SECRETARY PRESTON: First of all, thank you. I appreciate y'all being here and coming down. I will say, your team's communications was real good throughout the process. I appreciate Charlie and his representation working with our team to make sure we have that flow of information, so I do appreciate that.

Has there been any follow-up with those who were curtailed in Pea Ridge on the business side of, hey, here's what happened? Has that been, you know, clearly communicated to them, this is what the process is going to look like going forward?

CHAD KINSLEY: Yeah. Specifically with the community of Pea Ridge we had similar communications through Charlie and others on our staff making the city leaders aware of the situation. Also took out newspaper ads, trying to make the community aware essentially.

So I'd say, yes. And it was very apparent. We've started building that pipeline already up to that community. So we've gotten questions through the community about that. Specifically to, you know, every individual, you know, residential customer, we haven't made communications specifically to every residential customer. But largely through the city and through newspaper ads, we have.

SECRETARY PRESTON: And I guess I'm just thinking from a perspective of recruitment and economic development working on industrial clients that we're trying to convince them to come to Arkansas.

How do we convince them that, hey, here's what happened in the past; here's how we can assure them it's not going to happen in the future. And I guess your point would be the new pipeline coming in would prevent in that area, but you know, for the rest of the supply area, what would we want to tell folks?

CHAD KINSLEY: Yeah. We would want to say that was a known issue. We knew that we were going to need additional capacity in the Pea Ridge area. We had projected it. We projected in our engineering department that we would need it by this coming winter. We just didn't use in 20-degree-below 0 temperatures.

So we're refining system models and we're always projecting and building our system, planning our system to meet the growth that is going to be needed, you know, essentially a decade to come, in that five to ten-year window, so.

SECRETARY PRESTON: Well, I appreciate it and I appreciate you guys always been great to work with on the economic development side as well. So it's very important to have that relationship in place. Thank you.

CHAD KINSLEY: Thank you.

SECRETARY KEOGH: Thank you. Secretary Preston, I will go next to your right to Director Pfalser if he has additional questions.

DIRECTOR PFALSER: I appreciate y'all coming down this morning. I know the weather wasn't great coming down from Fayetteville. I'm glad that you're here.

In your prefiled testimony, you referred to the federal government and possibly other local governments that are -- they're passing regulation that is opposed to natural gas. You know, for the last few years, it's been considered a green. I mean, it's always been associated with green. So why is there opposition to further development and use of natural gas for heating homes or generation of electricity?

CHAD KINSLEY: That's a great question, Director, one that, frankly, we don't understand.

And I think the natural gas industry is working to tell our story about how natural gas really has helped offset coal and other -- other more greenhouse gas emitters and really to help improve, you know, the greenhouse gas reduction across the country.

And so I think part of it is the lack of our industry needs to tell our story better.

DIRECTOR PFALSER: Gotcha. It's just been lumped in with all the fossil fuels, so there you go?

CHAD KINSLEY: Correct.

DIRECTOR PFALSER: Okay. We were talking earlier about the weatherization of equipment and how that really impacted the situation. And it's difficult when that equipment lies outside the state, for us to have an impact on that.

Can you all think of a way that this state could help, or what steps might be taken to ensure the -- even if you put in another line to Pea Ridge, for example, it wouldn't help them if those -- if the equipment was frozen and couldn't deliver.

So can you speak to how the State of Arkansas might participate or might help with the weatherization that's going on in Oklahoma or Texas or somewhere else?

CHAD KINSLEY: Yeah. I think a couple

ideas that I would offer would be looking at the supply side, you know, the Fayetteville shale, looking at developing Arkansas' energy resources. Are there opportunities there?

There's peaking facilities. Peaking is an important aspect of being able to cover your peak loads. And so if there's ways the state could, through the Oil and Gas Commission, or other entities could help study, are there storage facilities, you know, depleted hydrocarbon reservoirs, or you know, prior gas production? Could some of those facilities be -- be transitioned to natural gas storage?

So you can put the natural gas in the ground in the summer and withdraw it during peak loads in the winter. I think that would be -- be one area that we could explore further.

On the demand side, the state could certainly look at expanding energy-efficiency programs to both across industry and residential energy-efficiency programs to reduce or slow the demand growth for natural gas, which we're -- just helps balance the supply/demand equation.

DIRECTOR PFALSER: Okay. And we had -- and then just one last thing. We talked about some of the commercial -- Secretary Preston referred to the larger users.

At one time, it seemed like they all had some standby in the event that they had to be curtailed. And it seems that those have -- the storage has been sold into the LP gas industry.

You said it's been 25 years since you've had a curtailment or something like that. So are you seeing this, a lot of your large users no longer have the ability to provide fuel on-site for a period of time?

CHAD KINSLEY: Yeah. We have seen that diminish over time. I think the economics just haven't been there as natural gas prices have -- have reduced over this last decade. It's hard to justify that capital investment, or that ongoing operating expense for some of our large customers.

After this event, I will tell you -- and I go out and meet with some of our key accounts periodically, and that topic is coming up more. We see it not as much on the LP side, but more on diesel side, depending on -- on the industry, so to speak, where they may have a Number 2 diesel tank on-site for storage or back-up facilities.

DIRECTOR PFALSER: So some incentives for that particular purpose might help someone?

CHAD KINSLEY: Yeah. That might help some industries.

DIRECTOR PFALSER: Thank you.

SECRETARY KEOGH: Thank you, Director Pfalser. I'll turn to Director Bengal for follow-up questions.

DIRECTOR BENGAL: Thank you. Good presentation in your prefiled testimony. A lot of information there, covered it pretty well.

Looking at the map that you handed out of your service area, I see Arkansas is on the extreme southeastern part of your service area. I'm going to assume that the gas that serves Arkansas is coming from the Oklahoma, Texas area?

CHAD KINSLEY: That's correct.

DIRECTOR BENGAL: Because when you said you did not have a curtailment in 25 years, you said other service areas. I'm going to assume that the northern supply sources have weatherization in place that would have prevented that.

TOM STEPHENS: It's kind of hard to speak to that because most of the gas that we buy is from upstream suppliers and/or pipelines. I believe that the bulk of our, you know, supply does come from Texas, Oklahoma, that area.

DIRECTOR BENGAL: Even in your northern part of your service area?

TOM STEPHENS: Are you talking Arkansas or --

DIRECTOR BENGAL: No. I'm talking about Colorado, South Dakota.

TOM STEPHENS: Yeah. Colorado -- a lot of that would have, I believe. Of course, this event affected the midcontinent by and large the most. And so the bulk of that would be Texas, Oklahoma, that area. So you know, even Kansas territories, that sort of thing.

So typically, the further north you get, I believe you will see weatherization to a greater extent. It's just unusual for this type weather to, you know, dip this low and -- in the midcontinent.

DIRECTOR BENGAL: That weatherization be primarily an industry initiative?

TOM STEPHENS: I think that would probably be something that either the states or the producers will have to look at themselves. You know, a lot of its wellhead freeze-offs or, you know, is what we experienced or that's what we were, you know -- be a force majeure.

And so I think that would be more between the states and the producers to kind of come up with what's developed there for requirements.

DIRECTOR BENGAL: Are you aware of any state initiative that would incentivize that winterization that other states may use?

TOM STEPHENS: Not at this point. I think -- I think Charlie indicated that Texas was looking at a bill, but I don't know that there's any incentives in that to facilitate weatherization.

DIRECTOR BENGAL: What would that be, in Texas, they be looking at?

TOM STEPHENS: I think it was just looking at requiring some type of weatherization for that production, is my understanding.

DIRECTOR BENGAL: And you operate two storage fields here in Arkansas that you recently acquired.

TOM STEPHENS: We do.

DIRECTOR BENGAL: Do those fields come into play in the shortage that we experienced here? Were you able to withdraw gas from those fields?

CHAD KINSLEY: Yes. We do. As you alluded, we have two storage facilities in the Ozark area and they played a tremendous -- they were a tremendous asset for us during this event. We were pulling about 170 million cubic feet of gas out of those facilities a day, sending it largely north to Northwest, Arkansas. But they were -- were very important assets for us.

DIRECTOR BENGAL: I know you recently acquired those. You probably looked at other areas in Arkansas. Do you -- have you identified other areas that might support additional storage?

CHAD KINSLEY: We haven't looked at that. And that's one of the things I think where there is an opportunity to look at, you know, with -- there's the Fayetteville shale and into western Arkansas, the River Valley, if there are additional reservoirs that could be storage -- become storage facilities and help from a peaking perspective.

DIRECTOR BENGAL: Yeah. I know it's hard when you're limited in -- we heard some testimony last week. Some of the gas users would have liked to have been notified when the price was going to increase, as opposed to it just showing up.

Given they may be purchasing their gas not from that local supplier, but in bulk in a contract that is going through your system, is that a contractual -- how would that actually -- is that even feasible, for folks to be notified of a price increase that's going to occur in a very short period of time?

CHAD KINSLEY: Many of those folks that are -- there's two different types of customers. There's -- in the industry, they're called transport customers. And they're that entity, that company or end-user is buying their gas from a third-party supplier. So Black Hills, as the local distribution company, isn't privy or part of that transaction.

We're essentially a trucking company. We take the gas that they bought from a third party and deliver it to the -- their facility.

So that becomes more challenging, to help give them price signals in that type of contractual arrangement. They can certainly build that -- build that into their contracts with their suppliers to give them price signals. I would think there might be some opportunity there.

As a regulated utility, our prices are fixed. And so our price -- prices don't necessarily change except annually or when we make a special filing with the Commission, as we have with this event.

DIRECTOR BENGAL: Thank you.

SECRETARY KEOGH: I know our time has come to an end for this one, but I did have one follow-up question. I'll take Chairman privilege to do that.

Speaking to the cost question, I appreciate Director Bengal asking that question because I know there was some folks that might have chosen to reduce further their gas usage, had they had the opportunity maybe earlier in the process, anticipating that it might impact gas -- or cost ultimately on them.

But in the electric utility side, and I know y'all also operate utilities, you're probably familiar -- we talked about this as well, that there's interruptible tariffs that are established to kind of encourage customers that may have the ability to curtail quickly, a price advantage when they don't have -- so that, you know, they're kind of first off if we need to turn them off.

Is that feasible in the gas supply side of your business? Or is there a process that we could look at, or you perhaps as a gas provider or pipeline companies could look at to contractually establish that framework going forward?

CHAD KINSLEY: I would say it's something we could consider. Currently, Black Hills does not have interruptible gas tariffs, like -- so we would have to look at opportunities to do that. Much like on the electric side, it may require sending two meters because we would have to know which -- how to curtail their usage, which -- I think because most customers don't want to curtail all their usage. They want to retain some -- some level of gas usage for plant protection, for maintaining that so their plants don't freeze up and, et cetera.

So I think it's something we could look at. We don't have the mechanism currently to do that.

SECRETARY KEOGH: Thank you. And I appreciate that. That was just a concept that came up that was perhaps more uniquely used on the electric iteration side of the delivery side. I wasn't sure if it fit for gas providers.

With that, we appreciate your time this morning. Thank you so much. I think you have been very helpful responses to me, I know, and it appears to the other members. So I appreciate that.

We hopefully will -- like I said, have draft reports available and I'll look forward if we have any follow-up. With that, we'll ask you -- we'll end our time with you and we'll ask our representatives from CenterPoint Energy to come forward at this time, again providing title and organization as you introduce yourself. Thank you.

And to put the next speaker on notice, I believe it's the AIPRO organization if you'll want to come forward and make comments this morning.

MILES KENNY: We've got a presentation.

MR. DEAL: And the first screen is up on Zoom. They can see it on screen.

MILES KENNY: All right. Good morning, members of the Task Force. First, I want to thank you for the opportunity to give us the opportunity to talk about our experience from the February event.

My name is Miles Kenny. I'm the Vice President of Gas Supply. And with me today is Cindy Westcott, Vice President of Operations for Arkansas and Oklahoma territories.

We think about gas supply in my area of responsibility, you can think about taking supply from the market area and getting it to our distribution system. Slide 2, please.

And before we dive in, it's very --

SECRETARY KEOGH: Excuse me, I was reading the first slide. I apologize for interrupting. You had noted it wasn't for public disclosure. I just, for -- in full transparency, this is being live-streamed to the public. So if there's any sensitive information, I would ask that maybe you skip that slide quickly or if you feel uncomfortable -- I just don't want you to be in a situation that you're uncomfortable.

MILES KENNY: I think we're safe with everything that's on there.

SECRETARY KEOGH: Thank you. I just wanted to be respectful --

MILES KENNY: I appreciate that.

So the slide we're on should say we're not speculative gas traders. Is that the one that we're on?

Okay. Yeah. Before we dive in, I think it's extremely important to understand at some point we're not speculative energy traders. We're only purchasing gas for our customers' needs specifically. So again, just purchasing. Slide 3, please.

And this chart here represents the wide variety of managed scenarios that we see in Arkansas. Accordingly, we must have a supply portfolio that can provide reliable supply and price protection to our customers during all months, all weather scenarios, both warm and cold. Slide 4, please.

And our supply strategy is focused on a diversified portfolio with multiple supply products and pricing strategies. Depending on the level of demand, warm or cold will determine which supply products will be used to help balance reliability, reduce price volatility, and maintaining a reasonable price. Slide 5, please.

Here's a high-level visual of our monthly supply plan for this upcoming winter season. Again, showing the multiple supply products that will be utilized. Slide 6, please.

And this chart shows the supply products that were utilized to fully meet all of our supply obligations and keep our customers warm during this February storm. As you can see, our storage and asset management contracts that are based on summer pricing were able to cover 50 percent of our supply demand during that week.

Our call options based on monthly index prices covered 26 percent of our demand. And then 24 percent of our demand was covered with supply that was purchased in the daily market. Next slide, please.

And before I open it up to questions, I can't speak about the February storm without recognizing the tireless work of both our field and office employees during these extremely difficult times, and reiterate that CenterPoint was able to deliver all of our supply necessary to our human needs customers to stay warm during this unprecedented extreme weather event. And that concludes my prepared remarks. Thank you.

SECRETARY KEOGH: Thank you so much. That was very helpful to us and I know -- since it is marked I was asking counsel if we prefer that we hand these back to -- if you want them to remain confidential, I know it's been verbally communicated.

MILES KENNY: I think we're good. Thank you.

SECRETARY KEOGH: Whatever you prefer in that case.

MILES KENNY: You can keep it. Thank you.

SECRETARY KEOGH: Thank you. I appreciate CenterPoint's transparency today. And in your written statements, I know that you provided excellent information and some of the stresses. And I too want to acknowledge the work by many of the utility companies and their employees that -- and in getting fuel distributed in extreme difficult times.

And I know many trucks were on the road delivering. Exceptional effort made when it wasn't exactly safe to do so. So thank you for their efforts and their work to make sure Arkansans as well as other citizens across our region had the most available resources they possibly could.

Again, similar question I'd ask before: Do you have any recommendations on perhaps this whole scenario of needing fuel, but then also wanting to be cost sensitive so anything that can be done on the front-end in terms of your contracts or -- that would allow a customer to indicate preference to be curtailed if the cost exceeded a certain level? Or if there's a, you know, a hard line on minimum provided provision of gas that they need to avoid some kind of catastrophic damage.

I guess that's a different way to ask it, but I think that was the question I was asking earlier. Do you have any comments on that?

MILES KENNY: I do. So, you know, two things I'll point out: One being, if you took one from a supply perspective or one nugget that I think you should take away is a diversified portfolio.

So you know, again, I mentioned that all but, I think the number was 24 percent, of our portfolio was shielded from the high pressure -- high-priced daily market. And that's just because of the supply diversity. We have a lot of different products that fit into that portfolio.

And depending on which state and which region, there were different types of scenarios that happened. So not walking away thinking that storage is the silver bullet or that any other pricing product is. It's really around supply diversity. Pipeline and many upstream suppliers, the broader you can cast that net, the more opportunity you have for protecting your customers.

As far as for some of the customers that wanted to have an indication on price similarly to Black Hills, those are transport customers that have a separate supply and they would need to work that out in that standpoint. But it's really important that those transport customers understand the contracts they're under.

There's a lot of details that are separate from price. It can't be short-term; it's got to be long-term focused in understanding what are all those obligations that their suppliers have, but also what do those transport customers' obligations have. When you are curtailing down to human needs, what are the obligations of those customers that are not human needs customers, regardless of whether they're a CenterPoint customer or a transport customer.

And I think it's also worth noting that

when we went through our curtailment procedures, it was not a result of CenterPoint's system being on the brink. It was really an indication from upstream supplies, that in order to maintain the reliability of those upstream markets, we were doing curtailment downstream on our system to ensure that they -- we were able to maintain a broad reliability across the market.

SECRETARY KEOGH: Okay. I'll turn to Secretary Preston for any follow-up.

SECRETARY PRESTON: Thank you, Madame Chair. And I appreciate the testimony. And again, I'll just echo that CenterPoint's always been great to work with on the industrial side and the industry. And throughout the event of February of this year, y'all answered my phone call many times, as I was getting a lot of industrial calls. And y'all were kind enough to handle those calls. Maybe we didn't have the answer then, but we could at least talk through it so we could get the information back. So that was very helpful and I appreciate you and your team for doing that.

I guess, kind of what -- just kind of help me understand this: Is some of the feedback we were getting is it was getting to the point where it

looked like there might be a curtailment for some
certain industrial users. What I was getting was,
well, can we just have a limited supply to keep our
facility open, to keep machines from freezing up.
But as I kind of understood it more
throughout the process, it wasn't a matter of how
much gas supply you could use. It was either you had
gas or you didn't. Is that kind of how it goes? So
you guys can't really decide, all right, this
customer, you know, they could do without; but this
one has to have it for a reason? You guys aren't in
a position to make that decision, right?
MILES KENNY: Well, I think just to your
opening remarks, it's really around collaboration,
right. So we're not out to, you know, during times
like this, making sure we're maintaining human needs
but also not looking for catastrophic, you know,
equipment failure for industrial customers.
So just making sure what we're clearly able
to walk down that pass. But then, again, those
customers need to work with their upstream supplier.
If they're being curtailed and they don't have the
supply to get to that customer, they need to work
through that as well.
So it's a collaboration across all levels,

supplier back to the pipeline with the customer all being involved equally across, just making sure we're all on very clear expectations of what the demand would be so we can plan accordingly and make sure that no matter what, the nursing homes, residential or not, going to end up losing service because some customers were taking more than they're -- than what should have been during that curtailment process.

SECRETARY PRESTON: Has there been any thought or consideration going into next year? Hopefully, we're not in this situation like we were. Have a much calmer winter next year, but just planning going into that, to have those conversations prior to so we can kind of have a plan in place?

MILES KENNY: It's already happening. I mean, there's -- similar to this, there's a lot of conversations happening across all aspects, just around. I mean, some customers have said they want to leave transport, go back to sales just so they can be more in that structure group. But then there's a price -- there's a give and take on any one of those scenarios.

So all those conversations are happening, making sure that, you know, customers are looking at on-site backup. All those pieces are absolutely happening.

SECRETARY PRESTON: And I would just offer from the industrial side, if there is help that we can -- from my Department of Commence with the industrial side, let me know. Certainly we want to be a part of that conversation and be helpful if we can.

MILES KENNY: Thank you.

SECRETARY PRESTON: Thank you.

SECRETARY KEOGH: Likewise, from our Department of Energy, resources and planning, anything that we can do from a more wholistic standpoint, a more direct relationship than we do have -- I failed to recognize Mitchell Simpson in the back of the room, Arkansas Energy Office, here today as well. So we're appreciative of that.

With that, Director Pfalser, do you want to offer a follow-up question?

DIRECTOR PFALSER: Appreciate you all being here today. In your presentation, under supply products, you mentioned storage call options and then some peak shading with LNG or LP. Do y'all have some LNG?

MILES KENNY: In other areas of our overall footprint. We do not in this Arkansas region. Yes, sir.

DIRECTOR PFALSER: And that is been -- LNG, that doesn't seem like it would be very expensive storage option or a way to help with peak, is that you feel that's really a good asset to help?

MILES KENNY: You know, you've really got to take each scenario on its own and look at one, location of customers. Would a new supply source have an adverse effect on any of the customers in that region.

But also sometimes when you see an LNG scenario that works better than what you may have, a longer lateral and at the end, there may be some supply issues at the tail end of the system. So it may be a way to put supply at the other end of the line just to add some balance and reliability there.

As of right now, there's no need for that. What we have right now -- again, during the storm we maintained all of our supply needs and pressures. So it's something that we're constantly evaluating, looking at where is growth, what are the next things that we need in order to add additional reliability.

DIRECTOR PFALSER: You had mentioned that part of your diversity in offsetting what happened was 50 percent you relied on and you said it was from your summer. Was that from futures, the natural gas that you had purchased for the summer, you used up during that?

MILES KENNY: Well, so the way a storage facility works in -- at the highest level, you inject supply during the summer lower-demand months. So generally speaking, during the lower-price summer months, and then you store that underground until the higher-demand winter months. So you're pulling out the gas --

DIRECTOR PFALSER: Okay.

MILES KENNY: -- at those summer prices.

DIRECTOR PFALSER: Okay. Do you have any idea why any government at any level would be adverse to natural gas, expanding natural gas? You know, there's been some comments that not only at the federal level, but also at the state, maybe local governments are putting in place policies that are moving away from natural gas.

MILES KENNY: I see no reason why you would do that.

DIRECTOR PFALSER: That's all I have.

SECRETARY KEOGH: Thank you, Director. And I'll turn to Director Bengal our Oil and Gas Commission.

DIRECTOR BENGAL: I won't take much time. What is the -- what is your service area? How many states does it cover?

MILES KENNY: We've got eight states. So Texas, Oklahoma, Arkansas, Mississippi, Minnesota, Louisiana, and Mississippi. I would have to write them all down.

DIRECTOR BENGAL: So I assume their service of gas -- the gas is sourced out of Texas.

MILES KENNY: Some of it. Yes, sir.

DIRECTOR BENGAL: Okay. Where is your storage primarily located?

MILES KENNY: On the Enable system.

DIRECTOR BENGAL: Which state, though?

MILES KENNY: I'm not exactly sure where the storage fields are located.

DIRECTOR BENGAL: But that storage can serve Arkansas -- serves your entire system?

MILES KENNY: It does supply portion -- a large portion of the Arkansas footprint.

DIRECTOR BENGAL: Okay. Are you -- do you -- are you looking for more storage? You mentioned the storage is not as -- are you -- is that part of your effort, to look at more storage at any point in your system or --

MILES KENNY: No. Actually, we just recently made a reduction in our overall storage. So again, getting too overall diversity of supply. So just recently we made a reduction in our Enable storage contract to allow us to bring in some additional types of supply on the system.

It would allow us to bring in more base load supply, more market area supply. And again, it just gets to our strong belief that diversity of supply is really -- to us, is the silver bullet.

DIRECTOR BENGAL: That is directly from?

MILES KENNY: Just multiple market areas.

DIRECTOR BENGAL: Okay.

MILES KENNY: So it's actually supply that's flowing in every day, not sitting underground in storage.

DIRECTOR BENGAL: Is that more reliable than sitting underground in storage?

MILES KENNY: I wouldn't say that one is more reliable than the other. I would just say that, again, if you -- if you looked across the industry as a whole, you may have seen wellhead supply that failed. You may have seen storage that failed. So and if you looked at all areas, a perfect solution would not have been the same at every single market in every area.

So again, just getting back to, you want to have as much different supply options as possible.

DIRECTOR BENGAL: Thank you.

MILES KENNY: You're welcome.

SECRETARY KEOGH: I just would like to follow up with one final question. I know -- I think we have a little bit of time.

But wanted to make sure that one of the conversations we had with the Public Service Commission representatives or Attorney General's office and the electric regional transmission organizations last week was regarding notification. That's something the governor heard, and I know I probably heard some conversation from you also.

What was -- what is kind of the industry practice along notification? And the comment made last hearing was that, I guess, Public Service Commission does have some regulatory requirements on the electric utility side, in the event there's a curtailment or brownout or blackout, that the customers are notified under a certain protocol.

I understand for your gas customers, your large industrial customers, that was -- there were some notices given as many of them called once they got notice about how to address that, perhaps because they didn't have a human needs assessment or an affidavit in place.

But I did -- we heard stories which may be very accurate that in some cases, someone showed up at, say, the front gate of an industry or, in fact, one of the state departments to the, you know -- there was a -- someone showed up at the gate to turn off the gas supply. That was the first notice they received.

Is there something that CenterPoint and/or other companies can do, or is there a best practice that you can evaluate going forward or give recommendations on how we -- we might work with you as state agencies to get notifications out during an extreme event so we can make sure everyone's aware that, you know, this may be necessary?

I guess we just want to make sure that we are working on the front end, as opposed to reacting to someone's concern in the future. So that's a question that I would like to ask about the -- do you have any thoughts or comments on that at this time?

CINDY WESCOTT: I'll answer that. Again, my name is Cindy Wescott and I'm Vice President of Regional Operations for Arkansas and Oklahoma.

And we are similar to Black Hills, actually. We couldn't have -- there was nobody that could recall us ever having to curtail customers in Arkansas. So this was definitely an unusual event and it happened very quickly.

The notifications that we did were primarily through media, and it started with press releases to customers and just the general public around February the 11th. Around February 12th, we realized that curtailment could be a possibility and that's when we started reaching out to our large commercial customers on transportation.

So that group is separate from the sales group, like Mr. Kenny had said earlier, where the sales group, we purchase gas for them. And as human needs customers, we're going to deliver that gas.

The transportation group is just like Black Hills' situation, is that gas comes across our system to those customers via a separate contract with a marketer.

We have over 600 transportation customers. We did find that there was some of the contact information that we had was rather stale. People come and go quite often, and when you're dealing with 600 different entities, it's difficult to have up-to-date information.

But what we have put in place is every April, and now every October, we're going to go through that entire list, make sure that the contacts that we are -- are up to date, so going into the winter months, we will at least have had -- hopefully minimized the number. That may change between October and, say, like, February, the event that we had right now.

So that was an opportunity that we found. We only have two people that are in that group, so it was a pretty daunting task to contact everyone. We're going to get multiple people involved with that contact if we are to go through an event like this again.

Like I said, you know, I believe that nobody really understood what the extent of this event was going to be until it happened. We have 307 -- 479 employees in Arkansas, and of them, there's over 300 of them that are field employees.

You know, these employees were having to respond to emergencies. Some of what they did also was have to go and physically curtail customers because we didn't want to take a chance on any of our human needs customers not being able to have gas.

And like Mr. Kenny said, there wasn't anything wrong with our system. We've partnered with the Public Service Commission over years and have spent millions of dollars to modernize our system. Our systems performed well. It was just the impact of the potential lack of supply and the requirement from our pipeline supplier to make sure that we were not delivering any gas to anybody that was not human needs customers.

With that being said, you know, it's an operational issue; being able to reach all of the customers was difficult during that time period. As you can imagine, the roads were slick. They were not necessary passable. So we did everything we could operationally, which did include having to shut in some of those transportation customers.

But we monitored the pressures. Our team did a fantastic job working with the suppliers that we had to make sure that what we saw in our system and what they saw on their system all matched up as far as pressures go and being able to deliver to the customers.

That's kind of a long-winded answer to your question, but I think that there's always opportunities to do better. And we're looking at trying to see what we can to communicate to these customers better. I do think that there's some education that needs to happen around what those transportation contracts mean. And we did see some of our customers that are -- maybe have a more robust group that manages their energy, and they actually voluntarily shut in because they realized early on what the cost was going to be to their bottom line on gas -- gas pricing.

So I do believe that there's an opportunity or education for the rest of the customers.

SECRETARY KEOGH: Thank you. And I would hope that that's the case, that people are thinking ahead and perhaps lesson learned for them as to be prepared as well and the customer to engage with their contractor facility.

But thank you. I grant anything that we as a state department can do to facilitate notification, expand your resources during an event, we stand ready to do that. So I looked forward to working with CenterPoint or Black Hills should that need arise again. So please let us know what we can do.

With that, I think that concludes our questions for you and appreciate your appearance on a rainy day. And thank you for coming in and being available to us and appreciate all the great work that CenterPoint does here in Arkansas and the services you provide to not only our residents, but our incredible business infrastructure and our government infrastructure. So appreciate y'all's time today.

With that, I think the next group I'd like to ask forward is our Arkansas Independent Producers and Royalty Owners. And the next group will come forward and we can hear from the production side as opposed to those that were distributing. Thank you so much.

Just state your name, title of the organization, and then welcome to begin.

RODNEY BAKER: Thank you, Secretary Keogh. Thank you, Secretary Keogh. I'm Rodney Baker. I'm the Executive director in the Arkansas Independent Producers and Royalty Owners, AIPRO. And we appreciate the opportunity to be here today and participate in the Task Force and really provide whatever corporation we can, obviously.

I would -- everybody probably knows this on your Task Force, but we did not respond to the survey. And I talked to Director Bengal about this because, as an association, we did not have the kind of specific information your survey asked for. We're more general in nature, and my comments today will be more general. It wasn't that we were unwilling; it was that we were simply unable. And I appreciate your understanding on that.

AIPRO's association of oil and gas producers was formed about 12 years ago, and we were created to represent oil and gas producers in Arkansas in the public realm, legislative, regulatory, also to conduct educational programs for the public to -- about the importance of the industry in Arkansas and what it means to the state.

AIPRO is comprised of members from all three of the production areas in Arkansas, that being the Arkoma basin, the Fayetteville shale, and south Arkansas oil production areas. As an association, we do not produce gas. We do not market gas, so that is not my area of expertise.

I will comment on the snowstorm as a native Arkansan and having experienced more winters than many in this room. I never recall a time when we had such low temperatures for such a long period of time with that much snow accumulation. We experienced parts of those at one time, but not all together.

And the impact of that, as we've heard

others testify today, was something, frankly, the state wasn't as prepared for, and obviously that's why we're here today.

It's not a typical snowstorm and it caused hardship for producers. Our job is to produce the gas, get it out of the ground. We don't operate as a company if we're not producing. And we bring it out. We put it in, typically, to a pipeline marketed by typically by third-party entities.

So molecules of gas that we put in, we're not necessarily aware of where they're taken out because they're marketed by somebody else and that's the way the industry is organized. Our members have to get it out, if it's going to be sold. And our -- we have field people. These are companies, and I've had a chance to talk to several of our members about things that happened.

And heating equipment and those kind of things, we actually have a fraction, number-wise, as compared to wells. So the top-producing wells are prioritized to try to keep as much gas going.

Our field staff, in many cases, worked around the clock. We had -- I had one member specifically told me that they had staff that voluntarily spent the night during those periods in their vehicles at well sites that were working. They were afraid if they left, they would not be able to get back in. The roads would not allow them to do that.

Other companies, I know, have required two people per truck to go out and visit these sites because of safety reasons, afraid -- as y'all know, these wells are located on the interstate of a nice off-ramp there. They're out in some pretty hard-to-get-to places sometimes. And if you get out there in the middle of the night, particularly if there's communication problems or other problems in the area, it's difficult.

These people were dedicated. They spent those many, many hours in those conditions out there trying to keep the wells producing. And whether that's rough or not, I don't know, but it's certainly dedicated and speaks well to those people.

Again, we were happy to answer any questions that we can today. And we do agree that we need take a hard look at some of these things.

SECRETARY KEOGH: Thank you so much for appearing, Rodney. And I know you have a diverse association with a lot of members. And we heard from Arkansas Environmental Federation last hearing who had similar challenges with the questions because, obviously, one answer does not fit everyone. And as an association, you represent the entire group.

But with that, we do appreciate your appearance today and appreciate the hard work that you and your organization does. Having personally experienced working in Arkansas production, those -- those sites are very remote, very extreme remote locations.

I know -- and I know that Texas and Louisiana production wells suffered greatly. I've heard anecdotal stories too about, you know, fields that had hundreds of wells had got down into, you know, not single digits, but maybe double-digit operating wells due to freezing at the well. So I appreciate you.

Do you know if Arkansas wells were able to produce during this and -- that a lot of Arkansas production, Director Bengal advised me, that doesn't stay in Arkansas; it moves into pipelines and leaves the state. But can you talk a little bit about the production experience during the extreme event?

RODNEY BAKER: To some degree, I can tell you that in some cases we had producers that were totally shut out. In other cases, we had producers that were able to keep a percentage of their wells going, but nowhere near the majority in most cases, maybe 40 percent. Of course -- again, they're prioritizing the more productive wells trying to get as much out as they can.

There were gas wells shut in all over the state. Some of our production areas include dry gas, which you still have to have some separation of liquids. And to the degree that those separators freeze up, that curtails your production.

Operators -- producers operate under sales contracts where it's basically best that they can do. And if they're trying to get out, you know, 100 units, whatever, and they had to keep the third-party pipelines informed, and that's what they called the nomination are process.

So if they get froze in, they quickly convey that information so that the people that are sending the gas to, or transporting gas, can adjust pressures and also decrease pressures, stop flow and cause greater freeze-ups, as I understand it.

But that was one of the things that our folks were doing during that time. We had members that were -- spent a lot of time, I know, talking to county officials about keeping the roads open. I mean, you've got to have the ability to get down the major roads, or at least the county roads, to where you could access your wells. In many cases, that was difficult to do during that process. And they did -- I think they did all they could.

There's no complaint, but could more be done? Probably. Is there some way to augment that in the future? Probably. You're talking, in the shale, what, six or eight counties, to the degree that public equipment could have been -- or National Guard equipment, perhaps, could have been used to help keep some of that access open might have been helpful. And I -- I don't have a specific example, but you just know when you're fighting that problem, any help you can get is important.

SECRETARY KEOGH: Thank you. That's an excellent recommendation. I will turn to Secretary Preston to see if he has follow-up.

SECRETARY PRESTON: Just going to echo Secretary Keogh's comments to you and your association. Appreciate all the hard work and everyone to go up there and circumstances to keep those wells operational.

And I guess since you can't, you know, really provide the testimony, the feedback is -- and you represent many different entities, but maybe from your perspective as a lifelong Arkansan, any thoughts or recommendations that this Task Force needs to think about or consider just reflecting back on what happened?

RODNEY BAKER: One of the things that I've heard from some of the members is that, again, it'd be a general comment, but their electric contract to operate their facility, some of them are, like, first off. If you have a demand increase, they're the first to go off.

Well, if you do that in this unique scenario, and cut electric -- electricity to compressors, then you shut down gas that needs to go to companies to produce electricity. To the degree that that's happened and to the degree that it can be anticipated and prepared for, that would be one recommendation, certainly, that we would -- we would make in that case.

I watched -- I watched the public service announcements about turn your lights off, keeping the lights -- and I remember following my wife through the house and turning lights off. She said, "What are you doing?" And I said, "We're trying to save electricity." "Well, that's happening somewhere else. That's not happening here."

Well, we're all related to some degree. More education as we approach these seasons and advising what could be done might help with consumering -- consumer part of that. It would be a small amount probably, but I recognize that part of our state has a lot of recreational housing, second home, second -- to the degree that those could be turned down ahead of time to a lower temperature than you would want to stay in, that that would perhaps help also. It's a small thing, but small things could have made a difference in parts of our state.

So that's something that, from my own personal observation, that I would offer up to you. But keeping the facilities with electricity that are moving gas, I think, is important. Keeping roads open so we can keep the gas coming out of the ground is important.

SECRETARY PRESTON: Thank you.

SECRETARY KEOGH: Thank you. Director Pfalser, follow-up?

DIRECTOR PFALSER: I don't have anything at this time. I'm interested to see what Larry has.

SECRETARY KEOGH: Director Bengal, the mic is yours.

DIRECTOR BENGAL: Thank you, Rodney, for being here today and presenting the comments. During -- I know you polled the Arkansas operators. Most of our gas roads are in the northern part of the state. Did they talk about the weatherization efforts? What is their concern or their feeling about that?

RODNEY BAKER: I've really not had discussions about weatherization going further. I can tell you that many of the companies tried to borrow and did borrow heater facilities to try to keep wells thawed out.

I know one example, talk about what they had and what they could borrow, maybe 60 units. And you've got a couple thousand wells, and it's very limited to that.

I can't answer knowledgeably about their opinion about weatherization going forward, other than to say when you have -- I typify this event as maybe a 1-in-50-year event, maybe one in more years. And the cost of being prepared for that, keep it all going, is probably going to be formidable and perhaps not doable.

DIRECTOR BENGAL: Do you happen to know what percentage of Arkansas' production remains within Arkansas?

RODNEY BAKER: No, sir. I really don't. In fact, I thought about calling you on that because I've asked of a number of companies. But like I said earlier, when you put molecules in the transport system, it's sold through a third party. So we don't know where they're selling.

My impression is that much of the shale goes out of state, as has been stated. And in a simplistic sense, if you think about, we had natural gas in the state before we had available shale and we were being served out of other places. That infrastructure is in place, so it wasn't, you know -- it wasn't removed or displaced by the Fayetteville shale production. Simply just went into the pipeline. Most case is going to be out of state, is my understanding.

DIRECTOR BENGAL: And the majority of those shale production is really produced by very few --

RODNEY BAKER: Yes, sir.

DIRECTOR BENGAL: -- three operators? So and the majority of that production is about -- accounts for 80 percent?

RODNEY BAKER: I'm sorry, I couldn't hear you, sir.

DIRECTOR BENGAL: That variable shale accounts for 80 percent of the state's total production?

RODNEY BAKER: Correct.

DIRECTOR BENGAL: So I was just concerned and just wondering if those three operators were looking at weatherization issues, given the fact that they represent the majority of the gas Arkansas produces.

RODNEY BAKER: I can only give you an opinion. I would assume that they are, but we've not had since that time meetings in the format where that can be discussed as to what each other is doing.

So everybody fought real hard to keep all they could -- I mean, I'm sure there's been a lot of consideration on what they ought to do in the future. I am hearing some of that, but I don't think they have the answer yet.

DIRECTOR BENGAL: Okay. Thank you.

SECRETARY KEOGH: Please communicate back to your membership anything -- again, the benefit of this process with the governor is to provide recommendations, to work with our partner, you know, other government groups such as our Public Service Commission, Attorney General's Office. All of us collectively are looking for ways to enhance the delivery of the services to our citizens.

So if there's any suggestions that we can do or any incentives or any regulatory strategies or perhaps, please don't regulate strategy, we appreciate that feedback so that we don't interfere with the marketplace or interfere with the -- with your efficient delivery.

Again, our keen eye on transparency and certainty for our customers in our utility, a lot of our businesses rely on that, particularly as they look at where to locate in the United States.

So with that, I have no further questions for this entity, so we may conclude a little bit early. But thank you so much for being here today. And I look forward to conversations with your members, should they like to come in and visit with myself or even Secretary Preston and our Director Bengal, Director Pfalser as we talk about ways to make our oil -- our production county for Arkansans as well the overall region. So thank you so much.

RODNEY BAKER: Thank you.

SECRETARY KEOGH: With that, we'll probably go ahead and take a recess here at this time. We'll be reconvening this afternoon, I believe, at

1:00 o'clock for some additional testimony. Those of you that -- here, if you'd like to monitor that, those are -- that will be focusing on the electric grid over the electric utility generators in the state, so we'll be hearing from a number of electric co-ops and municipal power associations, Empire Municipal Electric Company, Oklahoma Gas & Electric, Southwest Electric Power Company, with a -- then a break and we'll hear from Entergy, Energy Policy Network. And Jackson Walker Law Firm is a firm out of Texas who will present some of the Texas history, as well as PPMGR will be presenting some local legal representation.

So with that, that concludes the morning. Thank you for your time today. Thank you for making the effort to be here and look forward to providing additional reports and recommendations.

If you have any concluding reports or summaries that you have generated as a result of your own work, we appreciate being provided that if it's something that can be disclosed. We appreciate that. So please forward those, likewise, to our staff here.

I believe Troy Deal has provided you an e-mail address that we can receive any reports. I know MISO and Southwest Power Pool have reports that they've generated. Any presentation that might help us make sure that we get the wording correct in our reports.

Thank you so much for your attendance this morning.

(Whereupon the proceedings were adjourned.)

SECRETARY KEOGH: Good afternoon. Thank you for being here this afternoon. Today is June 1st, 2021 and we are here today -- appreciate your participation, those of you that have joined us in person here at the Arkansas Department of Energy and Environment Headquarters. We're simply here today to hear testimony for the Energy Resources Planning Executive Task Force.

I know we have participation also during this particular hearing time via Zoom technology. And we appreciate you also joining us when we get to the organizations that are able to remote in. We appreciate your willingness to participate.

Also we have the entirety of these hearings being live-streamed on Arkansas PBS on the ARCAN site, which is dedicated to making boards and commission meetings, as well as legislative hearings and other important matters available to the citizens of Arkansas. So this is being -- you're being recorded. You're being live-streamed. And we appreciate those. And we're trying to use every available technology that we have before us to make sure this information is being communicated in a transparent way.

So my name is Becky Keogh. I'm Secretary of the Arkansas Department of Energy Environment. If you've been to this building before, it was also the Department of Environmental Quality. We've assembled several other state agencies now in this building, so to comprise the Department of Energy and Environment.

I have the pleasure of serving this Task Force with Secretary of Commence Mike Preston. He joined us earlier today, but he is -- in his stead this afternoon is -- we have Director Sparks. And I'm going to mess -- your title is AEDC Existing Business Resources Division Director. So we're happy to have you, Director Sparks, representing Secretary of Commence today.

Director of the Oil and Gas Commission to my left, Larry Bengal. And then on my far right, Director Kevin Pfalser, Director of the Liquified Petroleum Gas Board that y'all -- the agencies that serve under our Department of Energy and Environment. So happy to have these qualified and respected Task

Force members joining me in this effort.

I'd also like to mention that there's a particular special guest live streaming this morning. I think my granddaughter is live streaming this afternoon and this morning. She's here in town from Houston, but she was interested in what was going on and so, hopefully, I'll say hello to Isabelle this morning -- or this afternoon now. Hopefully she'll enjoy, or perhaps not, although she probably endured the worst of the ice storm being there in Houston. They were quite burdened with not only the lack of electricity there in the city, but also the loss of water for several days.

But anyway, but they -- so fortunately Arkansas did not quite -- at least most portions of Arkansas, did not suffer for the duration that some of the communities of Texas and Oklahoma did. But we know that at least the event was quite unique and unusual and hopefully truly a 100-year event, as we all heard of it.

As I mentioned, this administration is very familiar, it seems, now with 100-year events as we've endured about three of them in the past three years. First a flooding event that affected many of our residents along the Arkansas River, followed by the, as you know, the global pandemic, and now -- and then the ice storm.

So we're kind of ready for those phenomenal and unprecedented times to move on. And we're ready to get back to normal. But in the event that we do have these events, and we know there are red flags for other events to occur as you know.

So the governor, in his wisdom, asked for the Task Force to be assembled to address this event, as well as to look at an after-action assessment and create lessons learned that will help us better prepare as the administrators and executives helping our citizens of the state.

But that culminated on March 3rd of 2021, when Governor Hutchison signed Executive Order 21-05, which established the Energy Resources Planning Task Force. The purpose of this hearing is to gather the information from testimony in order to better prepare our state's energy infrastructure in the event of another state-wide emergency in whatever form it takes.

As chair of the Task Force, I will call forward names of organizations that will provide testimony today. As I mentioned, we've had several sessions of hearings. We had one last week and one this morning and we have actually an additional session scheduled following this one this afternoon. And then we'll wrap up tomorrow with, I believe, we have three sessions -- three or four sessions scheduled as well tomorrow.

So all that is available to all of you to observe or monitor, watch. I believe it's being recorded if you want to access copies of it, if you don't have a chance to participate or watch this.

But today and those organizations appearing this afternoon, we'll ask you to come forward to the table to your left, I guess, to my right. But there is a mic on the table. I will ask that you turn it on. We'll have trouble with that. If it's a bright green light, that means it's on. If it's just a regular green light, it's off.

So please do. We can hear you up here, but it's -- I believe the folks that are live streaming cannot hear very well if you don't have that mic turned on.

Also when you come to the podium, I'll just ask each of you to -- whoever the representative or representatives are to state your name, title, and organization for the record. As I mentioned, we're recording. But we'll ask that each organization limit the testimony that's presented to five minutes collectively, if it's one of you, or multiple folks.

So after you conclude your testimony, I will then turn to the Task Force members and we'll -- we have a few questions of each of you, not any long duration. We will allocate 15 minutes, which may or may not be required, to follow up with any questions.

We've done our homework. We've read -- a number of submitted prefiled written testimony and responses to specific questions that we thought might be pertinent or relevant, and we appreciate that. We found that information to be very helpful and guide our thinking on this. If there's questions we haven't asked, we'll offer those as well.

Anyway, with that, again, I want to introduce a few key members of our staff before we begin this. I will introduce some of our staff that's supporting this is Beth Thompson and Troy Deal in the back. I know that we also have Andrea Hopkins up front. She will be our timekeeper. So she does it very respectfully, but she is stern so watch her closely. I'm teasing, but she's fine.

We have Tricia Treece and Dan Pilkington over there taking notes, copious notes that they're helping us go ahead and generate a draft report that we will be compiling based on what we hear today, and also reports that are provided to us as far as an analysis for the Task Force. So we hope that will be concluded. There is a schedule published that we propose to make a draft report available for public review sometime in August, with the idea of meeting the governor's requested deadline for his set of recommendations.

So we hope that we can conclude these hearings, as we said, this week and begin that process of assembling the recommendations. I know a number of organizations are doing their own separate reviews of the event, and we are more than happy to receive any that you're willing to share with us, reports that you've assembled that provide recommendations that we could include as well to make, you know the governor's office aware, to document what is going on across the various organizations to better serve our Arkansas citizens and to make -- to help organizations. One of the goals is to make sure that the state is providing necessary resources also.

With that, I will go on and introduce Shane Khoury, our chief counsel, is in the back of room. I see Mitchell Simpson, our Arkansas Energy Office Director here, Jeff Lemaster, our Associate Director.

I don't know if there's anyone -- we had Donnally Davis, but I think she stepped out. She's our communications -- chief of communications. So with that, I'll go ahead and open, Andrea. And I will ask our first organization to come forward.

If we can start perhaps with the Arkansas Municipal Power Association, we'll ask you to come forward and introduce yourself. And just to give everyone kind of warning, the Empire Municipal Electric Company, we'd like you to be on stand by and be our second speaker after they conclude their comments and questions. Thank you.

TRAVIS MATLOCK: Thank you, Ms. Secretary. My name is Travis Matlock. I am the Electric Utility Director for the City of Bentonville and I am representing the Arkansas Municipal Power Association today. And with me I have --

JASON CARTER: Jason Carter, general counsel for Arkansas Municipal Power.

TRAVIS MATLOCK: First of all, I'd like to thank you guys for looking into this event. Thank you for the governor for convening the Task Force and for inviting me to be able to come forward and just kind of describe what has happened over the last couple of months with the 15 cities that we represent.

So AMPA is made up of 15 municipalities of all sizes across the state of Arkansas, serving over 425,000 Arkansans. We go from very large cities, Conway, North Little Rock, down to pretty small cities, Osceola, Prescott.

Because of this diversity in size, we also have very diverse ways of delivering and providing power to the different Arkansans and that's kind of what I want to talk about today.

The different options that we generally have are based off of risk, whether you have diversified risk, which is -- it minimizes the risk to the municipality broken up between assets or different contracts. They have fixed-price contracts: They may own the assets, have a fixed price with a third-party credit-worthy counterpart.

These are places like Benton, Arkansas. They have a fixed-price contract that really limited their impact. Jonesboro has fixed price and they own assets. So they got away with little to no impact, or possibly made some money during this storm time.

The aggregated risk, which is why I'm here to speak to that, where the risk is managed by a third party, also called a full requirements contract, where the city has entered into a long-term contract with a third party to manage all of the risk that is associated with buying and buying power for this.

Bentonville has a long-term contract with SWEPCO right now. It has about, I think, 12 more years left on that contract. During the storm, we didn't experience any kind of curtailment. We didn't experience any kind of outages or lag. We assumed that we kind of skated through the storm, to be honest with you. Counted ourselves lucky that nothing really impacted us during the actual storm.

However, shortly after that, we got a call stating that our fuel bill that just gets passed through to everybody was going to see a significant increase. Didn't have that increase right at that time or anything like that, but because it's part of the formulaic rate for our contract, it was just going to be passed through from our wholesale provider to our citizens.

My typical power bill is around $4 million around this time, around the February time frame, so I was expecting maybe 2 to $3 million extra. We received a bill for $20 million at the time that our bill was due. Our -- our yearly budget for purchase of power is $46 million. So the February bill accounts for 43.6 percent of our overall purchase of power in this one three-day event that occurred.

And then with the continued SPP Day 53 and Day 120 settlement, there's still the -- still hangs out there that there's still some extra money that could still be coming our way that is due.

The -- the AMPA cities that have the diversified risk, like I said, they did not experience the kind of shift that we did. With the overall 15 AMPA cities, there was approximately $40.2 million impact to the ratepayers of those 15 cities, with Bentonville being the highest-impacted city.

Because of the $20 million bill, we are 41 percent of the overall impact that was to those 15 different cities.

It is a pass-through charge. It's that fuel cost. We're currently working with SWEPCO to audit the bills, just to make sure that everything is on -- aboveboard and everything is right to say that we have done everything that we can do to look at that. But the passthrough of the gas bill is really what is causing the biggest impact that we had to this -- because of this incident.

I can speak to those cities. Mr. Carter who is -- he can speak to some of the other cities. He has been involved with AMPA for quite a while and was, at one point in time, in charge of the North Little Rock electric division. So he is more acquainted with some of the other ways that the other cities have. And if he'd like to -- if you have any questions of him, he's more than welcome to answer those.

JASON CARTER: I don't have any general comments maybe beyond the comments we earlier submitted to the Commission.

But I do want to echo Travis' comments, that I appreciate your efforts and the time that you're taking from your valuable schedules to look into this matter. I think it's important. It's important to the State of Arkansas. It's important to the cities that we represent, as well. And I am happy to answer whatever questions you might have.

SECRETARY KEOGH: I thank you both for being here this afternoon. It's daunting information that you present to us about the financial impact to your cities. And we're pleased that you did not suffer some of the curtailments that some of the other parts of the state did suffer, in addition.

Although, as we -- as we're learning through this process, I think many were that, you know, they are -- there is a need for flexibility in some cases and desire for flexibility in others, depending on the cost impact that was provided.

So one of the things that I know, Arkansas happens to be blessed with a lot of abundant energy resources and a diverse energy resource sector. And we heard from the regional -- regional transmission, you know, groups on -- last week, like Southwest Power Pool, about the diversity of coal and nuclear and wind and solar and our cold days load, you know, all play a part, natural gas being a critical part during the storm.

But it seems that the shortage of natural gas really drove some of the curtailment, obviously, the natural. But obviously in the electric sector, utility sector. But do you know if you feel like your ability to access power from these various sources, I guess, the impact gas plays on that? Or do you feel like we can do something as a state to help make sure the diversity allows for better -- better use of other base loads or other sources during these excess demand events?

TRAVIS MATLOCK: So for myself and the two other cities that are in the long-term contract, the full requirements contract, we're kind of at the risk of who that provider is and their ability to access any of that power at any given time, whether they had the natural gas or the coal or the solar or the wind. We are wholly reliant on them to be able to do that.

Mr. Carter can speak to a couple of the other ones, but as for me and the two other cities that are in the long-term requirements, I'm -- that's all we can do.

JASON CARTER: And so and I guess that's true just in any cities in that full requirement contract. Typically, they're prohibited from entering -- constructing separate facilities or contracting with separate provides. That's a typical provision within a contract. It would, at least, be limited somewhat, if they were allowed to do that.

That allows their counterparty to try to project how much power is required and manage things on some things for fixed-price contracts. I think the challenge that the cities served by SWEPCO has was those are variable costs contracts as well. So I think that was one of the problems that they ran into.

Speaking more directly to your question, I know your question pertained to natural gas. I think access to natural gas is important. It's -- and it was important for Arkansas cities, particularly those that owned localized generation facilities. I know Jonesboro City and Water and Light was able to get gas access. And that really mitigated the financial impact to their community.

Conversely, just down the road, Paragould was not able to access gas generation. They have local behind-the-meter distributed ward cell generators, which are, you know, efficient natural gas generators within the community, but they do need gas for them. So that was problematic and they had a pretty severe price impact from that.

So I'd say access to gas is -- is very important. You know, it was a significant impact on -- on the Arkansas cities that rely on those assets, in addition to just impacting the markets overall.

SECRETARY KEOGH: Thank you. Sorry about that. I'm going to turn to my right and ask Director Sparks if he has any follow-up questions?

DIRECTOR SPARKS: Yes. In your opinion,

access to gas is critical, of course. What can be done to improve access to communities that have no generation power or can't get it? What's the -- an option?

JASON CARTER: I think if we can understand during emergency events, we can understand the availability of gas and how that gas can be directed best for the needs of society at the time that the gas supply is constrained.

If -- obviously, we need to be able to heat our homes, you know. But just because we've got gas to heat the home, doesn't mean we've got electricity to turn the fan that drives the warm air into the home. So both of those have to be able to work together when we're in an emergency-constrained environment.

Unfortunately, it does mean some -- probably some businesses, some industries, if we're going to prioritize things towards the need of society, that means that some of them are not going to have gas. So that's -- that's a process that I'd say should be looked into and should be managed.

SECRETARY KEOGH: Thank you. Director Pfalser to my far right, do you have any follow-up?

DIRECTOR PFALSER: Yes. Thank you all for being here. How many of your members have generating capability as a percentage?

TRAVIS MATLOCK: About half.

DIRECTOR PFALSER: About half of them?

TRAVIS MATLOCK: About half.

DIRECTOR PFALSER: Is most of that generation, would you say, is it in fossil fuel?

TRAVIS MATLOCK: We -- we've seen, you know, most of the recent additions in generation have been renewable.

DIRECTOR PFALSER: Is that right?

TRAVIS MATLOCK: You know, so North Little Rock, not far from where we sit right now, has a 42 MW run of the river hydro facility that they own that's just right -- if I had an arm good enough, maybe I could throw a baseball and hit it. It's too far away. But most of the other development has been solar.

Now, the communities do have older generation fleet that's out there, that's localized generation. Those are going to be natural gas or diesel-driven, you know, facilities to generate electricity with those.

DIRECTOR PFALSER: Okay. When it comes to an event like we had, what is -- what is y'all's thinking when it comes to, can renewable be used for base level?

TRAVIS MATLOCK: I think the answer to that question is no.

DIRECTOR PFALSER: Okay. So it would have to be fossil or nuclear or something along those two to sustain through something like this?

TRAVIS MATLOCK: Yes.

DIRECTOR PFALSER: And I think you mentioned in your written testimony that most new generation that's coming online is renewable, and so that can be problematic if it's not -- if we have some fossil-driven generation that is due for obsolescence and we have no plans to replace those with like, it could be a problem down the road, you know, with the event such as this.

TRAVIS MATLOCK: Personally, I think that it is concerning. I understand there's a lot of environmental concerns that are out there. So I use my words carefully when I sit in my building and talk about that.

But it's -- there are environmental concerns related to the consumption of fossil fuels too for electricity. That being said, we think that the most important thing that we do in society is provide reliability. And that when reliability fails, people will lose their lives from that, that we have to have reliable electricity.

And while we pursue cleaner options continually, we can't abandon reliability in the pursuit of that. And at least in the -- in the short foreseeable future, that's going to mandate some use of fossil fuels, in my opinion.

You know, we've got a great fleet in Arkansas of good fossil fuel-driven plants, and you know, natural gas is a critical fuel, I believe. Some people see it as just a transition fuel, but there's a debate, I think, whether there's a transition fuel to cleaner electric sources or just something that needs to be used in the long term, but it's going to be critical either way.

DIRECTOR PFALSER: With the use of, of course, natural gas we had freezing problems, you know.

TRAVIS MATLOCK: Yes.

DIRECTOR PFALSER: I think you alluded to Paragould maybe couldn't get gas, even though they had good equipment. So it appears that if there had been weatherization in place, that that could have been avoided, possibly, depending.

And there's been some discussion today and the last time we met about how we do that. What would be your recommendation, as far as weatherization goes, to the wells and who's going to pay for that and how is it going to be done?

TRAVIS MATLOCK: Weatherization is a -- that's a really hot topic right now, about how much is enough. And you know, do you plan for the 100-year event when we have weatherization.

I know I had some in-depth conversation with Jonesboro and the facilities that they had, about the preparation that they did of their plants to try to ensure that they were available for operation. You know, it's protecting control panels and protecting valves and switches and things that have to operate.

With the temperatures that we had, they still had challenges. I mean, they felt like they were very proactive in trying to winterize their facilities, but they still had challenges during the storm. It was just a very extreme storm.

DIRECTOR PFALSER: Thank you.

SECRETARY KEOGH: Thank you so much. I will add to your comment. I know you mentioned environment is important, as is our reliability, and something that, you know, we're aware of. And I think the public has to be aware of is that any kind of affect of a utility or electric infrastructure can have an adverse effect on the environment.

We had a number of calls where there were natural gas interruptions, as we have a number of calls regarding how it might cause the disruption of some of the environmental controls that were in place in a number of operating companies.

And so it's important that while there's fuel supply, that those controls remain in place and functioning throughout the storm event.

So appreciate the thoughts that you have regarding the supply, but also we have to look at it from a holistic standpoint as well.

So with that, I'm going to turn to Director Bengal. Do you have any follow-up on this one?

DIRECTOR BENGAL: Just thank you for your comments.

SECRETARY KEOGH: Didn't leave you much time.

DIRECTOR BENGAL: The increase of cost from 4 million to the 20 million in Bentonville, is that due to gas prices or electric prices?

TRAVIS MATLOCK: That was due to gas

prices, sir. That was per our conversation with our provider, that was what they had to pay for the gas and it was passed on to us based on our usage.

DIRECTOR BENGAL: Do you have a contract with SWEPCO?

TRAVIS MATLOCK: Yes, sir.

DIRECTOR BENGAL: And they provide electricity and gas for you?

TRAVIS MATLOCK: Just -- just the electricity. They provide the electricity to Bentonville. So whatever fuel charges they acquired in purchasing that, whether it was natural gas or whatever, it's passed through as part of the formula.

SECRETARY KEOGH: Thank you. If you have a follow-up question, you're welcome to ask it. Do you have anything else? Did you have another one?

Thank you for both being here. And anything that these -- the departments can do, Department of Commerce, as well as myself, are happy to work with you guys and your entities to address this, some of the pressures that you're under as a result of this, hopefully, and wish the best for the cities as they work through the financial burden.

And I know the governor has been in conversation with a number of you as well, to see what can be done also, given the state of emergency that was in place. So thank you for your time today and we'll look forward to hearing more, hopefully avoiding that in the future. So thank you for coming forward.

TRAVIS MATLOCK: Thank you very much.

SECRETARY KEOGH: At this point, I will ask that Empire Municipal Electric Company to testify, or are they on Zoom.

MR. DEAL: They're on Zoom and they've indicated it's a little hard to hear the question. So when y'all ask questions, maybe get right up into the mic. That may make a difference for them.

SECRETARY KEOGH: Thank you. We'll move our mics forward, if that helps Empire. But I'll ask you two, can you hear us? You can? Okay. Great.

DIRECTOR PFALSER: One thumbs up.

SECRETARY KEOGH: I see a thumbs up. So I'm going to ask the representative to introduce yourself, your title, and your organization and go ahead and begin your opening comment. Thank you.

AARON DOLLE: Can you guys hear us okay?

SECRETARY KEOGH: Yes. We can.

AARON DOLLE: I saw the thumbs. I couldn't tell if you were up or down.

My name is Aaron Dolle. I am the Senior Director of Energy Strategy for Liberty Empire.

NATE MORRIS: My name is Nate Morris. I'm Director of Transmission Planning and Operations here at Empire District.

SECRETARY KEOGH: Well, thank you. If you want to start an opening statement? Or do we have someone else?

TIM WILSON: Tim Wilson, Vice President of Electric Operations for Empire, or Liberty Utilities.

A little bit about our company. We're -- central region of Liberty is headquartered in Joplin, Missouri. We have approximately 175,000 electric customers in four states, which would be Missouri, Kansas, Oklahoma, and Arkansas. We also offer water, waste water, and natural gas services to small and medium-sized communities in Missouri, Arkansas, Illinois, and Iowa as well.

We're part of a larger organization, may have heard us called Algonquin Power and Utilities. We have other $15 billion of assets across the United States and internationally combined. We have over 3400 employees across the world. And we now have reached the 1 million customer connections worldwide and with assets in 26 states.

We're a part of -- we're really local and we're really proud of that, but we're also part of a larger organization.

In Arkansas, specifically, we provide electric service to approximately 4800 customers in the very northwest corner of this state. We have about 35 employees in the state as well, and have made over $1 million in structural investments over the years.

First off, I'd like to say thank you for giving us the opportunity to share our story as it relates to Storm Uri and its impact on our company, and most importantly, our customers in Arkansas.

We have answered the questions from the testimony, but I would like to give just a brief overview of what we believe the primary causes of the electric power shortage in Arkansas was during this February event, Storm Uri.

I think it was, first of all, historically extreme weather conditions, which combined, at least for us, both cold weather and large snowfall amounts. As a result, the record-breaking peak demand because of those conditions, as was previously mentioned by the group in front of us, fuel supply disruptions and shortages played a part in this, particularly from natural gas which hampered our generator availability and abilities to run at the levels we needed to. Also diminished transmission capability.

What we did do, though, was we took a multi-pronged mitigation strategy to combat the storm to meet our customers' needs, which include, we curtailed some of large industrial commercial customers, issued multiple peak alerts as you could probably imagine, both on social media and other communication channels, to all customers, including residential and commercial, throughout the event just asking folks just to simply conserve energy.

We implemented controlled interruptions of service to a limited amount of customers, which was typically in one-hour blocks which was what the SPP required, and I mentioned those on February 15th and February 16th. And we provided outage updates to customers regarding the actions being taken by the company on various occasions.

This was certainly an unprecedented event, but not one for which we had no warning or certainly were not unprepared. We worked diligently to ensure our power supply was secure, mitigate costs as possible along the way. Our team was prepared and our customers were aware of the challenges and risks associated with the storm event.

Again, thank you for having us here today. And me, myself, and Mr. Dolle and Mr. Morris would be happy to answer any questions you may have.

SECRETARY KEOGH: Thank you for that excellent testimony. We appreciate the information you provided, also as you mentioned in writing. It is very helpful.

Some of the conversations we've had this morning regarding, and previous hearings, was related, you know, as we mentioned, to cost impact and the ability to have customer interface or awareness, you know, in terms of flexibility to, say, on the electric side having interruptible tariff processes, whether there's something comparable on the gas side, if you're -- if you're actually -- with the natural gas suppliers and those providers this morning.

If there's something -- and the question I guess comes to mind, the other fact we talked about is notifications to your customers when there was that sudden risk or the need to curtail.

So how was your experience on that? And is there any lessons learned that you would share with us as to maybe best practice on how to encourage those customers that might be flexible to take -- you know, to, in advance, notify you that they would be willing or volunteer for a curtailment, either to, you know, prevent cost increases or to be able to mitigate, you know, damage?

But and then also how to -- how -- anything related to how you notify those that you do find necessary to curtail?

AARON DOLLE: Just to make sure that we're answering the question as we heard it, you had a question originally about natural gas supply and then the curtailments and any lessons learned from notifications, correct?

SECRETARY KEOGH: Right. I guess, two points. Did you have any -- do you have any recommendations on how to identify those customers that might be willing or voluntarily take a demand reduction in advance to mitigate the kind of cost scenario we just heard?

And then also, is there any lessons learned on notifications to customers that you do find yourself needing to curtail?

AARON DOLLE: Sure. Great questions. We do have interruptible tariffs to the extent we have customers who are willing to take advantage of those.

The storm, if you recall back in February, was kind of predicted to happen a little sooner than it was and not quite as extreme as it was. So we began our preparations at the beginning of February, what was just expected to be cold weather, not necessarily to the temperatures and not necessarily sustained as long a period.

As that got pushed out and the temperatures got lower, we doubled our efforts to ensure that we had adequate fuel supply and adequate fuel delivered to be able to provide reliable power to our customers.

We did reach out to our industrial customers, starting with those that had curtailable contracts prior to any curtailment instruction, just to make sure that we had the right personnel, right contact information, and that they were aware of what may be coming, just as a preliminary notification.

As we got closer to the storm and as we got to the point where we were asking customers to curtail, we did reach out to those channels, both industrials that had curtailable contracts and as well as some other industrials, just to double-down on our conservation efforts.

So you know, the lesson that we have as far as, it's all about preparation, making sure you have the relationships and communications all established. I think Uri is a good opportunity to reach back out to any industrial to see what kind of additional reliability-type tariffs and curtailable contracts are available to ensure reliable power.

So as far as, we did double-down on those efforts for commercial and -- and for residential as we got into the storm with all sorts of social media posts and communication channels. And to be honest, the industrials did a terrific job in our service territory of not just curtailing load, but curtailing it for a sustained period. We had entities who curtailed all the way through Friday without even being asked for some of the curtailment. They notified us that they were going to continue to curtail.

So terrific cooperative job between the utility and the customers that did shed a significant amount of the expected load. So as Tim mentioned in our intro, we exceeded our all-time record peak, and we exceeded that with conservation efforts from all classes, and including some significant industrial load that was either interrupted or run down, to a certain extent.

So that just can give you a feel for how extreme the weather was and how much the load was impacted. We're a peaking utility and we tend to peak more in the winter than we do in the summer, which has been a departure for us over the last 20 years. And so this was a -- this was a significant effort from both entities to ensure reliable operations as possible.

SECRETARY KEOGH: Thank you for taking that double-loaded question. I appreciate that. I think that's a very good piece of information for us to capture.

Because as we've heard earlier some need to create that kind of communication network with their customers, that there was maybe a lack of that, given that this was unprecedented and been decades since Arkansas had faced similar pressures on our -- on our fuel supply.

So thank you for all the work that you did to do that on the front end, and I appreciate y'all's effort.

I'm going to turn to any follow-up questions, Director Sparks? Thank you.

DIRECTOR SPARKS: Sure. Thank you, again, for participating in this hearing.

In hindsight, looking back, what would you, could you, should you have potentially looked at that you're now aware of that maybe we weren't at the time?

AARON DOLLE: Yeah. Great question. You know, we felt prepared from an emergency operations procedures that we -- we've had, you know, our EOP manual established for a while now and we implemented that without issue.

As far as, you know, what kind of lessons learned and -- I think what it comes down to is, you know, we believe in a diverse fuel supply. But we also believe that we have to be prepared in that diverse fuel supply to have, you know, the necessary reliability investments associated with that.

You probably heard a lot about winterization efforts. Winterization efforts are critical. So for example, for us, we have two older wind farms that are in Kansas on purchase power agreements that expire in the next four years and seven years respectively. The wind farms were -- were installed years ago to where they didn't have the same cold weather packages that are now available.

We have three wind farms that are near our service territory that were either complete or in construction phases to be complete. All three have cold weather packages on them. All three were able to deliver power beyond a P50 level during the storm to the extent the wind was blowing. So it was a -- a really were important reliability package that we felt necessary to have from our wind farms.

When it comes to other fuel supply, dual-sourced units, any unit that can take any kind of dual-fuel was critically important to us. We did have natural gas disruptions. We are on a pipeline and we are the second-to-last customer on that pipeline.

So if you can imagine the pipeline is a giant straw and you're the second-to-last one, if you end up with under-delivery or overconsumption, your gas pressure starts to fail. So we did have some very serious issues with falling gas pressure Sunday, heading into the Monday and Tuesday curtailments, where we ended up having to run our two combined-cycle units that we had procured sufficient fuel to run them at their economic max, that we had firm delivery contracts. And we had to run those at the very minimum, just to be able to maintain reliable pressure for our units and not cause a series of drips.

So what we experienced, we have other thermal generation on our east side that was dual-fuel. Because they were dual-fuel, we did some fuel on-site. We did expand our storage tanks prior to COVID in case we had a fuel supply disruption. Plus we were on non-interruptible natural gas delivery. And we were able to utilize those. We have a seven and ten-day tank, depending on which unit. And we were able to utilize that to stay online as much as possible and utilize almost every single bit of fuel that we had for delivery.

So I think part of the lesson learned is the investments for reliability from the generation resource perspective should not go unnoticed, that we need to be looking for multiple ways to deliver fuel. We need to be looking at what options there are to increase reliability and whatever products the SPP task force that's set up to investigate Uri, what kind of market products are available to encourage investment in reliability products.

TIM WILSON: I'd also add on that something that we learned that was of huge benefit to our system and to our customers was having conversations and collaboration with our neighbors, specifically over a heavily congested flood gate that's positioned in our system with regards to market-to-market payments.

It's the most historically congested path on our system within the SPP. We were able to increase that capacity on that line 25 percent. Doesn't sound like much, but it was crucial with how our generation fleet is positioned within our footprint. That allowed generation to be dedicated to supporting our customers during that time for system support, versus mitigative on -- mitigation on flows during heightened transfers across the markets.

So we saw a much -- a huge amount of benefit to that directly. And from those actions that our company took, we foresee that be integral into future events as well.

The communications out to the field to field devices, we see that as -- as showing huge benefits, to have realtime system awareness and system impact. As this whole event transpired, there were -- there were areas of our system to where communication is not deployed because it is a rural system.

The majority of our footprint is rural, like a majority of the state of Arkansas is. And in that, we recognize that the costs to the deploy communications need to be vetted against what our response is and how we can also respond during times of crises, such as this.

Our monitoring of our entire system load was effectual, but not as efficient as it could have been had we had more communications platforms deploy across our system.

DIRECTOR SPARKS: Thank you.

SECRETARY KEOGH: Director Pfalser, do you have a question?

DIRECTOR PFALSER: Yes. That puck -- are y'all able to hear me okay? Okay. Got a thumbs up.

Appreciate you all being with us. As it relates to weatherization, you referenced the weatherization of your wind generation. Is this something that is typically used throughout the, like, the wind generation out in west Texas and Oklahoma? Do most people that have wind generation choose to weatherize them like you were suggesting you all did?

I think they're muted.

AARON DOLLE: Can you hear me?

DIRECTOR PFALSER: I can.

AARON DOLLE: Okay. Yeah. To be honest, I probably can't speak to what packages have existed across the footprint and SPP sitting on approximately 26 gigs of wind at this point.

What I can tell you is what I've heard. We've been through a few of these meetings in some different states and utilities, especially the newer wind farms that are being constructed, tend to have that availability, to have the cold weather package on them.

And from what I have heard, the utilities have been taking advantage of those with the newer facilities that are being brought online. I'm not sure if there's been any cold weather packages to retrofit any of the older existing facilities.

DIRECTOR PFALSER: Okay. And if -- with those units that you had, as long as the wind was blowing, they continued to operate?

AARON DOLLE: They did.

DIRECTOR PFALSER: The weather that we saw did not impact them in -- or the week of -- in February that we're all thinking about?

AARON DOLLE: Right. The -- the Tuesday second curtailment, there was not a lot of wind expected, so we did not get any wind generation. But the Sunday and Monday, we did generate wind. And my recollection is it was above the P50 level and without any issues.

DIRECTOR PFALSER: Okay. In your testimony that you sent in, you referred to -- you had a -- you used the language that investment signal, and you used this in relation to Southwest Power Pool, that they would need to send the correct investment signal.

What is -- what do you mean by that?

AARON DOLLE: That's -- I'm really happy you asked that question.

So in February, I believe, of 2019, we were in not as dire of a situation, but in an EEA situation with SPP, where we started to kind of export. It was ensuring fuel adequacy. 2019, we also had a series of conservative operations declarations.

The issue that the company saw is when we looked historically at the locational marginal prices, the pricing that energy gets sold at during those times, it was extremely low. It was -- it was $20 and it didn't move much. And part of what complicates this, we don't want our customers to have to pay high prices.

But we think is appropriate is when you

need additional investment, whether it's additional resources, whether it's battery placement, additional units, you have to send the right kind of investment signals. And we believe that it's two-fold.

We believe that the locational marginal prices, the marginal prices, the prices off SPP should reflect the situations on the ground.

So at the end of the day, this storm produced 3000 to $5,000 prices. And although those prices were extremely high, those prices do, in fact, send the right signal that additional generation is needed during those reliability initiatives.

And I think the other fold is it's not just in the L&Ps. It's in other reliability-based products.

So what our hope is that comes out of the continued investigation of SPP, since they're in charge of the reliability, is that we're able to create market products that incentivize the reliability of the system, so that customers, utilities can all be on the same page about ensuring that the investments that the utility is making to ensure reliable operation of the system are not just put solely on the back of the customers. Because at the end of the day when we end up in a reliability scenario, it's everybody that benefits from that.

DIRECTOR PFALSER: Okay. And you were -- that comment was made in relation to storage. You're talking about reliability going forward into the future?

AARON DOLLE: Yes.

DIRECTOR PFALSER: So would we rely on MISO and SPP to kind of direct the effort as far as the mix between renewal and base load for reliability? Or would that be somebody else's purview, to lead that effort?

AARON DOLLE: I think it's most effective if the RTOs that are there to ensure the reliability as the balancing authority create the market products that send the right investments signal to the utilities.

DIRECTOR PFALSER: Okay. And as far as base load generation into the foreseeable future, what would be your recommendation? What kind --

AARON DOLLE: To also base load --

DIRECTOR PFALSER: What kind of fuels for base load generation do we need to be looking at?

AARON DOLLE: I think -- I think it's our belief that a diverse fuel supply is what is needed. You know, there's been a transition to natural gas, and I think part of the concern on that natural gas is you still have to manage the reliability of not having an on-site fuel supply.

So whether that's increasing the ability to do dual-fuel, whether that's, you know, putting smaller LNG facilities next to your natural gas supply, whether it's just winterizing -- we had --

We had issues across our generating fleet based -- from base load to intermediate base load to peak. We had coal plants that had frozen coal and tripped offline and were unable to generate. We had low gas pressures issues on some of our natural gas thermal generators. And on some of our wind farms that did not have the winterization efforts, we had frozen turbines.

And so what it comes down to is having that diverse fuel supply that's able to navigate the reliability constructs that we find ourself in today.

DIRECTOR PFALSER: Makes sense. Thank you.

SECRETARY KEOGH: All right. Director Bengal for your follow-up? Thank you.

DIRECTOR BENGAL: Kevin had a lot of good questions so I don't have much to follow up on.

So when you say dual-fuel, you're referring to natural gas and fuel oil in that particular case you're referring to?

AARON DOLLE: Could you repeat that question?

DIRECTOR BENGAL: When you said dual-fuel, you have a generating unit with dual-fuel capacity, was that natural gas and fuel oil?

AARON DOLLE: Yes. Yes. For us, we have -- we have units that have dual-fuel capabilities so they have natural gas and fuel oil. We don't know -- we don't believe that it's going to be exclusive to that.

But being able to -- again, it just comes down to a reliability initiative, to be able to generate on multiple types of fuel, specifically fuel that you can keep on-site helps to manage some of the reliability concerns that you can have from having to have reliability supply of fuel that travels through pipeline.

DIRECTOR BENGAL: What would be other examples of on-site dual-fuel?

AARON DOLLE: Right. I think -- I think what we're starting to see, and I think what we put in our testimony for our 2022 integrated resource plan that is a robust 30-year plan, is we're starting to see what other kind of dual-fuel capabilities are out there.

There's overfiring with hydrogen that people are looking at. There's storing with battery that's being looked at. I think even city utility, they had a different dual-fuel. They had some propane fuel that they used. So it's looking at a variety of resources, seeing what -- what your facilities can manage in a reliable fashion that is able to achieve the, you know, the dual-fuel capability or the reliability that your customers expect.

I don't know that it's a singular technology or the value or fuel oil or diesel.

DIRECTOR BENGAL: And one more thing. Would you define -- you used the term "reliability-based products". Would you define what you mean by that, outside of the fuel use?

AARON DOLLE: Sure. Sure. So -- so the way -- I can give maybe a couple of examples that may be helpful.

So the way that SPP has managed what they need in the power pool has been to create market product. So I think, you know, we're familiar from a high level of locational marginal prices, which is, you know, the emergent price that you sell energy at.

And we're familiar somewhat with the ancillary services.

You know, SPP has needed additional ramp, which is the ability to bring generation online quickly during ramp shortages. And they have created a market product that ought to be in place relatively soon here, to provide compensation for units that are available to provide ramp.

So it's -- I can't tell you exactly what form it will take, but it is talking to those entities at SPP that are on the realtime desk, what products do you -- what sort of generation do you need to have in your mix, what sort of capabilities with that generation do you need to have, and what kind of market products can you create that incentivizes that kind of generation to be built.

DIRECTOR BENGAL: And that is the role of the RTO, to be doing that.

AARON DOLLE: That's who?

DIRECTOR BENGAL: The role of the RTO, to do that?

AARON DOLLE: Yes.

DIRECTOR BENGAL: Thank you.

SECRETARY KEOGH: All right. Well, thank you so much for your time. I've enjoyed -- been educated quite a bit in your testimony. It sounds like you were well prepared and your customers benefited from that preparation.

So thank you for being here today and thank you for your suggestions. We'll look forward to follow-up as we move forward. Can you hear? I don't know if y'all can hear me. Thank you, again.

Technology is a blessing, but sometimes we're still learning it as well. So appreciate your participation. We've been able to hear you quite well. So thanks so much.

AARON DOLLE: Appreciate the opportunity.

TIM WILSON: Thank you.

SECRETARY KEOGH: And I failed to -- thank you. All right. Well, continue to participate if you wish on Zoom or follow up on the ARCAN site.

I failed to notify the folks that were next, which would be Oklahoma Gas & Electric. So I apologize for no warning, but if you want to step forward, we'll take your testimony.

And then following that, we'll ask Southwestern Electric Power Company to step forward, so.

DON ROWLETT: Thank you very much for the invitation today. My name is Donald -- can you hear okay?

SECRETARY KEOGH: Can you make sure the bright button is on for our --

DON ROWLETT: The bright button -- the bright light came on. So is that better?

SECRETARY KEOGH: That's much better.

DON ROWLETT: Once again, thank you for inviting OG&E to participate in this today. My name is Donald Rowlett. I'm Managing Director of Regulatory Affairs for Oklahoma Gas & Electric company, or better known as OG&E.

We serve around 69,000 customers in the Forth Smith area and 24 surrounding communities. Our service territory covers about 1,000 square miles around western Arkansas. And then is contiguous service territory throughout much of Oklahoma.

As we've talked much about it today, and I'm sure you've talked about it in your previous sessions, the February winter storm event was nothing like we've experienced before. OG&E's goal is to provide uninterrupted power to all customers at all times. During the February storm event, it became clear that meeting this goal was going to be challenging.

As the challenge grew, we -- our focus

became two-old: To maintain generation to prevent uncontrolled outages, and to protect our continued ability to procure fuel to serve customers in the face of extraordinarily high natural gas and wholesale energy costs.

Thanks to planning and coordination with the SPP, proactive conservation efforts -- and we would like to commend our customers, both small and large, for their conservation during this event, and our focus on keeping generation sources online, we were able to avoid uncontrolled outages.

While some customers experienced controlled service interruptions, they were limited in scope and duration. 84% of OG&E's customers maintained service throughout the event. If you -- if you look at the customer hours served from February 7th through the 21st and you take those hours, OG&E was able to serve about 99% of those hours.

So while there were outages, they were controlled outages. And some customers had periods of time without service as overall service delivery during that period of time was pretty good.

OG&E's goal is to maintain -- minimize service disruptions and give advanced notice to customers when we can. We worked to communicate outages transparently and responsibly to make customers aware that interruption could occur. We credit OG&E's customers for the important role they played in conserving fuel during the unprecedented event. And we continue to seek ways to enhance our customer communications.

You know, I experienced the event through the Oklahoma City television market. It was -- it was really amazing to me that SPP became something that the television news reporters would be very conversant in, and the different levels of events, EA-1, EA-2, EA-3 became just like -- it was almost like the different levels of severe weather warnings. It sort of took on a similar tenor to it.

OG&E doesn't profit from our fuel cost. As a regulated utility, we pass those costs directly to customers with no markup. We worked with -- been working with the Arkansas Public Service Commission. We worked to leaven efforts to spread the costs to customers over ten years to reduce the financial burden on customers.

And we're grateful for the Arkansas legislature providing a tool, another tool, the securitization legislation which may also negate the financial impact on customers.

Once again, I'd like to thank you for the opportunity to participate today and would love to respond to any questions or recommendations that you might have for us.

SECRETARY KEOGH: Thank you so much for your comments. Thank you for coming to Arkansas to represent your organization, and on a not particularly great weather day. We appreciate that. But we appreciate that it's not an extreme weather day either.

But with that, you mentioned you have some diversity in your power supply or your fuel supply; is that correct? Or can you describe exactly what that is and how that might play into what your situation was during the event?

DON ROWLETT: We do. OG&E has about 7200 MW of generation capability. About 1800 MW of that capability is coal-fired. Prior to our compliance with Regional Haze, we had about 2800 MW of coal. There were two 500 MW coal units in the Muskogee area that we converted to natural gas-fired.

You know, one of the things that was very important to us is as we came up with a strategy for complying with Regional Haze was to maintain fuel diversity. So of the 2000 MW that were impacted by the Regional Haze account, we ended up basically hedging, if you will, by putting scrubbers on 1000 MW of coal generation so we could maintain that and 1000 MW we converted to natural gas.

We have -- we have wind generation. There was a discussion earlier about cold weather packages. We don't -- we don't have those on our wind facilities, but I know -- I think anything that we would be building in the future would have that.

One of the things we -- we also purchased two combined-cycle units. One of them is known as our Red Bud plant; the other is McClain. Those were originally built as merchant plants, and they were built in the early 2000s.

We experienced a similar in the event 2011, extreme cold weather. And after that event, we put -- we -- we started putting some protective measures in place. One, we put roofs on both. Both units, we put roofs on. The emergency plant we built just wide open. And so we put roofs on both units and then we started building enclosures around some of the more critical components.

So that is not necessarily diversity related, but combined-cycle units for natural gas tend to be base load units. And to make sure that they were available during a similar event that we had in '11, we did the weatherization to those units and they performed well during this event.

But our -- we have a small amount of solar. It's not a significant amount for us today. We have wind, natural gas, and coal would be the resources that make up our mix.

SECRETARY KEOGH: All right. Thank you. Sounds like you've learned a little bit of lessons just through that process, so that's something that we should all pay attention to, I guess, as we see the change in the fuel fleets going forward.

With that, I'll turn to Director Sparks if have a question.

DIRECTOR SPARKS: I don't right now. Thank you.

SECRETARY KEOGH: Director Pfalser?

DIRECTOR PFALSER: Certainly. Thank you for coming over and joining us.

The cycle units that you were just talking about, combined cycle, is that what you refer to them as?

DON ROWLETT: Yes.

DIRECTOR PFALSER: So are these dual-fuel?

DON ROWLETT: Well, the ones that we

operate are not. And by combined cycle, they're units that sort of use the -- sort of two ways to get the energy out of the natural gas burn. One is there's a turbine, a combustion turbine that, I guess what I'll say, mechanically turns the generator. And then the exhaust gas is fired into a boiler, a steam boiler. So the steam generates a turbine as well, so that's that combined cycle feature that those have.

DIRECTOR PFALSER: Okay. And so you all are a -- you generate electricity and then you are an electric company for the end-user?

DON ROWLETT: That's correct.

DIRECTOR PFALSER: Okay. So do you have the ability to take your electricity and use it for your customers or do you sell it on the grid to, you know --

DON ROWLETT: Since we -- since we joined SPP and the -- since, I guess, the advent of the integrated market, we now sell every -- all of our -- all of our generation is sold into the integrated market and then all of our customer needs are purchased out of the integrated market.

DIRECTOR PFALSER: Okay. In your -- as far as going into the future, I'm asking this of all the electric companies, the base load generation seemed to be the problem with natural gas and the freezing of the wells, because a lot of electricity was produced by turbines.

Going into the future, what do you see the best fuel for base load generation to be?

DON ROWLETT: Well, I think natural gas is still the best fuel. You know, given -- given the environmental concerns of coal, I think, you know, the future base load generation, natural gas is still probably the most viable fuel.

I do think, you know, combined or dual-fuel capability would probably be something that should be considered. You know, all of our units are currently just natural -- solely natural gas-fired. The capability to fire with a fuel oil or some other source might be something to be considered.

DIRECTOR PFALSER: You mentioned that you put -- you did put scrubbers on one of your coal units; is that correct?

DON ROWLETT: Sooner -- our Sooner plant in north central Oklahoma has two 500 MW units and so we put scrubbers on both of these.

DIRECTOR PFALSER: That's an expensive proposition for older coal-fired units to come in an retro?

DON ROWLETT: Yeah. It costs around $490 million to put scrubbers on those two units. Those were completed in 2019, so relatively recent investment.

DIRECTOR PFALSER: Thank you.

SECRETARY KEOGH: Director Bengal, do you have follow-up?

DIRECTOR BENGAL: Just a quick one. What percentage of your generating capacity would you define as being satisfied with base load?

DON ROWLETT: You know, it's a difficult question to answer, particularly the way units are dispatched in Southwest Power Pool now today.

We probably have, I would say, 60 percent of the units that we have would be considered designed for base load generation. But on any given day, we might see 70 percent of the power in the Southwest Power Pool provided by wind. You know, for particularly a period of time with low load and high wind in western Oklahoma and the Texas panhandle, the base load -- normally be a base load unit doesn't operate like a base load unit. I don't know if that helps.

DIRECTOR BENGAL: So what percentage do you think would be a -- going forward as we look at alternatives, sources of power generation? What percentage of that need would come from a very reliable base load-type fuel?

DON ROWLETT: You know, looking at -- I guess, thinking about that, you -- typically wind generation might be accredited, even though it's a, say, 1000 MW of capacity for a wind farm, let's say. You know, that might be only credited for about 120 MW of capacity. And so we would still have capacity to meet our peak. And so that wind facility wouldn't attribute a lot.

So it would be dispatchable resources, which are typically fossil fuel, either natural gas or fuel oil, probably, would be the most likely items to meet that capacity.

Solar, on the other hand, has a higher capacity factor because it, you know, tends to be across the day. And it tends to be a little bit more consistent than wind. So you know, they're all subject to be -- solar could be also a good resource for capacity.

Although, you know, during this event we didn't get a lot of sun. We didn't get -- it really wasn't a very helpful resource during -- this event was all cloud cover.

DIRECTOR BENGAL: Okay. Thank you.

SECRETARY KEOGH: Well, just momentarily, did you have any recommendations regarding notification to your customers? Or any best practices that you found helpful to you during this process that you would want to share with us to include in the recommendation?

DON ROWLETT: You know, I think the thing that was probably most successful for us was communicating on every platform possible. Communicating with the traditional press, television, radio, print, and then communicating in a way the customers were accustomed to these days, Facebook, Instagram, and different social media. Because that's where a lot of people get their messages now. So communicate as many ways as possible would be our recommendation.

SECRETARY KEOGH: And do you think all your customers got notification?

DON ROWLETT: Well, I think -- I think most of them did. You know, to -- like I said, it was the messages and the potential for disconnection were sort of all over the airways. But you know, after the event there was some customers that said, gee, I didn't get any notice at all.

So I think we still have opportunities, opportunities to reach more people, or to maybe help people comprehend what that message means. When you -- when we say this, that means this could happen.

SECRETARY KEOGH: That was my point. I know during these sudden events, it's very challenging to make sure every point of notice is made and understood, as you said.

So thank you for your time. I think that concludes our questions. And we'll move on now to our next witness, or next company, which would be our folks from Southwestern Electric Power Company. If you want to come forward?

BRADLEY HARDIN: Thank you. Good afternoon. I appreciate the opportunity to be here and to share some information with you from Southwestern Electric Power Company.

For those of you who may not know, Southwestern Electric Power Company, often known by the acronym SWEPCO, is a three-state electric utility company. It's headquartered in Shreveport and we have about 530,000 customers of which 23 percent of them, or about 120,000, are located in Arkansas, the balance being somewhat evenly divided between

Louisiana and Texas.

We have -- the vast majority of our customers, as you might suspect, are residential customers. We serve parts of 13 counties, all of which are located in the western side of the state. Many of those counties share a border with Oklahoma or Texas. So that's how far west they are.

We have three wholesale customers, as you heard from Travis earlier: The cities of Bentonville, Prescott, and Hope, and their municipal electric utilities are our wholesale customers. The largest of our communities that we serve in Arkansas would be Fayetteville, Springdale, Rogers, and Texarkana, in that order.

We have three generating plants which are located in Arkansas: One in northwest, one in southwest, and a smaller gas-fueled unit, which is a peaking unit that's located in Washington County.

We have four generating plants located in Texas, and three are located in Louisiana.

We have a somewhat diverse generating portfolio, in that we have plants that are fueled by coal, one that's fueled by lignite, a number of them that are fueled by natural gas. We have a small amount of wind generation, which is located in west

Texas. That particular wind generation that we had in place at the time of this event was a purchase power agreement.

And just since this event occurred in February, we have placed the first of three wind projects into commercial operation. Those are located in Oklahoma. And the other two will be going online later this year, perhaps even early in 2022.

The -- when I refer to the diversity of the generating portfolio, I'm referring not only to the fuel sources, but I'm referring to the locations of those. They are truly spread throughout our three-state service area. In order to -- in order to be able to address local needs, as well as system-wide needs and everything that SWEPCO serves in all of our generating facilities, are located within the Southwest Power Pool.

We have, I would say, a brief period of controlled interruptions during the winter weather event. On Monday the 15th, we had an interruption, controlled interruption, that lasted just under one hour, 55 minutes to be exact, I believe. And we had about 5500 of our 120,000 customers in Arkansas impacted by that. That represents about 4 percent of our customers.

And then on Tuesday, the 16th, about 17,800 of our customers were impacted by controlled outages for about three-and-a-half hours. And that represents about 14 percent of our customer base here in Arkansas.

We were prepared for this in that we were advised on about the 9th of February that an appeal for conservation was warranted. And we began communicating that through news releases and through the use of social media, that conservation would be -- would be prudent, would be helpful for the upcoming period of time. And that, again, was on the 9th.

As SPP began notifying us that we were moving into an EEA-1, then 2, then 3, we were escalating our communications to customers. And we were using some of the same media communication formats that you heard earlier, issuing news releases on a regular basis, but also utilizing social media and also text messages to individual customers from customer service managers who are assigned to those customers. And I know, in my case, communicating with mayors, communicating with legislators, county judges.

I got the signal here, so I'll stop at that point.

SECRETARY KEOGH: Our timekeeper is stern. All right. Well, thank you for your direct testimony. I know I appreciate the information that you shared in prefiled testimony. That was very helpful to us as well. And we really appreciate the role that SWEPCO plays in the state. I know you are a valued member of the electric generation capacity in Arkansas.

So I guess with that, I will open -- I have a brief question about, you mentioned the notification. Do you believe -- you mentioned text messaging and stuff. Do you believe most of your customers that experienced a brief, I guess if you will, a rolling brownout or blackout, whatever, had that notice for the most part?

Have you ever heard any concerns or communicated that they -- that they were not somehow aware it was going to directly impact them or that the power would not resume after a brief outage?

BRADLEY HARDIN: Personally, I've had one. That was kind of a conversation I had with an industrial customer, a commercial customer actually, up in Springdale. And he indicated that he -- he felt like he had not been aware enough ahead of time.

But that was the one that I had. But again, I know that others of my coworkers did communicate with their customers as well.

SECRETARY KEOGH: I don't have any direct knowledge. I'm just curious what the reaction was in your -- in your service area.

So with that -- with that, I'm going to move to other members of the Task Force and we'll wrap up, perhaps with a second question later.

Why don't you go ahead, Director Sparks, with your questions.

DIRECTOR SPARKS: Yes. Thank you for being here. You indicated you had a customer that felt like they maybe didn't have adequate communication or at least warning. What would be adequate in the way of time?

BRADLEY HARDIN: Well, in the way of time, in that particular instance, I believe that he is one, like perhaps others, who we need to be adding to a proactive communication list. At the same time, again, we did issue news releases to the media which were reported. That's that press and the broadcast media, extensive utilization of social media. And often times people will get their news via social media faster than they will from print or broadcast media.

So we just tried to utilize all of the available tools out there to make sure someone has gotten the word. And sometimes, admittedly, what they may get is word of mouth from someone else who did get news out there. But we do try to communicate.

Certainly in that instance, we were doing what we could, when we could, as often as we could, to communicate that not only were we appealing for conservation but that we were moving into a period where controlled outages were a possibility.

DIRECTOR SPARKS: Thank you.

SECRETARY KEOGH: Direct Pfalser?

DIRECTOR PFALSER: Thank you for being here. That new coal-fired plant that came online a couple years ago down in southern Arkansas or down in that area, was that y'all's plant?

BRADLEY HARDIN: Yes. That's the Turk power plant. It went online in December of 2012.

DIRECTOR PFALSER: It's that long ago?

BRADLEY HARDIN: It's been that many years ago. That is one of SWEPCO's facilities, yes. That's a coal-fueled unit that is one of the most efficient, cleanest coal-fuel generating plants in the United States.

DIRECTOR PFALSER: And there was -- in earlier testimony, there was -- or might have been in the written, where the coal actually froze. I mean, is this -- are they just talking about uncovered coal that is on-site and just the water vapor or whatever is freezing on the coal, and so it makes it to where you can't use it? Or what were they referring to when they said the coal froze?

BRADLEY HARDIN: Well, that can happen. Typically at our coal plants, we keep a supply on the ground of about 30 days at full-load volume. So there's a lot of coal on the ground out there.

Typically what they do is continuously stir that coal, utilizing the large tractor equipment. They do that in the summer. They do that in the winter. But yes, there is a moisture content to coal. There's an even higher moisture with lignite. And in the extreme weather that we had, it can happen.

DIRECTOR PFALSER: Okay. Going into the future, what -- what do you see as the best fuel to be used for base load generation?

BRADLEY HARDIN: Well, you've heard it before. I will repeat and I will say natural gas.

Natural gas, largely for cost reasons, but natural gas for environmental reasons as well.

DIRECTOR PFALSER: Okay. And it seemed like the weatherization keeps coming up. And the wells that froze or prevented the supply of natural gas coming into the state -- or going to the -- for generation that was coming into the state, how do you see Arkansas playing a part in helping with weatherization? What could possibly be a solution?

BRADLEY HARDIN: Well, additional weatherization of the gas distribution system is perhaps warranted to ensure that there's no freezing, there's no locking up of the equipment that is out there. And at the same time, we make sure -- we try to make sure that as we implement controlled outages, that none of the natural gas distribution system is impacted by that.

DIRECTOR PFALSER: Ultimately, who is -- who would be responsible for weatherization of the natural gas system?

BRADLEY HARDIN: I believe that would be the natural gas industry.

DIRECTOR PFALSER: The producers of the wellhead, or the --

BRADLEY HARDIN: Yes, sir.

DIRECTOR PFALSER: Okay. And then one last thing, it was indicated earlier that the -- there was a belief that the RTOs were responsible for directing the effort towards diversifying the mix. Is that your understanding as well?

BRADLEY HARDIN: That's my understanding as well. Yes, sir.

DIRECTOR PFALSER: Okay. Thank you.

BRADLEY HARDIN: Yes, sir.

SECRETARY KEOGH: Thank you, Director Pfalser. Director Bengal, do you have any follow-up?

DIRECTOR BENGAL: Just a brief follow-up on the notice issue. The question heard earlier, that one of your customers in Bentonville, their bill went from 4 million to 20 million, primarily due to the gas issue, gas price increase, were they noticed of that pending fuel surcharge before it happened? Or did that just show up?

BRADLEY HARDIN: Well, as -- as he acknowledged, he was advised ahead of time that there would be some additional cost. He couldn't quantify it at that time, and frankly, I doubt that we were able to quantify it preconsumption, to know. We did not know what -- we would not have known what our fuel cost would be in order to be able to share with any of our customers what their fuel costs would be.

DIRECTOR BENGAL: So there was a notice for curtailments, as well as potential fuel costs? In some cases you would have done both, I imagine?

BRADLEY HARDIN: I suspect. Yes, sir.

DIRECTOR BENGAL: That's all I have. Thank you.

BRADLEY HARDIN: Okay.

SECRETARY KEOGH: Thank you for your time this afternoon. It's been very helpful. And I appreciate your participation and corporation of Southwestern Electric and all your efforts to bring clean base load to Arkansas. So thank you for that effort as well.

I'm going to ask a final organization today is the Arkansas Electric Co-ops. I'll ask you to come forward. And we'll extend the hearing time just briefly, because I know we've run a little bit over our scheduled time, but we expect to wrap this up in about -- as he said, if you wanted to begin your opening statement, and then we'll follow with brief questions.

ANDREW LACHOWSKY: Sure. Good afternoon. I'm Andrew Lachowsky, Vice President of Planning and Operations for Arkansas Electric Cooperative

Corporation.

Our 17 distribution co-op members serve approximately 60 percent of land area of Arkansas and a population and I'm going to refer to us as AEEC. We're the generation and transmission cooperative that provides the power to over 17 distribution co-op members.

So starting from a personal perspective, I have been an electric generation resource planner for -- or responsible for it for 30 years now. For electric generation planners, our goal and our standard is a level such that outages would be no greater than one day in ten years. I had hoped that I would hit retirement before that one day came, but unfortunately it did come.

The short answer to what caused the problem, well, it's the weather. I very much appreciate that this Task Force is trying to look at the complex issues behind that.

We're members of the Electric Power Research Institute, and they have begun a resource initiative last month that's due, in large part, to the outages experienced last summer in California and then certainly the outages that we saw here, and also the outages in ERCOT.

There's others in the room that are represented on that initiative, but one of the main questions that this initiative continues to answer to whether an outage at one plant has, over time, become more highly correlated to outages at other plants.

And this is exactly what we saw in mid-February with this cold-weather event, is the same issues that were causing outages at one plant were causing outages with the whole fleet. The zero-degree weather, along with snow and ice, was affecting gas-fired, coal-fired, and wind resources.

For some of the gas-fired resources that remain mechanically available, natural gas was not available. The frigid temperatures were causing electricity demand to spike. So not unlike what we heard with Empire, we have become a winter-peaking utility. There was 51 consecutive hours beginning on February 15th when our demand exceeded our all-time summer peak demand for firm load.

There are no easy solutions. And we point out in our comments that given that we're in the RTO environment, that one single utility cannot take actions that will ensure liability. We need for it to be RTO wide, actions that are RTO wide. But we do appreciate that SPP and MISO are both working for stakeholders to evaluate changes.

So we have both wind and we are adding solar. And I will say they are valuable energy resources. That nervousness we have is that it seems that more and more wind and solar are being added and they're being seen to replace resources that provide the reliability that's needed.

So we have 474 MW of wind from five wind plants, four of which are in Oklahoma, one in Kansas. They were 58 hours in mid-February when generation from all five of these wind plants, in that aggregate, were producing no energy.

And of course, solar, as you heard, wasn't performing well at all. And just with the 58 -- or 51 consecutive hours where our winter peak was exceeding summer peak, that included many overnight hours. So the sun is not shining over night. More energy storage isn't the answer either. Battery storage today is short term. Certainly, the technology continues to improve.

We do appreciate that natural gas companies such as Enable are already evaluating improvements to their system. In mid-February, for our two natural gas power plants that had the capability to burn fuel oil, we were doing so. Ability to burn fuel oil comes with additional costs and permitting requirements.

So our preliminary plans when the retirement of White Bluff and Independence retires would be to add natural gas-fired resources. We hope that the permitting with allow us to add fuel oil backup at that new natural gas facility, when and if that time comes.

Again, we thank you for your attention to this very serious issue and we look forward to being part of the solution.

SECRETARY KEOGH: Thank you very much for that testimony and your look to the future on your particular place.

I guess I would -- we heard some testimony earlier when we listened to natural gas suppliers, producers, and there was a conversation that developed around storage, not from battery storage but storage of the natural gas resource at critical operating sites, and we rely -- it sounds like as we rely on natural gas as a form of base load unit.

Apparently, the investment in storage, or disinvestment, has occurred due to the pricing structure. And everyone stores natural gas at a high, more expensive, perhaps that's not been the --

it's been hard to justify that, the storage.

Do you see that as a -- as something we should, or perhaps the RTOs, should plug and play, if you will, if natural gas is going to be a critical part of -- should the storage be a part of that overall investment as well, to provide some reliability to that, should we encounter a weather event like we had this past winter?

ANDREW LACHOWSKY: So I know you've been talking to the natural gas companies, but even this morning, Enable sent us something that was suggesting that they have an initiative, if they can get enough interest, to tie into the Perryville hub which is in southeast Louisiana. It was not experiencing the issues we were experiencing here.

So obviously, it takes significant investment. It wasn't cheap. They would be charging it through the gas rate, but we certainly are going to be one of those that sign up and have some interest in, at least, evaluating it and asking for additional details on it.

So that ties into some significant natural gas storage. It's my understanding that type of storage does not exist in the Oklahoma area. They rely a lot on actual production that was freezing up.

So in some ways, similar to us having a robust transmission system on the electric side, having that similar robust transmission system on the gas side would be valuable in this case.

And we would evaluate that additional gas cost to adding fuel oil and backup natural gas there at the plant. That's extremely expensive to do, liquified natural gas, but it is an option.

SECRETARY KEOGH: Thank you. That's helpful. Appreciate that. And I know that, along with our diverse fuel supply, with help us going forward.

So with that, I'm going to turn to Director Sparks again, if you have a follow-up question.

DIRECTOR SPARKS: Yes. Thank you. And thank you for being here.

In your testimony, there's written comments regarding other things besides weather. Earthquakes, flooding, terrorist events, what kind of strategies are we looking at that we could incorporate that would encompass all that type of activity as well?

ANDREW LACHOWSKY: And part of it is that diverse generation mix. What we experienced this time was a weather event, you know. Droughts occur in the summer that impact hydropower. They also impact steam plant when they're pulling water for cooling from rivers. So that's the type of event that can happen in the summer, and has happened.

So having that diverse fuel mix is a value. Solar during the summer does come at times of peak. So while summer doesn't help -- solar doesn't help in the winter, it can help in the summer, a certain amount of it.

DIRECTOR PFALSER: Thank you.

SECRETARY KEOGH: Director Pfalser?

DIRECTOR PFALSER: What do you think is the best fuel to use for base load generation going forward?

ANDREW LACHOWSKY: Based on economics and availability and with the general expectation that it will continue to be available and low cost, natural gas is the answer.

DIRECTOR PFALSER: Secretary Keogh talked about storage of natural gas, and this might be a guess that's better suited for the natural gas people, but the freezing that happens at the wellhead or -- because of the moisture content, do you know, is this gas dried before it's put in storage?

ANDREW LACHOWSKY: That is not a question I can answer.

DIRECTOR PFALSER: Okay. I didn't know if it would be or not.

And you're -- you were talking about dual-fuel for some of your -- so those are currently natural gas turbine generators?

ANDREW LACHOWSKY: That's correct.

DIRECTOR PFALSER: And you -- what's your second fuel that you use?

ANDREW LACHOWSKY: For one of them, it's diesel. And for the other, it's currently Number 6 heavy fuel.

DIRECTOR PFALSER: Fuel oil? Okay. Have -- has anybody ever used LP gas for replacement in the generation?

ANDREW LACHOWSKY: I'm not aware.

DIRECTOR PFALSER: Okay. All right. Thank you.

SECRETARY KEOGH: Director Bengal?

DIRECTOR BENGAL: A couple things. We've heard about the RTO and their role in determining the energy mix or the ease of reliability of the systems.

What is -- and you may not be able to answer this, but what is their incentive to make decisions based on the questions we keep asking about, reliability of fuel versus economics versus political decisions?

How do they -- how do you think they come about making a determination? That's what we're here about.

ANDREW LACHOWSKY: Well, I do participate with both SPP and MISO meetings so I have maybe some response to that. Let me just say that SPP and MISO both act differently, so I'm going to address them different.

On the MISO side, I have been at board meetings where a MISO board member would say, shouldn't we be concerned about long-term reliability. And a regulator, state regulator, would reply, "That's our purview, so you, MISO, don't be involved with that."

Now, short-term reliability, they do accept that responsibility. And they also have a capacity option. And unfortunately, even their independent market monitors and economists says their capacity market is highly flawed. That is one of the areas that MISO is looking at right now to make some changes.

So right after our February event, they were performing the resource option for the upcoming planning year, which started June 1st. And it cleared really net-zero at MISO. So the signal that that sends is MISO -- MISO, from market participants, is capacity is free. Somebody can come in, you know, municipal -- utility can come and lean on the market and currently capacity is free.

They are looking to make changes to require -- I guess, the most recent change, that no entity can lean exclusively on the capacity option. They at least have to bring 50 of the capacity, meaning ensure that they have enough to meet 50 of their demand.

So that's kind of, you know, MISO's side. And they certainly recognize -- MISO staff is smart. They recognize these are serious issues. They are trying to make other changes, besides the option. They ask for stakeholder input. You know, we provide that input. We make comments, for example, on the capacity option.

So that's the MISO side. They generally take a little bit more -- staff has a little bit more control on the MISO side.

Then we go over to the SPP side. You may hear SPP says, we're stakeholder-driven. We're going to do what the stakeholders want. You know, SPP, the members. So yes, I think they would be more likely to say, we're here coordinating your efforts.

Maybe they've grown a little bit to be a little more independent than that, but that's generally the way they say it, is we're stakeholder-driven and we will do what our members want us to do.

So they have margins that you have to have certain amount of generation resources to meet the needs. They have processes to certify those resources. Winds get up to 10 percent, maybe more, you know, depending on what it's generating at the time of the peaks.

And so that's directionally SPP. They don't tell you, you have to bring a certain type of resource to the mix. They can tell you, you can make it all wind. You can make it all wind and solar to meet your needs.

DIRECTOR BENGAL: Because I've heard -- we've heard testimony and some other comments, our theme -- we've heard our theme here is what's the best base load fuel. Over and over again it's been natural gas. But yet, most of the generating entities when are asked, "what are you building", they're all looking at alternatives.

ANDREW LACHOWSKY: Wind and solar.

DIRECTOR BENGAL: So my point being, if the RTO is having a role in deciding that, the generators are all choosing something different, who brings that together?

ANDREW LACHOWSKY: One of the changes that both SPP and MISO are likely to make is to have a seasonal capacity construct. Everything today is focused on the summertime. And it's -- this event may be a wake-up call and say, hey, we've got to look at the winter. And how does solar perform during in winter and perform during an event.

So I will just repeat, you know, the RTOs both have processes in place where I think they are seriously evaluating making changes.

DIRECTOR BENGAL: Okay. Thank you.

SECRETARY KEOGH: Thank you for your time and, hopefully -- we're short on time so do you have one more question?

DIRECTOR PFALSER: One more. Is that okay?

SECRETARY KEOGH: Sure.

DIRECTOR PFALSER: You mentioned that you were looking at getting permitting for bringing on additional fuel or something. Who would you be looking towards for --

ANDREW LACHOWSKY: Yeah. I appreciate the follow-up. It was no secret I had added that language in there. You know, Arkansas is a great state to live in compared to others, so we appreciate Secretary Keogh and her team has been, you know, extremely cooperative.

But nonetheless, just the idea that you can go and easily permit for dual-fuel for oil, it's not easy these days. So it is the folks here in this office building.

DIRECTOR PFALSER: Thank you.

SECRETARY KEOGH: With respect to the Office of probably in our DQ division, that expeditiously evaluate the -- protectively evaluates those permits, along with having the oversight of the Environmental Protection Agency, so all that comes to play as those decisions are made, as well public input.

So appreciate that and look forward to those applications when they come forward.

I do have just -- I know we want to take a break here, and I know we've got a number of our next special speakers coming up.

Did you have any comments on notification to your customers that you can -- any best practice or any challenges that we could make sure that we address in this report to the governor? Because that was one of his particular focus, is making sure customers were notified.

ANDREW LACHOWSKY: So the serious time frame was the days of February 15th and 16th. And we could already tell from natural gas pricing and availability that Thursday or Friday before, that there were serious issues. So we were telling our 17 distribution co-op members. And I was already getting, you know -- I'm an Entergy customer. I was already getting texts from Entergy to conserve. So it was kind of we were saying, maybe you want to make the same appeal to our members. Each of them does differently.

We also have eight large interruptible customers and I'm responsible for the primary operations. So we were certainly alerting them to pricing, the risk that they could be curtailed. Personally wrote a letter to them the Saturday morning, February 13th, to say, if y'all want to maybe take a vacation this coming week, that would be a convenient thing for you all to do, just kind of alert them that we were seeing pricing and the like that we've never seen, or at least I hadn't seen in my career.

So we were trying to, at least -- this was, I think you can see, this point of view, very costly and at least potentially impact, even for firm load.

DIRECTOR BENGAL: Thank you so much for those that had the choice of turning off power, that probably worked. For those that they had to keep residential power on, unfortunately, it sounds like some of our cities faced high bills, irrespective of that -- because of need to maintain human need. So appreciate that. But thank you for that.

We're going to give the Task Force a seven-minute break instead of 15 minutes. We'll reconvene at 3:00 o'clock and look forward to hearing testimony from Entergy, the Energy Policy Network, Jackson Walker, and PPGMR following our short break. We'll restart at 3:00 o'clock. So thank you so much.

(Whereupon the proceedings were adjourned.)

SECRETARY KEOGH: Today is June 1st, 2021. We are here -- again, we're here today at the Arkansas Department of Energy and Environment headquarters building. We're hearing testimony for the Energy Resources Planning Task Force as convened by Governor Asa Hutchinson.

We went through a series of introductions at the start of this hearing right after lunch. I know we have a few people that have joined us on this. I'll repeat a brief part of --

I'm Becky Keogh, Secretary of the Arkansas Department of Energy and Environment. I have the pleasure of serving on the Task Force with Secretary of Commence, Mike Preston; Director of Oil and Gas Commission, Larry Bengal; and to my, Kevin Pfalser -- or to my far right, Director of Liquified Petroleum Gas Board. To my immediate right is Director Sparks, who is director of the AEDC Existing Business Resources Division, who's sitting in on behalf of Secretary of Commence today for purposes of this hearing.

So with that, like to move forward. I know I mentioned that on March 3rd, Governor Asa Hutchinson signed Executive Order 21-05, establishing the Energy Resources Planning Task Force with the intent of doing somewhat of an after-action assessment, if you will, of the events that occurred in February, identifying lessons learned that will better prepare the state in the event of future extreme weather events or other emergency events that might affect the energy delivery systems in Arkansas.

I mentioned this administration is not -- has experienced, I think, as a system three 100-year events in three years between a flooding event and global pandemic and an ice storm, so we think we're -- well, we're not comfortable with that, but we feel like we're becoming better prepared. And we hope that each of these events have allowed us to put, I guess, the state in a better place for future events.

So with that, I'm going to move forward. Those of you that are joining this afternoon, we'll ask you to come forward in certain order. I'll try to give you warning before I ask you to come forward.

But as I call your organization's name, we'll ask you to come over to this table up here to my right or to your left, let you -- find a place at the table, state your name, title, and organization. That's for, in part, our recording, if anything -- in the event that we just want to make an appropriate record of this discussion.

We would ask that you provide opening remarks or -- up to about five minutes for each of the organizations that are here. If there's multiple speakers, that's fine. But we ask you cumulatively make your comments no more than five minutes. We have Andrea Hopkins here to give you gentle warnings of time and to keep us on track, out of respect for those that are participating.

We also have notetakers over here trying to keep track of the words that you speak today, as well as help us in our report preparation. So after you provide an opening statement or comment, we're happy -- I will turn it to Task Force members to address expeditiously a small set of questions that we developed individually based on our review of your prefiled testimony, which has been very helpful to us. We appreciate the work that went into to provide answers to some questions.

And if you have additional reports, I know the RTOs provided in one case, and I think the second one plans to, a report that they've generated as a result of their own study and assessment of the February event. If you have anything to share with us going forward, we ask that you feel free to notify Troy Deal or staff and others, and we would be able to accept that following these hearings as well.

Again, we're in the process of taking that information and generating a set of recommendations for the governor.

So with that, we've allotted only about 15 minutes for organizations, that Q&A, so we expect that be brief as well. But with that, we'll get started. And I'll ask if a representative from

Entergy can -- or representatives can come forward at this time. We look forward to your comments.

LAURA LANDREAUX: Good afternoon. My name is Laura Landreaux and I'm the president and CEO of Entergy Arkansas.

JOHN BETHEL: Hello. And I'm John Bethel, and I'm the Director of Public Affairs for Entergy Arkansas.

LAURA LANDREAUX: Ready for us?

SECRETARY KEOGH: Sure.

LAURA LANDREAUX: Thank you. It's my pleasure to represent Entergy Arkansas here today before the Energy Resources Planning Task Force. I'll just briefly highlight some of the information that we shared in our responses to the Task Force questionnaire we provided earlier.

The extreme winter weather event during the week of February 15th, 2021, presented challenges at many levels for the State of Arkansas. Fortunately, our electric system performed well and service interruptions were limited in number and duration. Our employees and those of other electric utilities worked tirelessly around the clock to ensure that customers in Arkansas had electric service.

Customer conservation was a key element to addressing the supply and demand in balance. We used a variety of tools to encourage our customers to conserve, including calls, texts, e-mails, broadcast and print media, and social media. Our customers responded to those requests and helped limit the number and duration of outages during winter weather events.

Our diverse fuel mix for electric generation was another key factor in the state's ability to weather the storm. Entergy Arkansas benefits from generating resources that include nuclear, coal, natural gas, hydro, and solar. Without the significant investments to build, acquire, operate, and maintain these generating facilities, the impact of the extreme winter weather would have likely been greater.

Entergy Arkansas will continue placing an emphasis on a diverse mix of resources in an integrated resource plan as the best means to provide safe and reliable electric utility service at reasonable rates, while also providing needed flexibility to respond to extreme weather events and any other imbalance of supply and demand that may arise in the future.

Entergy Arkansas is the largest

transmission owner in the state. We continue to make significant strategic central investments in the transmission system in Arkansas to make it more reliable and resilient. These investments strengthen the system and have helped withstand the challenges presented by the extreme weather conditions and serve to ensure reliable electric service every day. Without the investment to build, operate, maintain, and improve these facilities, the impact of the weather event would have been more significant.

Likewise, we continue to make significant investments in our distribution system. These investments have further strengthened the ability to respond to the challenges presented by the winter weather. Not only have we installed new facilities, we've maintained and upgraded our existing facilities.

We continue to invest in technological improvements that modernize and improve our distribution system. Without these investments to build, operate, maintain, and improve these facilities, the impact of the winter weather event would likely have been more significant.

I'd also like to highlight our investment in advanced meters as a tool that customers will be able to utilize to have more timely information about their usage and can take steps to manage that usage, as well their bills, both of which will be useful during extreme weather events.

As you've heard countless times during the course of the Task Force hearings, the February 2021 weather event caused historically high usage and demand for electricity statewide and throughout the region. Entergy Arkansas' peak demand on February 15th, 2021, was the second-highest monthly winter peak since we joined MISO in 2013. Nine of the top fifteen highest hourly winter peaks since joining MISO came in 2021.

Having high usage and demand during the winter creates additional challenges. During the summer, there is not a competing demand for natural gas for heating. During this event, the demand for natural gas has been high, for both electric generation as well as for heating and other direct uses. Consequently, the winter high demand situation caused real challenges for the industry as a whole. We look forward to working with our peers and MISO on best practice and lessons learned to better prepare for extreme weather events in the future.

Although outages were limited in number and in duration during the event, there were some. Most of the outages for our customers were related to instruction from MISO to interrupt customers to maintain the reliability of the grid.

MISO instructed Entergy Arkansas to interrupt customers on February 16th at 6:59 p.m., with the last customer being restored at 8:59 p.m. The company interrupted approximately 60,000 customers in groups of approximately 20,000 in rolling intermittent outages that lasted between 30 and 45 minutes for any individual customer with an average duration of less than 40 minutes.

To the extent possible, we worked to inform our customers throughout the week regarding the need to conserve, the potential for outages, and in the event of outages, our efforts to restore power. Our investment in a diverse generated fuel mix and the strengthening of our transmission and distribution system helped Entergy Arkansas weather the storm with limited interruptions in service to our customers.

We continue to evaluate the experiences from the February winter weather event and explore opportunities to improve our preparedness, operations, and communications during future extreme weather events.

Thank you, again, for your time, and I'm happy to answer any questions.

SECRETARY KEOGH: Well, thank you for being here and appreciate your time and -- this afternoon.

With your comments, I think it's noteworthy that many of us in this room are customers of Entergy and we appreciate the diligence and the operations and the efforts taken by your employees to keep our lights on as best you could during that time.

But we'd like to kind of turn to the process of the base load discussion we've been having with lots of utility providers this morning. I know what may be unique to you as your availability to deliver power from a nuclear base load plant as well, so can you elaborate on how that benefited you during this event and/or any future plans on how that -- these weather events or winter weather might affect your investment strategy going forward?

LAURA LANDREAUX: I think one of the key things that you heard in our comments and in the prefiled comments is our emphasis on diversification. We made the fortunate decision years ago to invest in Arkansas Nuclear One and the entire River Valley, for that matter. That plant has served this state very well. We received a license extension to continue operating those facilities through 2034 and 2038, I believe. You asked about future plans.

Everything is on the table and we continue to evaluate how those units are performing, continuing to do the required maintenance to keep those facilities tiptop shape, so that when the time comes to determine whether we could -- it would be economic to continue operating those plants and seek a license extension, we've done our due diligence on the operation side to be prepared for that.

So the second part of your question was the performance of the unit during the winter event. They performed exceptionally. One of the units did have a D rate because that was not caused by any operation performance of the system, but external forces in the transmission grid.

SECRETARY KEOGH: That's helpful to know. And I understand those are complicated decisions that you made on a realtime basis going forward.

LAURA LANDREAUX: I would like to note that just from an energy perspective, energy not Entergy, in 2020, the energy provided Arkansas customers was 70 percent from nuclear provider.

SECRETARY KEOGH: I believe during the event, nuclear played a smaller role during those winter weather events. At that time more was coming from other sources, but I do not know if there was anything that affected the ability for the nuclear plant to deliver, should the other alternatives not be available to the grid.

So appreciate those comments and I know that's a -- more of an RTO discussion perhaps than an operational discussion.

With that, I'm going to turn the mic over to Director Sparks first for questions and then we'll move to the other members of the Task Force.

DIRECTOR SPARKS: Thank you, again, for being here. We've heard a lot about diversity. It sounds like you've got a really good mix of things going on right now. I want to change directions just a little bit.

Statewide, nationwide, pretty much worldwide, workforce is an issue. What do you guys see as a future to maintain and continue the workforce that it takes to continue that reliability that you've historically done?

LAURA LANDREAUX: That is an excellent question. We have done a lot. We recognize that the workforce training, workforce development issue is real and it's not just an issue for Entergy Arkansas;

it's an answer issue that faces all of our customers as well.

And so we have invested strongly in technical capabilities with working with the -- with the tech colleges on the one hand, and then most recently, with the State Department of Education to increase the ability for -- for students to take online career education courses going forward.

And so what I would say is that we recognize that it's a real need and we're partnering with the education -- the different education outlets at all different levels to look at ways that we can help facilitate a stronger workforce going forward.

DIRECTOR SPARKS: Thank you.

SECRETARY KEOGH: Direct Pfalser?

DIRECTOR PFALSER: Thank y'all for being here. John, I appreciate visiting with you a couple days ago. And we were talking about nuclear and how important it is and what a great energy source it is.

Is there -- is there any current appetite nationwide to explore more nuclear energy or, you know -- you bring it up and people just thinking, oh, no, it's bad stuff. Sounds like it's a really great fuel to use to generate electricity.

LAURA LANDREAUX: The nuclear facilities

have served Entergy Arkansas customers very well. The issue going forward on investing in new nuclear will always be a cost issue. It's a great resource and whether new nuclear can be cost-effective going forward is something I can't answer today, but it's certainly something we will continue to evaluate as we have invested a great deal, both on the workforce side of it, but also in the facilities and surrounding environment as well.

DIRECTOR PFALSER: What part does regulation play in it being cost-prohibitive?

LAURA LANDREAUX: Cost-prohibitive in terms of investing in a new nuclear facility --

DIRECTOR PFALSER: Yes.

LAURA LANDREAUX: -- or compliance during the operations of an --

DIRECTOR PFALSER: In a new facility.

LAURA LANDREAUX: I don't know the answer to that. But I do know, you know, the equipment costs and start-up costs and the infrastructure cost are significant.

DIRECTOR PFALSER: Okay. Okay.

LAURA LANDREAUX: I don't believe that the regulatory side of it is quite compared to the upfront investment.

DIRECTOR PFALSER: Okay. On your coal-fired generation that you currently have, I know that there are some planned obsolescence going in the future. For those to be maintained as some type of backup, would it just be not an efficient thing to look at?

LAURA LANDREAUX: Not with the current regulatory environment that we have to continue operating those facilities. And so operation, whether it be standby or full-time, I believe, would require the investment and environmental controls on those facilities.

DIRECTOR PFALSER: Scrubbers and those kinds of things?

LAURA LANDREAUX: Correct.

DIRECTOR PFALSER: Okay.

LAURA LANDREAUX: And those facilities are nearing the end of their useful life anyway, so looking at a cost-benefit analysis in terms of making that significant investment to continue the life of those facilities as opposed to taking that same dollar, so to speak, and investing it in newer more efficient technologies that can provide a longer resource for the customers.

DIRECTOR PFALSER: Thank you.

SECRETARY KEOGH: Director Bengal?

DIRECTOR BENGAL: We talked about the role of RTOs in, I guess, working on the future energy mixes and who -- what role each play.

You're a generating company. So as you look forward to replacing capacity, what are you looking at as generating entity?

JASON CARTER: I think from a -- it's a mix of diversity of -- our generating resources is critical, as we've discovered, both in this circumstance and ongoing. So I think going forward it will continue to be a mix of resources.

Obviously, we have nuclear in the mix for several years for certain. We have natural gas that we'll continue to invest in. We have plans to continue to invest in natural gas, also natural gas coal-fired with hydrogen is an option that we're exploring as a future option.

And then we are investing in renewables, particular solar here in Arkansas. And I think we'll continue to do that. We have plans to do that. So we'll continue to have a mix of generating resources, as well generating resources that would be base load that can run all the time, as well as renewable resources that can run, not necessarily all the time, but they can provide a good energy value for our customers and provide a resource that meets our customers' needs.

DIRECTOR BENGAL: Let me ask you a question now. On -- I mean, on a national level, in some states, you know, by the year 2030, 2040, 2050, whatever it is, they talk about going to complete renewable sources of energy. From a reliability standpoint, and not just reliability but from a political context, but agreed reliability, what percentage of the generating capacity in our current transmission systems can be alternative sources versus more reliable fuels?

I mean, how high can it go before we really have to invest a great deal more in our transmission capabilities?

JASON CARTER: I think, you know, we have plans, stated plans, to become net-zero by 2050 or --

LAURA LANDREAUX: It's 2050. It's net-zero carbon by 2050. And so I distinguish that from a pure renewable goal of --

DIRECTOR BENGAL: Right. I agree with that.

LAURA LANDREAUX: That's where we're focusing our efforts. In terms of the capability of the transmission grid, that's probably something that our resource planners are more equipped to answer for you, but I'm certainly happy to follow up with supplemental testimony that can answer that question better than I can today.

DIRECTOR BENGAL: Yeah. I've been reading various things where the alternative sources, the intermittency of those, it's hard for the system to handle some of those as well as the base load.

So how much of your particular load will be wind in ten years?

LAURA LANDREAUX: While we are looking at wind, we're balancing the ability of wind in Arkansas versus out of the state and the deliverability of the out-of-state wind to our system in Arkansas. And so we've -- we have issued a request for proposals for renewable resources that includes solar and wind. And we will evaluate what those opportunities are.

To the best of my knowledge, they are limited in Arkansas and so there will be additional cost to bring that wind into the system here. And we will continue to evaluate whether that's something that the diversification of that resource outweighs the cost, or if it's cost-effective on its own.

But today, we have no wind resources and we haven't planned the system to say we need this percentage of wind or this percentage of X at this point.

DIRECTOR BENGAL: This may be a little difficult question for y'all, but I'll ask it: Does weather affect transmission, extreme temperatures affect transmission lines?

JASON CARTER: Yes. But I don't know that either one of us can tell you exactly how that would happen.

DIRECTOR BENGAL: It reduces their efficiency to transmit, the extreme cold weather would reduce transmission or would it increase it? Does it have any impact at all?

JASON CARTER: I'd probably be better off not answering because I'm not -- not that well-versed in that subject.

DIRECTOR BENGAL: Okay. Thank you.

SECRETARY KEOGH: Thank you, Director Bengal. We'll conclude here. I did want to bring up notification as I mentioned earlier. That's a core focus of the governor.

Just -- and I'll account a personal story. This is not a criticism by any means, so don't take it.

But I know Entergy did a lot in notifying the media through, like, social media texting. And I'll ask this for my neighbors. We were in the first group that was -- that was basically in the rolling blackout, I guess, in that first 45-minute period. It was brief.

But being the first group, the notice that came out to the customers came out about 45 minutes into the following brownout. So for 45 minutes, there was a lot of texting between neighbors, saying, "Do you think this is a rolling?" Or is this, you know, did transformer go down and we need to go find a hotel room. So there was a lot of -- because we were all electric.

I guess the question is, is there something that Entergy is looking at to improve that first notice to make sure that any customer that's affected by a situation, like, that has gotten a direct -- as possible, a direct notice. Because we were all on -- I think we were all, like, on texting programs with Entergy.

So is there anything that could be done to give that customer a realtime notice that this -- what's the nature of the shutdown is, especially during a storm event, not necessarily under extreme weather? I just bring that up as -- so my neighbors will be satisfied.

LAURA LANDREAUX: Absolutely. And I think some of your neighbors were texting me as well. I feel the --

SECRETARY KEOGH: Probably so.

LAURA LANDREAUX: But it's a great question, Secretary Keogh. Let me just start by saying that the time frame from which we learned that MISO was calling for curtailment and the time in which the first curtailment took place was very short.

And the way that Entergy Arkansas prepares for that is through a list of circuits that are essentially turned off, let's use that word, and then turned back on. What we have learned is that there's room for improvement for being able to identify those circuits, the customers on those circuits, and target communications only to those customers, and perhaps taking a cue from what we saw some of the individual co-operatives to be able to do is tell who is next, who is next in line on the circuit.

And that is more of a granular level of communication than we've typically done, but we understand the need to try and make it happen if it's possible.

SECRETARY KEOGH: Well, thank you. I think just a general note that says, hey, we've got this signal from MISO, we're turning, you may be one of those parties, would be helpful. Because I know everybody was looking for the answer, but obviously calling people they knew. So again, thank you for that.

Again, I think the notifications were excellent. That stress was very short-lived and I know that the neighborhood and others in the city appreciate the fact that y'all were so well prepared, that they were minimized to a very brief few hours, I guess, in terms of overall rolling blackout from what I can tell.

So with that, is there any other recommendations you have on notifications that you would like us to -- that we can do as a state to help assist the companies in terms of keeping the public informed?

LAURA LANDREAUX: Communication channels, as long as we continue to share with each other our communication channels perhaps. Our social media and text messages are not the same ones that -- you know, they're not reaching the same audiences as perhaps something the State is issuing.

So sharing those messages over and over and over on the different outlets I think is a helpful and useful tool that we can do together to collaborate on better communication.

I will tell you that communication to customers is top of mind for Entergy Arkansas at all times, not just during weather events. And we're continue to look for ways to improve that. This was an excellent opportunity for us to learn from what we were able to provide and what capability we have going forward to improve that. And we're very much committed to doing so.

SECRETARY KEOGH: Thank you so much. Again, we'll conclude now. And we'll move on, but thank you, again, for appearing. And thank you for all the helpful information you shared. And we'll take that into --

I'm going to ask Energy Policy Network to come forward now. I believe Randy Eminger is here to speak.

RANDY EMINGER: Thank you, Madame Secretary. I'm with the Energy Policy Network. I have with me Mike Nasi with Jackson Walker who's an energy and environmental attorney out of Austin, Texas. And since a lot of this plays around the situation that -- the prime example, but ERCOT, I thought might address a little bit of what took place in Texas to make sure that Arkansas does not head the same direction.

MR. DEAL: There you go.

RANDY EMINGER: A lot of attention has been put around the weather. And of course, the weather did make a big difference in what took place throughout the Midwest. But what's being left out is what took place starting five years ago in both MISO and the Southwest Power Pool.

In MISO over the last five years, they closed 45 base load power plants: 15 natural gas, 9 coal plants, and 1 nuclear power plant. Now, these aren't units. These are power plants. In the last five years, Southwest Power Pool has closed 15 base load power plants: 7 coal, 7 natural gas, and 1 nuclear power plant.

Together both of these RTOs have closed 22000 MW of electric generation in the last five years. 22000 MW of electricity is equal or equivalent to 14 million average electricity used in 14 million homes.

We believe if these power plants had been online, even though there was some problems with some base load plants, we would have been able to sustain this weather event and not had the outages we had in the past.

Part of this is driven by price, as you know, the price of some of the fossil generation and nuclear compared to wind and solar, but part of it is through policies. For instance, the governor of Minnesota who has an executive order out to the Public Service Commission utilities in Minnesota to be 100 percent carbon-free by 2040, not carbon neutral but carbon-free by 2040.

When you have policies in certain states, Michigan, Minnesota, Wisconsin, Illinois, that drive the policies that affect Arkansas, we think the state of Arkansas should be concerned.

One of the primary focuses that I stated earlier is the situation that took place in Texas and ERCOT so I asked Mike if he would fly up and address the council today, the Task Force, a little bit about what's taken place in that state as well. Mike?

MICHAEL NASI: Thank you. It's great to be here. I'm happy to spend to last ten years -- I mean five months of my life in legislative sessions dealing with the aftermath of Winter Storm Uri. I would say y'all's problems are minor by comparison, but it is a cautionary tale worth listening to. Because, frankly, I have worked and very proud to work with Arkansas leadership in several capacities and know very well y'all's fleet and know where you are and where you might be. And it's, frankly, a particularly relevant cautionary tell because Texas' fleet has undergone some changes that Arkansas may undergo. And certainly the time is ripe to be reflecting on those. And as Randy mentioned, those trends in MISO and SPP are worth noting too.

So we filed some comments. I helped Randy and I collaborate. I'm a senior advisor to a group called Life Power, which is a research institute that provided significant amount of input to the document. We provided extra copies that's just blown up graphics, Randy. You know when you file something, they're small and the graphics aren't easy to read. So these are blow-up cartoons.

And these are all elements that were in our testimony, but I just wanted to amplify -- use these to amplify a couple of key points.

So the first is a very busy graphic having to do with what happened in Texas. Again, it's a different situation across a different grid and a different RTO, but there are great similarities in terms of where things might be going in MISO and SPP.

So I won't go through all these to see just how close we came to disaster. I don't think anybody who was without power for four or five days, as my family was, didn't think it was disastrous. But I can assure you as a utility lawyer, we were four minutes from probably the most epic national energy disaster in the history of our county. That's not an overstatement. It's a fact. It's probably the only thing the press got right about the Texas situation, is that we were four minutes away from that.

And what I mean by that is not to, you know, sit here and act like Chicken Little. I, for one, have been complaining and been involved in several advocacy efforts to try to wake Texas up to the shortcoming of our market design. And not glad to have been right, but certainly have lots of things to say in terms of what y'all can learn from it.

The thing that I guess -- I'll move to that next graphic, which is really two charts. To understand what happened in Texas, you really have to appreciate the installed capacity of the Texas grid now is a fill third -- actually more than a third, intermittent.

And you know there was a lot of bantering, political and public press, and a lot of communications campaign dollars were spent trying to say whose fault it was in Texas. Let's be very clear. Multiple resources failed the Texas grid, but the problem started five years ago. It started when we saw a huge attrition of our dispatchable resource and we shifted to a highly intermittent capacity in our grid.

So now we have over 33 percent, really going on 35 percent, intermittent wind and solar. And that performed at an average of about 8 percent of our grid during the storm, and at times during the heart of the storm was at 2 percent. You can't have that much of a falloff in your capacity and not expect to have problems.

Does that mean wind was the only problem or solar was the only problem? No. It was also a very good story about gas, gas supply in particular. And there's a lot of finger-pointing going on about that.

Did gas lose electricity at the wellhead and at the compressor and did that cause the problem? Or was it really about gas not being prepared for the winter and not supplying, you know, gas to the power plants? And the answer is yes, to both.

What we just found out, after a full-body cavity search for five months in Texas legislature, is that everybody in that chain had a hand to play. And there were comprehensive bills passed and we will see significant activity.

But as somebody who truly advocates on behalf of every fuel, I mean, I have power plant clients that build everything: renewable, thermal, nuke, coal. They all have great attributes and they all have, you know, downsides, right.

A just-in-time gas-dependent fleet is a risky fleet. Gas is fantastic, but as a sole dispatchable thermal component of your grid, it is very risky and Texas just proved it. Texas' gas fleet did still have enough to keep the other 20 million people that didn't have power with power alongside coal and nuclear.

But if you really look at the fuel and security that coal and nuclear provide, that is -- I mean, nobody seemed to want to report the story out of Texas because maybe one coal pile at one power plant was frozen. Let me be clear: It wasn't a coal pile. They had coal in a train and it wasn't offloaded into a coal pile.

I've done deep forensic analysis of this situation. And this is a story about how great coal and nuclear are, not the other way around. If you look at those fleet components of the Texas grid, you will see winter resilience that is very impressive.

What's the best testament to that? Texas legislature just passed in the Senate Bill 3 a comprehensive market reform directed to its public utility commission. And in that component, they have directed the commission to create a special seasonal operating reserve that will be a new product in the ERCOT market. And fuel storage, that which you see in nuclear and coal power, and if you actually have gas storage on-site, is actually a requirement of that part of the market reform.

So that is the best testimony as to what our leadership decided to do. And remember, a state that is really well known as an oil and gas state, not necessarily a coal or nuke state, just said coal and nuke are a big part of what our fleet should look like.

So that's the cautionary tale. And perhaps we'll see as these things get implemented what their success is. And our graphics point this out. I know you guys are trying to keep things moving so I won't keep on going on.

But the thing I will say as someone who cares about Arkansas and done a lot of work here, just don't let decisions about perceived obsolescence drive an attrition of your base load capacity. A lot of things go into evaluating whether a coal-fired power plant is at the end of its useful life.

A unit that can be retrofitted with additional environmental controls seems like a big capital expense at the time. I can assure you every Texas unit that invested in those controls adding to its remaining useful life was pretty happy they had those power plants this winter.

And those that retired -- and we did. We lost 6000 MW of coal in six years. You put those units back into our grid, we might have had three hours of outages. Okay. That analysis is contained in our testimony. That's not speculation. If you run the numbers EIA, ERCOT, you add back that capacity.

People say, what about winterization? Again, other than a couple of unique things that happened that you don't expect to happen in coal at nuke plants, that part of the fleet was not affected by the significant winterization issues that we saw in a gas supply.

Doesn't make gas a bad fuel. Doesn't make gas a bad part of a thermal dispatchable fleet. But as a sole component, it is a very dangerous business to think that the future of America should be built on the shoulders of a thermal fleet dependent on gas versus the other diverse resources available to it in Arkansas.

Certainly, it is very well situated right now. And our graphics point out that it may be heading in a direction that is more concerning. And certainly, MISO and SPP are heading in a direction that's most disconcerting.

And the last thing I'll say about MISO, for example, they put a very Prussian report last year. And they have a graphic that's in our materials in one of our blow-ups here, that says once you get past 30 percent on intermittent resources, you start to see significant system disruption. They were putting it out as a cautionary perspective analysis.

Quite not an accident that Texas had what it had happen in this storm when it passed that 30 percent threshold. It's not an accident. It's not a coincidence. It's because when you have that kind of intermittent that's weather dependent, these events, not even unprecedented events can significantly impact your ability to deliver fuel -- I mean, to deliver electricity in a reliable way.

So we've left with some recommendations that we certainly don't purport to say what Arkansas should and should not do, but the ideas that, I think, are worth considering are -- are ideas that Arkansas should be standing up within its role at SPP and MISO. Those executives will tell you, we are policy takers, not policymakers.

Those RTO have to have states express what their policy priorities are. I can tell you that renewable portfolio standards that states pass have to be, you know, absorbed into their market rules. We should be passing reliability standards across the entire Midwest and the South so that reliability as an ethic, reliability as a state policy, must be integrated into what SPP and MISO are doing.

I'm not saying those entities aren't looking toward that. But they're not having to absorb them as state policies explicitly as renewable standards and that could change.

So that, along with just making sure you value those thermal resources you already have and be very wary about retirement decisions. Because environmental law is a major component of my practice. It can be complied with, with a coal plant.

You just actually have to strategize and invest in the coal plant and make sure it has a useful life that fits up with the reliability needs of your state. And we certainly recommend Arkansas taking a very jaundiced view of any retirement in the wake of this storm. So thank you.

SECRETARY KEOGH: Thank you for both being here today and providing your perspective, and especially our neighbor with the same challenges. I know that we were pleasantly surprised that Arkansas is in a better shape than Texas for our citizens, but we understood that we're part of a region that relies on many Texas industries and operations. And as a result, we know our marketplaces were dramatically affected due to the cost that they suffered.

So we appreciate that. I know from a commerce standpoint, we can't look at ourselves with hard walls around us, nor do we look at Oklahoma differently than that either. So I appreciate my counterparts and their interaction, making sure that we were all talking to each other, and making sure that things, information we could share with each other was helpful and helped support continuing operation.

I guess the question, you raise a number key issues, some of which we can probably address today and some of which may be beyond the scope of the recommendations of this report. But I guess I would just -- we talked about base load and we talked about the role of nuclear. You mentioned that.

I know in Arkansas we have several -- we probably have one of the recent coal investments in the country in terms of a facility that's very clean operating, but how do we look at storage as a key component?

We've heard some testimony this morning about natural gas storage and its value and perhaps disinvestments that occurred due to the low price of gas. Is that -- does that play into your recommendations, in terms of if gas is going to be part of the equation, natural gas, particularly as we deal with intermittent sources, you know, relying on perhaps gas along with these other base loads, it -- do you see storage as a key component of that pricing structure for the RTO to consider?

MICHAEL NASI: Yeah. I mean, it is. And just to be clear, the -- part of the Texas legislature response does include that aspect too.

Because, I mean, we have to acknowledge that gas is a big part of our fleet already and it's going to be. And if intermittent resources are going to grow, it's going to continue to be a critical one, right.

And so especially in a quick-start capacity, it's the best technology we have. So gas storage is all about geology and economics, right. You don't necessarily have favorable geology where you located your resources and so -- your generation resources.

Siting criteria for new natural gas quick-start and base load units, probably ought to be factoring in gas storage capability and certainly put priority and maybe even create economic incentives to do so. Texas is definitely going to take a baby step in that direction with these market reforms and see whether that serves as a benefit.

You mentioned the pricing can undercut it. Yeah. I mean, super low natural gas prices -- and there are a lot of things that impact that, have a lot to do with why people don't invest in that. And the lack of a price signal in the power market is one of the reasons why gas storage is not economic.

And so making sure you have better signals for thermal generation will bring about more executive favorability to gas storage. Making sure you have seasonal products in these marketplaces that value fuel storage can also bring the economics in line.

But you still also have to have the geology. Because if you've got a long pipeline between the gas storage facility and the power plant, you haven't helped yourself a whole lot, if you've got some disruptions issues. We're just talking about the winter. Not talking about terrorism. Not talking about all the other things that could affect pipes.

So again, all of the above. It sounds -- sounds trite, but it's a very real energy policy priority. And as far as storage, I don't know if you meant to go into battery storage, but we have a component of our testimony on that and Light Power has a battery expert that has submitted some observations in here. I won't repeat it. And I didn't stay at a Holiday Inn Express last night so I won't act like a physicist.

But he has some very insightful thoughts about what he's -- he's bullish about storage but he's extremely skeptical about overreliance on utility-scale storage as any kind of meaningful component of our grid moving forward because of economics and a pesky little thing called the periodic table. So I do recommend reviewing that testimony. It's quite persuasive.

SECRETARY KEOGH: Thank you very much. I'm going to turn to Director Sparks to follow up with questions.

DIRECTOR SPARKS: Thank you. And thank you for that information. That was great information.

You mentioned as a source as the mix becomes greater than 30 percent intermittent, things become kind of maybe unstable, maybe not like you really like to have them.

Is there is a sweet spot? What's that sweet spot for intermittent?

MICHAEL NASI: Great question. And I do think that the ability to bring about power -- battery storage can allow that kind of penetration to be more functional. Beyond that, what MISO is observing is weather dependence just swings things too significantly.

There's a term, and it's a little wonky, but for a utility geek like me, it's every day. And that's called net load. Net load variability is a huge problem. It is the price driver in the ERCOT market. And nobody ever would have thought the highest price in electricity isn't when demand is highest. It's when your demand is strong and the weather changes quickly.

Because even if we're off by just a little bit in forecasting wind and forecasting when wind is going to pick up and whether there's going to be clouds and the end of the day when our solar drops off.

If you look at even in -- it's like God has a sense of humor. Because while we were debating the bill in the legislature, we had serious price spikes throughout the shoulder months in Texas, which is a time of -- I'm not a native Texan, but the one time you want to be there, right, because the weather is nice.

But we had clouds right before dark so the solar dropped more than we thought. And it wasn't that windy, at least it wasn't as windy as they thought it was going to be. And just those little blips on a third of your grid can swing the price of electricity very high.

So there's a lot of economics and weather and other issues that factor into that penetration estimate. But the experts have fleshed out that

that's really where you get to see this, where you start seeing this extreme volatility and there's not a whole lot we can do.

The forecasting -- our forecasting has gotten a lot better, but a bank of clouds in the wrong place in the wrong part of the state or the system and then a little bit of a lag in a low pressure system and you've got a problem. And that's happening almost every month in Texas. And I'm not looking forward to the summer. In fact, I might come see Randy up here in Arkansas quite a bit.

SECRETARY KEOGH: We hope you enjoy Arkansas this summer. Director Pfalser?

DIRECTOR PFALSER: Yes. Just wanted to address the three warnings signs that you shared with us.

First one, existing base load is found and generation should remain in operating reserve. You heard the conversation just prior to y'all stepping up here with Entergy. And in one of their plans, there should be a financial incentive to the utilities.

MICHAEL NASI: Right.

DIRECTOR PFALSER: Where do you see that incentive coming from in -- I mean, would that be through a tax break situation or what --

MICHAEL NASI: It's highly dependent on both the state policy and the market rules of the grid, right. So in the ERCOT grid in the rough business of the energy-only market, that's going to have to come in the form of a market reform that better values a winter reserve, right.

In a regulated market like Entergy is a part of in the state, the state can provide, you know, a different kind of cost recovery mechanism. It could provide, you know, state taxes. I've done a lot of work on carbon capture utilization storage incentives. There's a lot of levers the state can pull to make those kinds of things better value.

And then I do believe that -- and it kind of relates to the second item, that the State of Arkansas can advocate in its role within the MISO and SPP grids, that thermal resources, especially winter fuel and secure thermal resources, should be valued better by the market rules.

And there's this concept call firming and it is the idea that if you're going to have an intermittent component to your fleet, you need to actually have dispatchable thermal to back it up, and that you can't just rely upon the grid somehow magically making that happen.

I don't think that's a failing of Entergy right now. I think if Entergy's thermal fleet, thermal dispatchable fleet thins out, that would be a different question, but certainly that's not what they've announced.

The question really is, you know, if the cost of environmental controls and the risk -- and it's no secret, Randy and I have been part of groups that have been fighting to keep those plants open. Because, you know, once you retire a unit, it's gone forever. And not just the jobs of the power plant, but the ability to actually leverage the capital and the used car that you've already paid for, right.

So what the economics -- where the economics make sense, I'm a big believer that environmental controls are worth the investment. They seem expensive at the, so do new plants when you build them new. But to the deliver low-cost energy year-round 24/7 and that I think those decisions have to be scrutinized very closely.

And I think that what the state does through regulatory carrot sticks, there should be a hard look at that kind of component in your fleet.

DIRECTOR PFALSER: You touched on the

second one just briefly there, back the purchase power contract with base load, if they have intermittent. So what would that contract be between?

MICHAEL NASI: Well, it depends on the market, right. So in Texas, they're going to try this out. In the ERCOT market, it's going to have to be between the ERCOT as the dispatch agent of the state will be -- they do already have what's called ancillary services in these markets. Okay.

So market participants load customers, right -- right now, have to pay ancillary services to make sure the grid stays reliable. So these markets hold back a certain component of thermal quick start gas, for example. And everybody pays for that component.

What we're finding is that ancillary service component is getting more expensive because we're having more and more intermittent energy and customers maybe shouldn't be the one paying for it.

Because if a generator -- if a thermal, coal, nuke, or gas generator says he's going to be there and gets paid to dispatch and then doesn't, they have to replace their energy at the cost of the market. That's why you see multiple bankrupt entities in Texas right now, and many of them are generators because their resources didn't show up and they had to actually replace it at 9000.

That is not what happens to renewable energy providers. They participate in the market in a different way. Does it mean they should have to bid into a day-ahead market and have the same consequences? No. But it should be some kind of balancing. And the idea of firming would require that intermittent resource generator to procure some type of contract, either independently or build its own battery storage, for example, or contract with the actual RTO for ancillary services and a market product that is being competed for, so it's dispatchable, right.

So this is not going to get solved by wind and solar saying we're going to build batteries. It can't. And you've already heard testimony so I won't retrace that, and we've submitted stuff.

But there's really not a thermal dispatchable ancillary service market, a robust one yet. And we need -- we need one. And we need -- that cost cannot just be shouldered by customers, but by the people that are actually imparting the intermittent penalty on the system.

Doesn't mean that all that cost goes to renewable. Needs to be distributed on what's called a cost causation basis. And that's what ERCOT is going to be relying -- looking at. And Texas is going to have probably the leading edge of the envelope experiment on this and we'll see how it turns out.

DIRECTOR PFALSER: And they did that through legislation?

MICHAEL NASI: They did.

DIRECTOR PFALSER: Okay. Do they have a similar entity to PSC Arkansas?

MICHAEL NASI: They do.

DIRECTOR PFALSER: Could that have been promulgated through the rules --

MICHAEL NASI: They actually could. They could have done without legislation. I think those PSC commissioners who are appointed, not elected, love it when the legislature gives them a little air cover, so they have provided that.

But actually, I think most PSC and PUCs across the country have the kind of ability to provide that kind of market product. I don't think it takes legislative action. I think it's a good idea, so that you've got good democratic support behind the idea.

And believe me, there was a much more strident proposal in the legislature that actually did come out of the Senate in Texas that would have absolutely required all intermittent resources to back up all of their intermittent, but that was softened to more of a, let's do it on a cost causation basis and let PUC figure out what that percentage should be. So that will play out at the agency there and I do think that it's a product that other markets are going to want to look at moving forward.

DIRECTOR PFALSER: Thank you.

SECRETARY KEOGH: A lot of information there. Thank you, Mike. And I'll turn to Director Bengal for follow-up.

DIRECTOR BENGAL: We talked about defining base load. Looking from your charts, that you had defined base load as simply on-call fuels, in other words, generating capacity that would be on-call: coal, gas, nuclear, all of those sources.

Given that and looking at your warning sign handout, you talked about the RTO being directed to place a priority on safety and security of Arkansas. And assume you're referring to doing that by having adequate base load.

Now looking at your other charts, it looks like the RTOs are not doing that because 50 percent is going to be wind. So why is that?

MICHAEL NASI: Yeah. So that's really the whole -- you've got to the essence of our testimony, right, both in the prefiled and graphics that I provided.

We are in good shape in Arkansas right now. But we're heading in a direction because we're interconnected with SPP and MISO, that's going to look a lot like ERCOT four or five or six years.

DIRECTOR BENGAL: What's driving that?

MICHAEL NASI: It's totally driven by the influence of production tax credit, investment tax credits for wind and solar. So tax policy makes those investments very favorable to the investors. And policy in states.

I mean, Randy started off our testimony, right, with the discussion of Minnesota's policy. So that really goes to the heart of, you have multiple states that have, say, a lower priority on reliability, you would argue from -- by inference from their action than maybe Arkansas.

So when I said the RTOs, SPP and MISO, are policy takers, that's part of that recommendation, is let's make sure states like Arkansas, all the way from the Midwest, are passing state policies and making actions and directing their commission to represent the state in those RTOs with a prioritization of dispatchability so we can, again, not stop the growth of renewable energy. That's not the goal; it's to ensure reliability.

And so let's be a little bit more cautious about it. I mean, when you look at this map, you look to the future of both MISO and SPP; it's a little scary given what we just experienced.

DIRECTOR BENGAL: Given it's a multistate --

MICHAEL NASI: It is.

DIRECTOR BENGAL: -- entity?

MICHAEL NASI: It is.

DIRECTOR BENGAL: Multistate legislature.

MICHAEL NASI: Right.

DIRECTOR BENGAL: All of which have different viewpoints on politics of energy.

MICHAEL NASI: Right.

DIRECTOR BENGAL: How do we even bring that about?

MICHAEL NASI: It's one --

DIRECTOR BENGAL: Given the state --

MICHAEL NASI: It is the hardest nut we're going to have to crack in the next ten years.

DIRECTOR BENGAL: Is that --

MICHAEL NASI: I said that in my --

DIRECTOR BENGAL: -- base on that --

RANDY EMINGER: It is minimum, is that every state at least is setting a policy of what's important to them and then collaborating with like-minded states to build coalitions at these RTOs. That's what renewable-driven portfolios and advocates have done and that's what reliability advocates should do.

It is not a situation that is one that we wanted to get into, but it's the reality. So whether it's North Dakota, Nebraska, Oklahoma. I mean, Oklahoma's governor, I didn't talk about it, made a pretty strong statement about how that oil and gas state felt about coal, which was that it saved it, right.

And so they're a lot of states that care about these issues like Arkansas does. And if enough of them do it and we -- an interstate compact is a fascinating concept, just the first step, having states actually take some action and have their representatives on those boards express what the states values will have an effect. And frankly, the executives of SPP and MISO have said as much.

DIRECTOR BENGAL: Thank you.

SECRETARY KEOGH: Thank you, Director Bengal. Thank you for being here today with your testimony and appreciate your time.

I know that our governor works closely with the governors of Oklahoma and Texas and is in key conversation with -- about energy policy. And I appreciate that we are, like -- we are oil and gas states, I guess.

But I know that we know and I've heard statements that we are committed to modernizing our fleets and looking at all -- all of the above technologies. So hopefully we can learn from this process and make sure that we do keep those thermal investments there to back up the intermittency of the renewable fleet as needed for reliability.

So I think Oklahoma's governor, if you recall him saying that they're renewable because of their natural gas supply. That's -- that's not the other way around.

So anyway, with that, we'll move forward to our next presenter, I guess, at this point. I would like to ask PPGMR representative to come forward. And we'll listen to your opening comment after your introduction and have a few questions for you. Thank you.

JOHN PIESERICH: Thank you, Secretary. My name is John Pieserich. I may be loud enough you can hear me anyway.

My name is John Pieserich. I'm here on behalf of PPGMR. We are a private law firm here in Little Rock focusing on regulated industries. We represent a wide variety of industrial activities from power plants to pipelines to natural gas producers, and have appeared in front of Secretary Keogh, Director Bengal over the years, in my case for more than 20 years now. And we sit in sort of a unique spot.

My comments today are my own and shouldn't be taken to reflect any of the clients. Because when we were asked to do this, it's something where we thought it was important to have independent commentary.

When we were asked to do this, we were asked to prefile testimony, which we did. In addition to that, I also wanted to talk a little bit about something where we could actually get a benefit.

Because we represent this variety of different industries, we try to find some things, in addition to the electric utilities, where they can all have a common benefit. One of the things Texas is doing, I'm also licensed in Texas, they have the Texas Disaster Act of 1975.

Arkansas would be benefited from a similar authority to relieve electric generation facilities, along with other industries, from strict compliance with the various Pollution Control and Ecology Commission rules during disaster events. It can be any type of disaster event.

Arkansas has good experience dealing with disaster events. And Secretary Keogh, through the division now of the economic -- excuse me, I am going to call it DEQ until the day I die, so --

SECRETARY KEOGH: That's okay.

JOHN PIESERICH: So DEQ --

DIRECTOR BENGAL: It still is.

SECRETARY KEOGH: It still is DEQ.

DIRECTOR BENGAL: Just division instead of department.

JOHN PIESERICH: Yeah. Division, not department.

Arkansas can -- if you are predominantly community, you -- after we have a big winter storm or a tornado, you can come to the state of Arkansas and ask the Director for permission to open burn vegetative debris. You can set up your incinerator and actually move forward without having to get that permit. And so Arkansas has a good practice of understanding how to deal with these events.

The Texas Disaster Act of 1975 has similar language in it. And I think Arkansas would be well suited and well benefited by a similar statutory flexibility that we can find there.

The Disaster Act of 1975 is found in government code Chapter 48 as part of their mercy management provisions. And it provides that once the governor executes an executive order or proclamation that the disaster has occurred or is imminent, then he can allow certain things to go unrequired. He can alleviate certain obligations.

It only continues as long as the disaster is ongoing and, unless renewed, cannot stay in place for more than 30 days. So it's not like we would be asking to give a long-term pass. And even the pass that's allowed in Texas is not an absolute pass.

It is, for example, a regulatory

requirement that you file certain paperwork for a registration, for instance. You can just get more time. They still expect you to do it. You still have to comply with the obligation. But instead of having to do it in the midst of an emergency, you can do it later in time.

It has to also strike a balance between whether strict compliance would cause or hinder you in coping with the disaster. If it's something that you can do and it's not going to cause you any trouble, the State of Texas expects you to go ahead and do it.

If it's something that's going to cause you trouble, for example, you have an air emission control device at a manufacturing facility that requires it to be in operation or else you can't operate your emitting source and that device goes down because of cold weather, it may freeze up because the gas supply going into it, then you could waive that obligation and continue to operate.

So if you're a power plant and you have an emitting source, like a coal facility, that has air emission controls or has monitoring that's required and continued monitoring, for example, you would be able to waive that obligation until such time as the emergency had passed and then do your repair, where you weren't taken offline where it was going to endanger human health and the environment.

During the February winter weather event, Texas Governor Greg Abbott declared a state of emergency for all 254 counties, and they implemented this. It allowed 50 -- I'm sorry, allowed 15 chapters of the TCEQ rules to be suspended and it gave them flexibility they need to be able to respond to a disaster event.

And I would propose that it would be important for Arkansas to have a similar opportunity. They actually have the entire list of suspension that involves things from public accounts, health and human services, TCQ, railroad commission, Department of Housing, motor vehicles, the Board of Plumbing Amateurs. It's a wide-reaching thing. I believe that Arkansas would be benefited similarly.

And I realize I haven't talked at all about my prefiled testimony, but I thought this was much more important from a practical thing that maybe we could enact and get some benefit from. I thought maybe you would appreciate a different viewpoint today.

SECRETARY KEOGH: That's very helpful. And we appreciate the fact that you expanded on your prefiled testimony. That's exactly the purpose of the testimony today.

So with that, I'm going to ask each of the Task Force members if they have questions. I think I'll wrap it up at the very end. I'll immediately turn to the Director Sparks and let him ask any questions.

DIRECTOR SPARKS: I think I'll pass at this time.

SECRETARY KEOGH: Direct Pfalser, are you ready? We moved quickly to you.

DIRECTOR PFALSER: Very quickly. We were speaking earlier. And so you represent your clientele as opposed to directly working in the industry. What, as far as the foreseeable future, with everything you have to have deal with, what -- what base load generation should we be looking at?

JOHN PIESERICH: So you have to have a fuel mix. It's the same answer you're going to hear from everybody else.

The interesting thing is, sitting in my position, I don't have to worry about the economics. From an economics perspective, the natural gas is clearly the best fuel. When you have to capture all those things, the bigger issue that we have is we have other types of facilities, be it hydro, be it nuke facilities, that would all provide tremendous benefits across the board, but are almost impossible to permit.

When we come to DEQ for permits, we view it as we're entitled to a permit, as opposed to if you go do FERC or you go to other federal facilities, federal regulatory committees, you, frankly, may spend 10 or 15 years just trying to get a permit for a nuke facility, for example. The permitting process is so complicated, it's daunting.

DIRECTOR PFALSER: Okay. Thank you.

JOHN PIESERICH: Yes, sir.

SECRETARY KEOGH: Director Bengal, do you have any questions?

DIRECTOR BENGAL: Thank you, John, for coming. You know, I did have a question but I was sitting here in anticipation of having more time for Kevin's questions and I forgot.

JOHN PIESERICH: I'll take a pass any time.

SECRETARY KEOGH: You'll take a pass any time.

DIRECTOR BENGAL: No. I don't have any

questions.

SECRETARY KEOGH: Well, thank you, John. You said you represented a diverse group of clients. And I guess, do you have any recommendation -- if you have any specific recommendations beyond, you know, what would've said today but also this other, we appreciate you following up with us on those items.

And as I mentioned, notification is an important concept that we want to address. If any of your clients have perspective on that, I would appreciate some feedback on how -- how to make those recommendations real, especially what role we can -- we need to play in terms of our policymaking or recommendations for any kind of requirements or minimum requirements.

Secondly, was -- I guess, just the overall aspect of how we deliver the power sector, you know, in the state, how we support the market-based strategy that we've been supportive of, but then how do we balance that with the importance of cost and reliability and environment, as we make those decisions.

So just appreciate you're being here today. And I don't have another question for you, but I just wanted to urge you to continue to stay in touch with us and provide us those specific helpful recommendations as we go forward.

JOHN PIESERICH: Yes, ma'am. Well, thank you.

SECRETARY KEOGH: All right. With that, this concludes, I guess, our hearing for this afternoon a few minutes early. Look forward to some hearings tomorrow with the liquified petroleum entities and a few follow-up on a few utilities that could not be present today.

So we appreciate your time today. Please feel free to watch tomorrow's proceedings, if you're interested and/or we can make a recording available through linkage by connecting with Troy in the future. So if that's something helpful to you, as you have your own conversations in your own organizations, for Arkansas' benefit, we are happy to share that with you.

Thank you so much for being here and being part of this process.

(Whereupon the proceedings were adjourned.)

REPORTER'S CERTIFICATE

STATE OF ARKANSAS)
) Ss:
COUNTY OF PULASKI)

I, KARISA J. EKENSEAIR, Certified Court Reporter, Registered Professional Reporter in and for the State of Arkansas, do hereby certify that the proceedings were taken by me in stenotype and was thereafter reduced to typewritten form by me or under my direction and supervision; that the foregoing transcript is a true and accurate record of the testimony given to the best of my understanding and ability.

I FURTHER CERTIFY that I am neither counsel for, related to, nor employed by any of the parties to the action in which this proceeding was taken; and, further, that I am not a relative or employee of any attorney or counsel employed by the parties hereto, nor financially interested, or otherwise, in the outcome of this action; and that I have no contract with the parties, attorneys or persons with an interest in the action that affects or has a substantial tendency to affect impartiality, that requires me to relinquish control of an original deposition transcript or copies of the transcript before it is certified and delivered to the custodial attorney, or that requires me to provide any service not made available to all parties to the action.

IN ACCORDANCE with Rule 30(e) of the Rules of Civil Procedure, review of the transcript was not requested.

GIVEN UNDER MY HAND and SEAL OF OFFICE on this 15th day of June, 2021.

KARISA EKENSEAIR ARKANSAS SUPREME COURT NO. 802 CERTIFIED COURT REPORTER

KARISA EKENSEAIR
Notary Public - Arkansas
Pulaski County
My Commission Expires 06-18-2028
Commission # 12704567

Karisa Ekenseair, CCR, RPR LS #802
Notary Public in and for
Pulaski County, Arkansas
Commission No. 12704567
Exp. 06-18-2028

AR Energy Resources Planning Task Force

June 1, 2021

Black Hills Energy
Ready

Overview

We are a customer focused, growth-oriented utility company with a tradition of improving life with energy and a vision to be the energy partner of choice. Based in Rapid City, South Dakota, the company serves 1.28 million natural gas and electric utility customers in eight states: Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming.

Gas Utilities

Arkansas
Colorado
Iowa
Kansas
Nebraska
Wyoming*

Electric Utilities

South Dakota
Colorado
Wyoming*

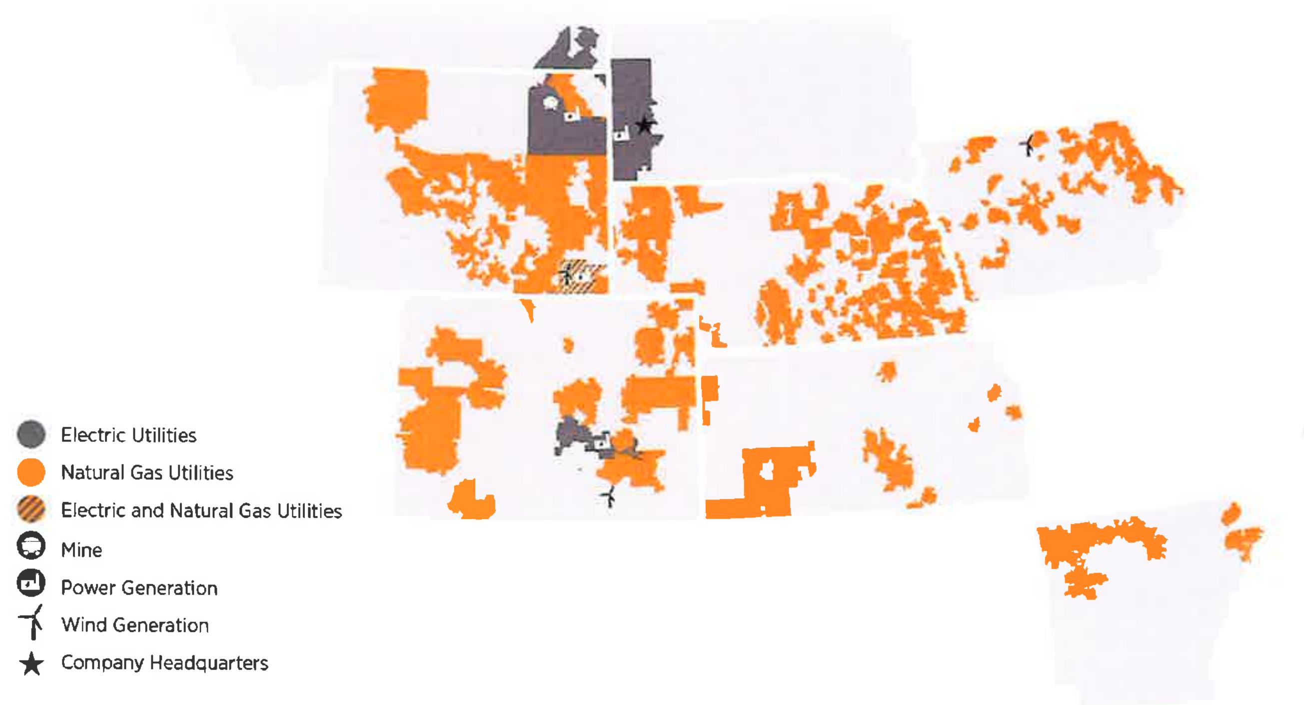
*Utility supplies electric and gas service to Cheyenne, Wyoming and vicinity and gas service to northeast and northwest Wyoming

Power Generation

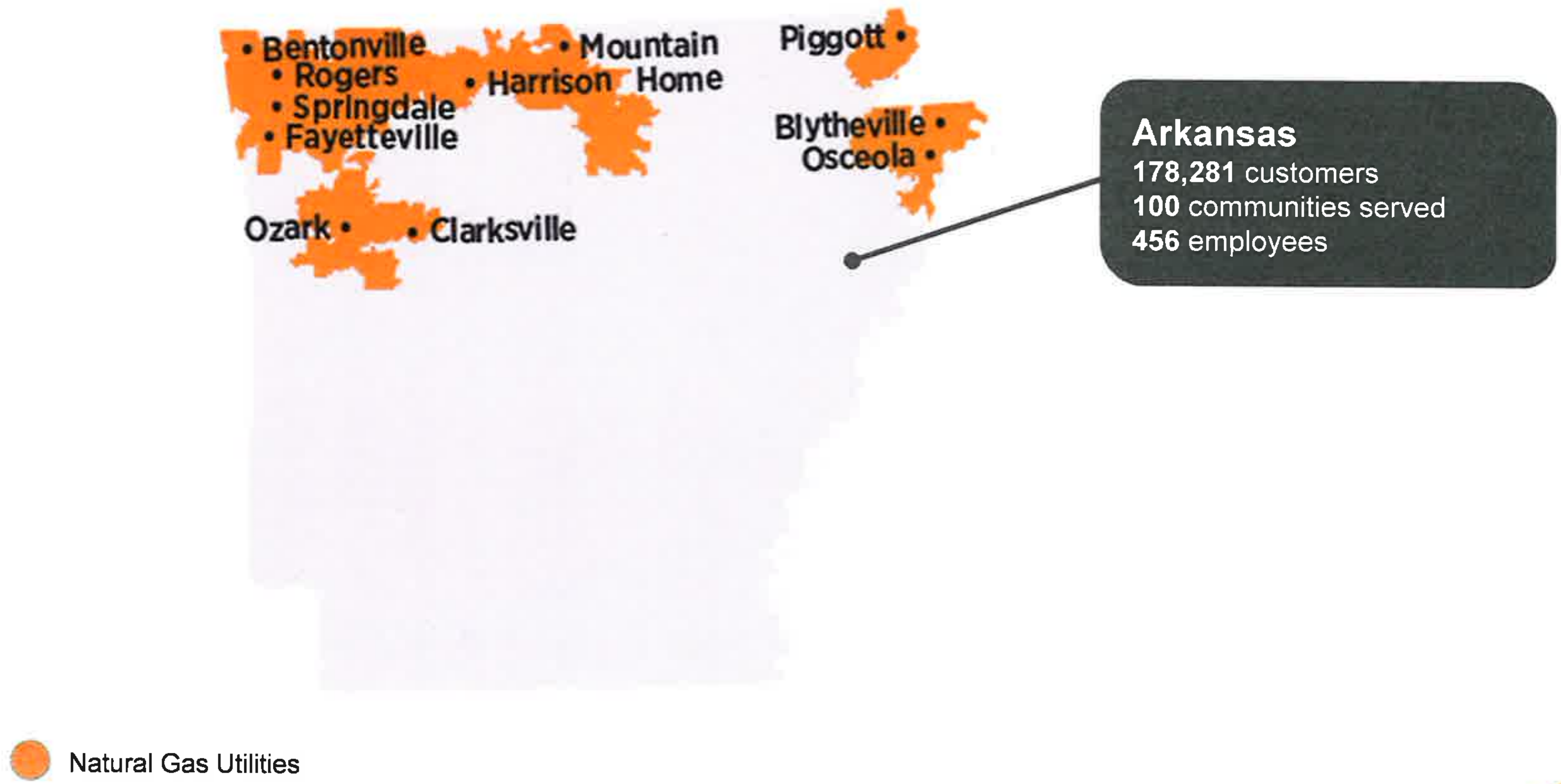
Black Hills Electric Generation

Mining

Wyodak Resources



Black Hills Energy – Arkansas Gas



6 - Am

CenterPoint Energy

Gas Supply Overview

Arkansas Energy Task Force

NOT PUBLIC DOCUMENT – NOT FOR PUBLIC DISCLOSURE

Miles Kenny
Vice President Gas Supply

June 1, 2021

NOT Speculative Traders

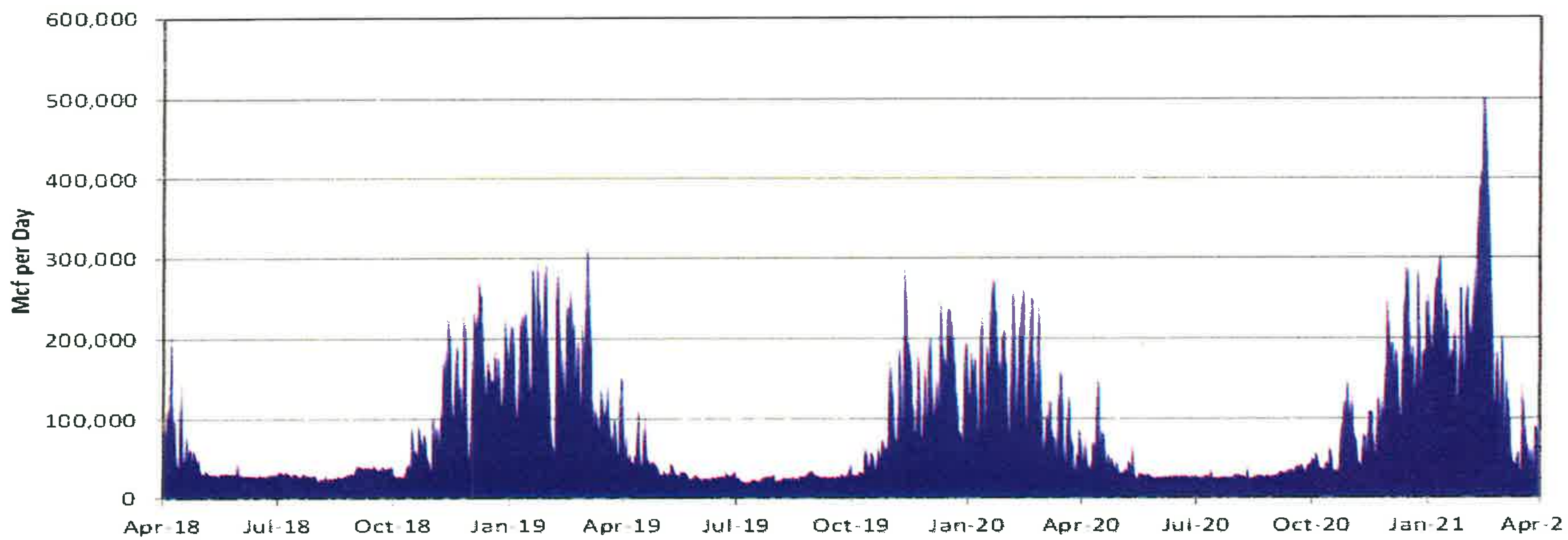
CenterPoint® Energy

We are NOT Natural Gas Traders, only Buyers!

Extreme Warm to Extreme Cold

- This chart represents 3 years of daily load patterns in Arkansas.
- This demonstrates the wide swings in customer demand that require a flexible portfolio.

Example of Arkansas Division Daily R&C Gas Purchase Pattern



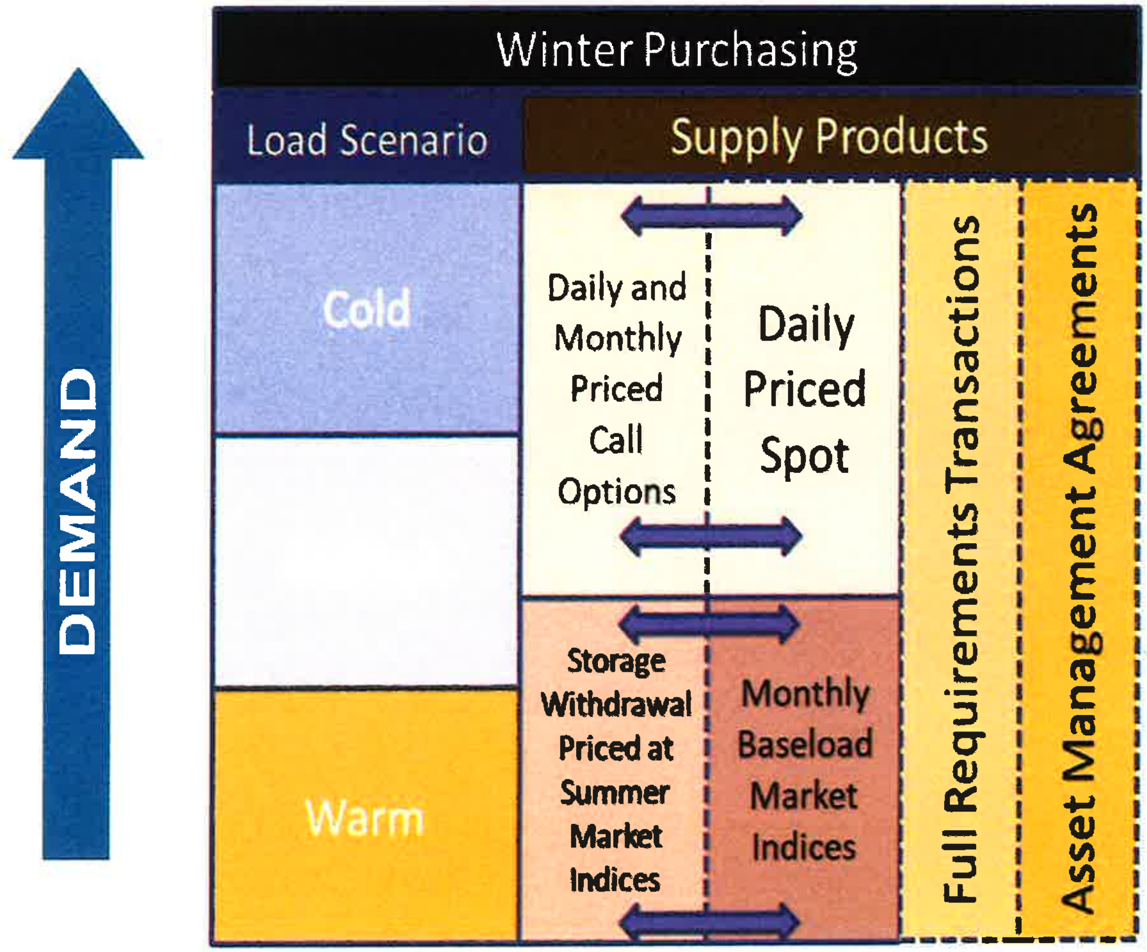
Gas Supply - High Level Strategy

Diversified portfolio

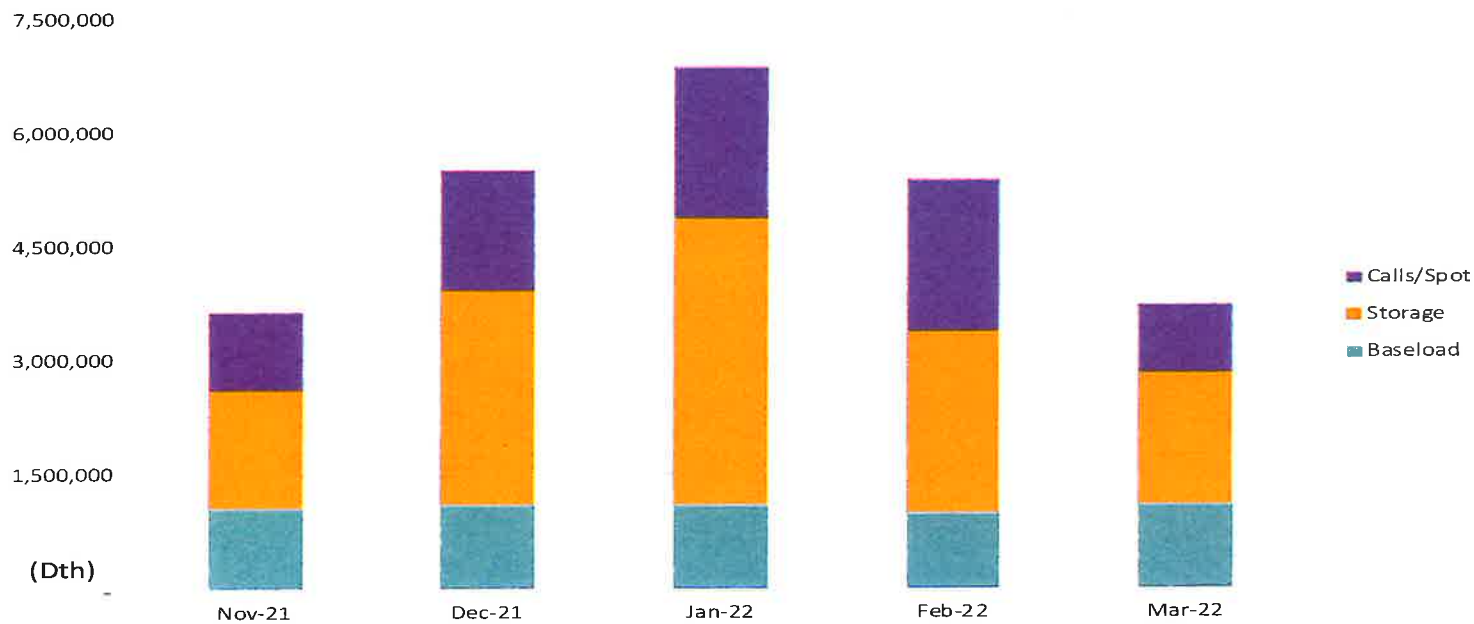
- Physical supply products
- Pricing structures

Balanced portfolio

- Reliability
- Reduced price volatility
- Reasonable priced



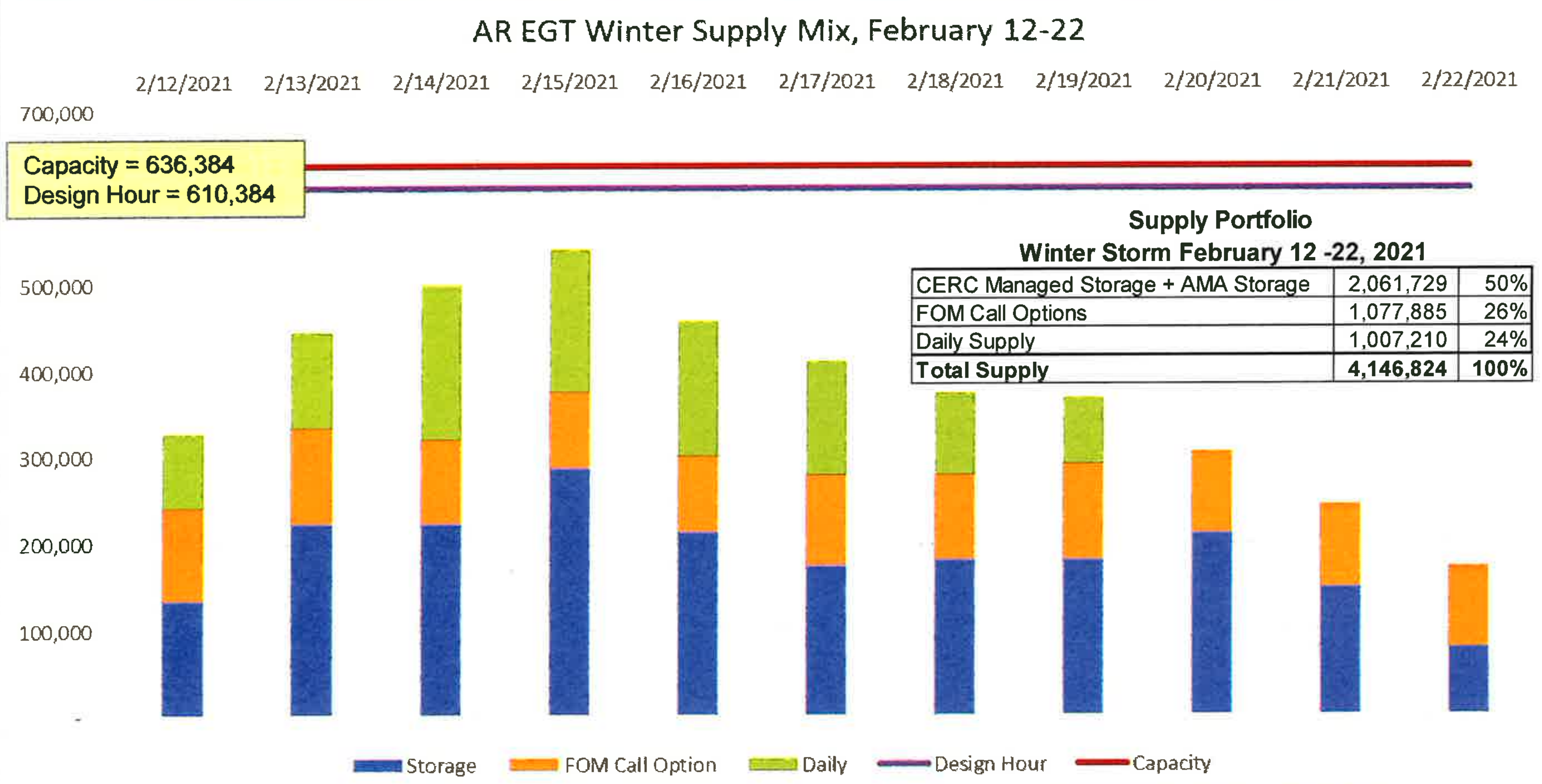
Plan: "Normal" Winter Supply & Demand



	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Total
Calls/Spot	1,023,972	1,599,495	1,997,424	1,997,766	902,657	7,521,314
Storage	1,562,028	2,825,505	3,788,576	2,393,234	1,728,343	12,297,686
Baseload	1,050,000	1,085,000	1,085,000	980,000	1,085,000	5,285,000
Totals	3,636,000	5,510,000	6,871,000	5,371,000	3,716,000	25,104,000

Actuals: Winter Storm Supply & Demand

CenterPoint Energy



Supply Portfolio
Winter Storm February 12 -22, 2021

CERC Managed Storage + AMA Storage	2,061,729	50%
FOM Call Options	1,077,885	26%
Daily Supply	1,007,210	24%
Total Supply	**4,146,824**	**100%**

Represents capacity on EGT which is 92% of our upstream pipeline supply in AR. The additional 8% represents small market pipeline volumes which are fulfilled by a combination of storage, baseload and daily gas.

Q & A

CenterPoint® Energy

APPENDIX

Buying Obligations

- Procure natural gas for essential **human needs** for space heating, cooking and water heating
- Provide supply to customers with **varying load conditions**
  - Extremely warm weather and severely cold weather
- **Supply products** that provide a balance for weather forecast errors and weekend varying loads such as:
  - Storage, call options, peaking (LNG/Propane)

Price Stabilization – Entire Winter

CenterPoint Energy

Storage and AMA gas stabilized the gas supply price

2020-21 Winter Season	Winter Actual		Winter Plan	
	Dth	%	Dth	%
CERC Managed Storage	2,581,282	10%	2,798,651	11%
Hedge Priced Gas (AMA)	15,891,726	59%	15,891,726	64%
Indexed Priced Gas	8,495,859	31%	6,099,623	25%
Total Winter Supply	26,968,867	100%	24,790,000	100%
Percent Stabilized		69%		75%

Product Types

CenterPoint Energy

Spot - Daily Market – supply purchased in the daily market, price at gas daily – not pre-arranged supply

Swing - Call Options – pre-arranged supply purchased prior to the winter months, priced at gas daily plus a premium. Daily call rights to the supply

Storage – purchased (injected) in the summer months and withdrawal in the winter at a fixed summer price

Baseload – purchased monthly or seasonally, flows everyday of the year/season – priced at Inside FERC first of the month index

Market Pricing – ICE
SLIDE IS NON-PUBLIC

CenterPoint Energy

Live Only

Product	Hub	Strip	Begin ...	End Date	RFQ	+/-	Sell	B Qty	Bid	Offer	O Qty	Buy	Last	Cha...	Settlement
NG Firm Phys, FP	ANR-SW	Next Day Gas	11May18	11May18		-		1800	2.0000	2.0350	10000		2.0000	0.02...	1.9730
NG Firm Phys, FP	CIG-Mainline	Next Day Gas	11May18	11May18		-		5000	1.6000				1.7200	1.72...	
NG Firm Phys, FP	CIG-Mainline South	Next Day Gas	11May18	11May18		-		5000	1.6000				1.6300	1.63...	
NG Firm Phys, FP	EGT-North	Next Day Gas	11May18	11May18				8500	2.5500	2.6200	10000				
NG Firm Phys, FP	EGT-South	Next Day Gas	11May18	11May18				2500	2.5900	2.7000	10000				
NG Firm Phys, FP	GTN-Malin	Next Day Gas	11May18	11May18		-		1000	1.7600	1.7900	5000		1.7900	-0.04...	1.8300
NG Firm Phys, FP	Golden Triangle	Next Day Gas	11May18	11May18				10000	2.6000						
NG Firm Phys, FP	HSC-HPL Pool	Same Day	10May18	10May18									2.6000	2.60...	
NG Firm Phys, FP	HSC-HPL Pool	Next Day Gas	11May18	11May18		-		10000	2.6000	2.7500	10000		2.7250	-0.01...	2.7370
NG Firm Phys, FP	Henry	Next Day Gas	11May18	11May18		-		5000	2.7250	2.8400	10000		2.7300	0.01...	2.7200
NG Firm Phys, FP	Iroquois (into)	Next Day Gas	11May18	11May18		-		5000	2.3500	2.5000	2200				2.5660
NG Firm Phys, FP	Katy-Oasis	Same Day	10May18	10May18						2.8000	10000				
NG Firm Phys, FP	Katy-Oasis	Next Day Gas	11May18	11May18		-		5000	2.7000	2.7500	8300		2.7250	0.05...	2.6730
NG Firm Phys, FP	NGPL-AM Pool	Next Day Gas	11May18	11May18		-		5000	2.1000	2.3000	5000		2.1950	2.19...	
NG Firm Phys, FP	NGPL-Midcont Pool	Next Day Gas	11May18	11May18		-		5000	1.8500	2.0650	10000		2.0300	0.04...	1.9830
NG Firm Phys, FP	NGPL-Nicor	Next Day Gas	11May18	11May18		+		5000	2.4200	2.4500	20000		2.4200	0.02...	2.4000
NG Firm Phys, FP	NGPL-Nipsco	Next Day Gas	11May18	11May18		+		10000	2.4250	2.5000	10000		2.4200	2.42...	
NG Firm Phys, FP	NGPL-TXOK East	Next Day Gas	11May18	11May18		+		3900	2.5500	2.5700	4000		2.5400	0.00...	2.5330
NG Firm Phys, FP	NNG-Demarc	Next Day Gas	11May18	11May18		+		3800	2.3300	2.3550	5000		2.3300	0.13...	2.2000
NG Firm Phys, FP	NNG-Ventura	Next Day Gas	11May18	11May18		+				2.3500	7000		2.3500	0.09...	2.2600
NG Firm Phys, FP	NWP-Wyoming	Next Day Gas	11May18	11May18		+		5000	1.8475	1.6900	2800		1.6900	1.69...	
NG Firm Phys, FP	Opal	Next Day Gas	11May18	11May18		+		10000	1.7100	1.7900	5000		1.7200	-0.05...	1.7700
NG Firm Phys, FP	PG&E-Citygate	Next Day Gas	11May18	11May18		+		2500	2.7450	2.7700	1600		2.7600	-0.05...	2.8180
NG Firm Phys, FP	Panhandle	Next Day Gas	11May18	11May18		+		13400	2.0000	2.0200	3700		2.0100	0.12...	1.8900
NG Firm Phys, FP	Socal-Citygate	Next Day Gas	11May18	11May18		+		1500	2.8000	3.0000	2500				3.2400
NG Firm Phys, FP	TGP-Z4 Marcellus	Next Day Gas	11May18	11May18		+		5000	1.5200	1.6300	1500		1.5000	1.50...	
NG Firm Phys, FP	TGP-Z5 200L	Next Day Gas	11May18	11May18		+		5000	2.1500	2.2000	5000		2.1800	2.18...	
NG Firm Phys, FP	TGP-Z6 200L	Next Day Gas	11May18	11May18		+		5000	2.1500	2.3500	10000				
NG Firm Phys, FP	EGT-Flex	Next Day Gas	11May18	11May18		+		8500	2.5500	2.6200	10000		2.5750	0.06...	2.5130
NG Firm Phys, FP	EGT-Flex	Same Day	10May18	10May18				1100	2.5000						
NG Firm Phys, FP	AGT-CG (non-G)	Next Day Gas	11May18	11May18		+		5000	2.1000	2.3500	5000		2.2650	2.26...	
NG Firm Phys, FP	CG-Mainline	Same Day	10May18	10May18		+		800	2.6000	2.6500	10000		2.6000	2.60...	
NG Firm Phys, FP	CG-Mainline	Next Day Gas	11May18	11May18		+		10000	2.5750	2.5900	1600		2.5900	0.02...	2.5680
NG Firm Phys, FP	Transco-85	Next Day Gas	11May18	11May18		-		1100	2.7200	2.7300	5000		2.7250	0.01...	2.7130
NG Firm Phys, FP	Socal-CG Imbalance	T - 1	9May18	9May18		-		5000	3.1100	3.1700	2500		3.1800	3.18...	
NG Firm Phys, FP	TGP-Manwah	Next Day Gas	11May18	11May18						2.1500	5000				
NG Firm Phys, FP	TGT-Mainline	Next Day Gas	11May18	11May18		+		10000	2.5700	2.5800	8900		2.5800	-0.02...	2.6030

ENERGY RESOURCES PLANNING TASK FORCE

PUBLIC HEARING AGENDA

WEDNESDAY, JUNE 2, 2021

10:00 a.m. – 4:15 p.m.

10:00 a.m. – 11:30 a.m.	**Call Meeting to Order**
	
	Public Hearing Guidelines:
	• Task Force Chair will moderate
	• Testimony will be limited to five minutes
	• Q&A will be limited to fifteen minutes
	
	Order of Testimony:
	1. CHS (ZOOM)
	    • Mark Porth, Senior Account Manager
	2. Ozark Petroleum
	    • Scott Sefton, Transport Driver/Dispatch

11:30 a.m.	**Recess for Lunch** Lunch will be provided for Task Force members

1:00 p.m. – 2:30 p.m.	**Call Meeting to Order**
	
	Public Hearing Guidelines:
	• Task Force Chair will moderate
	• Testimony will be limited to five minutes
	• Q&A will be limited to fifteen minutes
	
	Order of Testimony:
	1. Craft Propane
	    • Ron Craft, President
	2. NGL Energy Partners LP
	    • Aaron Reese, Senior Vice President of Liquids
	3. Arkansas Propane Gas Association (ZOOM)
	    • Hardy Thompson, Owner of Island Energy

2:45 p.m. – 4:15 p.m.	**Call Meeting to Order** **Public Hearing Guidelines:** • Task Force Chair will moderate • Testimony will be limited to five minutes

- Q&A will be limited to fifteen minutes

Order of Testimony:

1. Enable Midstream (ZOOM)
    - Steven Tramonte, Vice President of Transportation Storage
2. Summit Utilities (ZOOM)
    - Lizzie Reinholt, Vice President of Sustainability Corporate Affairs
    - Walt McCarter, Manager of Gas Supply and Contracts

ENERGY RESOURCES PLANNING TASK FORCE

MINUTES

DETAILS

Date and Time: 6/2/21 — Session 1: 10 – 11:30, Session 2: 1 – 2:30, Session 3: 3 – 4:30

Location: Department of Energy and Environment (E&E) Headquarters for Session 1 and Liquefied Petroleum Gas Board for Sessions 1 and 2, Live streamed on Arkansas PBS

Subject: Public Hearing

Task Force

Becky Keogh, E&E Secretary, Task Force Chair

Kevin Pfalser, Liquefied Petroleum Gas Board Director, Task Force Member

Lawrence Bengal, Oil and Gas Commission Director, Task Force Member

Mike Preston, Secretary of Commerce (Morning Session)

Steve Sparks, Director, Arkansas Economic Development Commission, Existing Business Resources, representing Mike Preston, Commerce Secretary (Afternoon Sessions)

Other Attendees

Scott Sefton, Ozark Mountain Petroleum, Inc.

Ronald Craft, President, Craft Propane, Inc.

Aaron Reece, Senior Vice President of NGL Energy Partners, LP

Laneigh Pfalser, Director, Arkansas Propane Gas Association

Hardy Thompson, Island Energy, Inc.

Steven Tramonte, Vice President, Commercial Transportation and Storage, Enable Midstream Partners, LP

Elizabeth Reinholt, Vice President, Sustainability and Corporate Affairs, Summit Utilities, Inc.

Fred Kirkwood, Chief Customer Officer, Summit Utilities, Inc.

Walt McCarter, Manager, Arkansas Oklahoma Gas Corporation

Mark Porth, Account Manager, CHS Inc.

Shane Khoury, E&E

Donnally Davis, E&E

Andrea Hopkins, E&E

Daniel Pilkington, E&E

Troy Deal, E&E

Tricia Treece, E&E **Beth Thompson,** E&E

AGENDA ITEMS

1. Call to Order **Secretary Keogh**

Secretary Keogh, as Task Force Chair, called the meeting to order at 10:24 am. The hearing was delayed due to a power outage at E&E Headquarters. Secretary Keogh explained hearing logistics. For each organization, opening testimony was limited to five minutes with up to fifteen minutes for questions and answers from Task Force Members. Opening logistics were repeated at the start of each session.

2. Summary of Testimony from Scott Sefton, Truck Driver **Ozark Mountain Petroleum, Inc.**

Mr. Sefton explained that he is a driver and dispatcher with Ozark Mountain Petroleum (Ozark Petroleum), which transports propane.

Mr. Sefton was asked whether Ozark Petroleum had any problems with supply outside of an event like the February 2021 winter weather event. Mr. Sefton explained that supply usually gets tight during the winter. For example, pipeline issues and loss of a terminal in North Little Rock constrained propane supply last year. During the February 2021 winter weather event, there were also some issues with propane supply from the refinery in Memphis due to the extreme cold temperatures.

Mr. Sefton was asked what the terminal being taken offline and other issues with the pipeline meant to Ozark Petroleum during the February 2021 winter weather event. Mr. Sefton explained that Ozark Petroleum drivers had to travel further distances to terminals, sometimes over 300 miles per trip. Traveling those distances limits the number of truck loads that can be delivered in a day.

Mr. Sefton was asked if Ozark Petroleum's situation was unique. Mr. Sefton responded that the supply issue is happening to everyone in the state.

Mr. Sefton was asked what his recommendations would be considering the hours of service requirements that were lifted on February 10th. Mr. Sefton recommended lifting the hours of service requirements sooner.

Mr. Sefton was asked how many bobtails a truck can fill. Mr. Sefton indicated that a truck load could fill about 4 bobtails.

Mr. Sefton was asked what else could be done to mitigate the propane supply situation. Mr. Sefton suggested that having more retail storage and more retail storage strategically located in the west, east, and central parts of the state would mitigate the propane supply situation.

Mr. Sefton was asked how many hold points there are for propane in the state. Mr. Sefton responded that there were hold points at the Memphis refinery, west of Paragould, the West Memphis Terminal, the River Port, and at the Amerigas Transloader.

Mr. Sefton was asked if there was nothing on the western side of the state and if incentivizing a transloader on the west side of the state might help. Mr. Sefton affirmed that there was nothing on the western side of the state and incentivizing a transloader there would help.

Mr. Sefton was asked if an incentive for independent dealers to increase capacity would help. Mr. Sefton affirmed that it would.

Mr. Sefton was asked what he is seeing with storage. Mr. Sefton explained that he has seen storage leaving the state with a lot of nationals closing their locations. He is unsure why.

Mr. Sefton was asked whether they were able to get trucks out given the road conditions during the February 2021 winter weather event. Mr. Sefton stated that there were 7 days they couldn't move.

Mr. Sefton was asked about Ozark Petroleum's service territory. Mr. Sefton responded that they run everything south of Hope Arkansas up to Nashville Tennessee and into northern Mississippi.
Mr. Sefton was asked whether terminals have to be located along pipelines or rail. Mr. Sefton affirmed this. Mr. Sefton stated that some terminals are exclusively supplied by rail, others by pipelines. Mr. Sefton mentioned that they also load gas out of the refinery in Memphis.

Mr. Sefton was asked if terminals in the western part of the state would have to be supplied with propane by rail. Mr. Sefton confirmed this.

Mr. Sefton was asked where propane serving the western part of the state comes from. Mr. Sefton said it comes out of the Dakotas and Canada.

Mr. Sefton asked if there is a volume that a terminal would have to experience to make it economic. Mr. Sefton responded that it would have to move a certain volume to justify the terminal.

Mr. Sefton was asked if there would be enough propane customers in western Arkansas for a terminal, which was affirmed by Mr. Sefton.

Mr. Sefton was asked about whether there is additional storage needed for distribution or terminals. Mr. Sefton indicated that increasing retail storage would be beneficial. However, the amount of storage is up to the retailers themselves. There is no regulatory minimum or maximum.

Mr. Sefton was asked to describe how customers are using propane and how it fit into their life for work during the ice event. Mr. Sefton said propane is used for heat, cooking, and generators.

Mr. Sefton was asked how he would characterize his customers. Mr. Sefton said he had both rural and urban customers.

Mr. Sefton was asked how being short of propane before a storm event could be avoided in the future. Mr. Sefton responded that propane supply shortages were common and that it has gotten worse over the years.

Mr. Sefton was asked whether he would recommend engaging the national guard and others to assist earlier to make sure roads were passable. Mr. Sefton answered affirmatively.

Mr. Sefton was asked what other groups might be able to help assist in delivery of propane during a storm event. Mr. Sefton suggested the Highway Department and County Road Departments. Mr. Sefton mentioned that some of the trouble they had was getting in and out of the customer locations. The customers would have to clear those areas. There are some things that can be one to weatherize the trucks, but it's a lot of work and not really all that safe.

Mr. Sefton was asked about whether Ozark Petroleum has experienced a situation where they have allocation, but customers don't have product available to them. Mr. Sefton affirmed that this happened for some customers who were forced to get propane from out of state.

Mr. Sefton was asked who determines allocation. Mr. Sefton responded that it was the suppliers and owner of the terminals.

Mr. Sefton was asked whether the problem was a lack of capacity or product in the pipeline. Mr. Sefton responded that not enough propane was being produced.

Mr. Sefton was asked whether he was aware of any pricing adjustments on propane during the period. Mr. Sefton was not aware of any.

Recess **10:52 – 1:10**

3. Summary of Testimony from Ronald Craft **Craft Propane, Inc.**

Mr. Craft described changes happening in the propane industry over the years. He stated that supply has increasingly become a problem since 2014 when the Enterprise pipeline reversed a line that runs through the center of Arkansas. He said some of the dealers in NE Arkansas ran out of gas. Mr. Craft mentioned that there were two types of customers: keep fulls and will calls. For keep fulls, Craft Propane tops the tank on a regular route. For will calls, some customers wait to call until they are extremely low.

Mr. Craft said that through the years they always had supply. Craft Propane works to manage its supply and have pulled gas from as far away as Alabama and Mississippi. Mr. Craft stated that, if you miss a load, it is hard to catch up.

Mr. Craft discussed working to manage their customer base during the storm. They were aware of the potential for bad whether 4 weeks prior to arrival. Craft Propane continued running its keep full routes to ensure that those customers were taken care of so they could handle will calls when they came in. Mr. Craft stated that they kept running during the ice if it was safe to do so.

Mr. Craft suggested that extra retail storage would have been effective, but it may not be economic due to the current high prices of steel. Mr. Craft also suggested that having more terminals established in the state would reduce the need to run long distances once supply gets short. Mr. Craft also suggested lifting the hours of service requirements sooner. He explained that they were already in the middle of the emergency before hours of service requirements were lifted during the February 2021 weather event. Mr. Craft also suggested public service announcements urging people to call ahead.

Mr. Craft was asked where Craft Propane was located. Mr. Craft stated they were located in the Jonesboro area.

Mr. Craft was asked to characterize his customers and how they are using propane. Mr. Craft responded that propane is being used for hot water, generators, and heating for residential customers. Mr. Craft mentioned that industrial fork lifts use propane. Mr. Craft also mentioned that they have commercial, restaurant, and church customers.

Mr. Craft was asked how he thinks the state could be better prepared. Mr. Craft responded that without more terminals or pipelines, the only thing the state could do would be to lift hours of service requirements sooner.

Mr. Craft was asked if they completely ran out of propane. Mr. Craft responded that they did not.

Mr. Craft was asked if the main problem with the propane industry was distribution. Mr. Craft said that he has managed to stay in gas all these years, but got lower in supply than they would like to be.

Mr. Craft was asked where they would need additional terminal locations. Mr. Craft mentioned that the closest terminal is 40 miles and that there are a few others. Mr. Craft stated that the Memphis refinery went down due to the cold weather reducing available supply.

Mr. Craft was asked how the I-40 bridge repairs affects transportation. Mr. Craft responded that if the 40 bridge was down in winter, it would be devastating due to the additional hour and a half that would be required to travel.

Mr. Craft was asked if his customer base was growing, which he affirmed.

Mr. Craft was asked if the growth was industrial or residential to which Mr. Craft responded both.

Mr. Craft was asked if additional terminals were put in other parts of the state if there would be a sufficient customer base to justify it. Mr. Crafted said he thinks so.

Mr. Craft was asked what kind of investment additional storage would require. Mr. Craft responded that it would cost millions of dollars and that the high cost of steel would make it even more expensive now than it was two years ago.

Mr. Craft was asked if he sees any advice or regulation coming from the board to allocate propane at a dealer level if supply is short instead of completely filling tanks. Mr. Craft did not think that was feasible.

Mr. Craft was asked if there was a commercial use of propane, which he affirmed.

Mr. Craft was asked if propane could help when we have natural gas shortages. Mr. Craft stated that in the 1960's and 1970's there was a lot on standby at industrial plants, but many were sold off in the 1980's.

4. Summary of Testimony from Aaron Reece, Senior Vice President of NGL Energy Partners, LP	**NGL Energy Partners, LP**

Mr. Reece explained that NGL is a midstream supplier moving propane from producers to dealers. NGL operates a terminal in Little Rock and Dexter, MO. They formerly operated a terminal in North Little Rock, which was decommissioned last year because the pipeline was unsafe. NGL Energy Partners also markets propane from the Valero refinery in Memphis. They truck propane up to the terminals and also receive propane via pipeline or rail.

When the shale revolution occurred, the Techno pipeline became underutilized. Now it is a batch pipeline. Propane competes with other refined products in the pipelines. Sometimes they can't fill the terminals because they aren't receiving a batch. They have to nominate batches before the 15th of the month prior. On January 15th, they did not forecast the needs they would have during the February 2021 winter weather event. Mr. Reece also explained that shipping cycles for propane to Arkansas terminals are ten days long via pipeline. For rail, some product takes even longer. They have to forecast needs many days in advance. Mr. Reece indicated that Arkansas is a good market with supply available from many different directions. Mr. Reece mentioned that there are no pipelines in the western part of Arkansas and that rail became more competitive after the shale gas revolution.

Mr. Reece stated that sales in February 2021 were 25% higher than in 2020 and that hazardous roads also made transportation difficult. Furthermore, Mr. Reece conveyed that there was a delay in their February batch and a small explosion at the Valero Refinery cut off that source of supply during the storm.

Mr. Reece suggested that subsidies or low cost loans to incentivize retailers to put in more storage would be helpful. He pointed to Michigan as a state that is doing this. Mr. Reece also suggested that gross vehicle weight waivers could help by allowing bigger trucks to deliver propane.

Mr. Reece mentioned that Arkansas has a carrier shortage. It is difficult to recruit commercial drivers with hazardous materials training when they aren't paid more than they could get working for FedEx.

Mr. Reece was asked if he has any thoughts around how to prioritize propane for Arkansas on the pipeline. Mr. Reece responded that there was actually concern that Enterprise might delete propane from the tariff before the Magellan pipeline was built. Mr. Reece explained that, at the end of the day, a pipeline is about keeping thing moving and having a home for product. Mr. Reece indicated that if there is propane remaining after filling up all of the terminals through Dexter, MO, the remaining supply doesn't have a home. Mr. Reece suggested encouraging customers to lift propane during the summer so they could earn allocation of the pipeline.

Mr. Reece was asked about encouraging customers to pull earlier in the season. Mr. Reece responded that, to do this, there would need to be additional storage at the retail level.

Mr. Reece was asked what determines batch time and frequency. Mr. Reece responded that you need a minimum quantity, but that they need to make sure that they can hold the product at the terminal.

Mr. Reece was asked whether they have a carrier distribution system or driver problem. Mr. Reece responded that it is a little bit of both. He mentioned that with amazon and other shipping, there is a heavy need for drivers.

Mr. Reece was asked if NGL operates a natural gas pipeline. Mr. Reece responded that they did not.

Mr. Reece was asked if they were making a judgment call about volume of propane when they nominate space on the pipeline. Mr. Reece confirmed that they make this determination on or before the 15th of the month prior.

Mr. Reece was asked about the lead time that they have based on predicted weather evets. Mr. Reece said that making determinations far enough in advance for rail is difficult because rail terminals typically don't have as much storage. Mr. Reece said that even if they had tried to buy additional gas to react to the forecast, it would be too late given the lead times.

Mr. Reece was asked whether it is economically viable to build more terminals. Mr. Reece responded that storage can be very costly if they don't predict correctly. He mentioned that it would be difficult to locate a pipeline in western Arkansas because competing with the refinery in Oklahoma would make it cost-prohibitive.

Mr. Reece was asked what months that they build allocation on the pipeline. Mr. Reece mentioned that they used to lift in the summer to receive allocation in the winter. However, the Tepco pipeline is now 12-month rolling.

Mr. Reece was asked whether taking gas from Valero hurt their allocation on the pipeline for later. Mr. Reece affirmed that it could take away from the allocation.

Mr. Reece was asked about transloading operations. Mr. Reece answered that load times with a transloader takes a significant amount of time. He stated that you wouldn't have storage and that it is different from unloading a rail care into storage.

Mr. Reece was asked about the number of rail cars used in transloading operations. Mr. Reece responded that they can have 10 cars on and 10 off on a spur.

Mr. Reece was asked about the volume of one rail car. Mr. Reece responded that they can usually fill 3 transports with one rail car.

Mr. Reece was asked about who feeds the Carthage pipeline. Mr. Reece responded the Magellan pipeline and a 2000 barrel cavern leased by Magellan.

Mr. Reece was asked whether the Carthage pipeline went down because of the weather. Mr. Reece confirmed this.

Mr. Reece was asked if there were no pipelines in Texas and Oklahoma feeding into western Arkansas. Mr. Reece confirmed this.

Mr. Reece was asked whether he had any thoughts on additional pipelines. Mr. Reece responded that they could use some existing pipelines that are no longer in use if they have the correct pressure specification. He stated that they could repurpose a natural gas pipeline, but that those pipelines tend to not be recommissioned.

5. Summary of Testimony from Laneigh Pfalser, Director and Hardy Thompson, Island Energy, Inc.	**Arkansas Propane Gas Association/Island Energy, Inc.**

Ms. Pfalser spoke about the APGA members gratitude for lifting the hours of service requirements during the February 2021 winter weather event. She mentioned that the members of the association faced other issues and that Mr. Thompson was going to speak to his experiences.

Mr. Thompson of Island Energy discussed his businesses' use of monitors on tanks and serving exclusively "keep fill" customers. Mr. Thompson emphasized the need for relationships with propane suppliers to get service. Mr. Thompson mentioned that there was a week during the February 2021 winter event when they were only taking minimum amounts to their customers and weren't taking any new customers. Mr. Thompson explained how customers who own their tank shop can make it difficult for suppliers to supply them. The supplier can't rely on these customers for their allocation. Mr. Thompson discussed their reliance on storage during the February event, which was built based on historical needs. Mr. Thompson explained that this was just not a normal time and that they worked with other groups like NGL and other suppliers to get gas brought in when the Memphis refinery went down.

Mr. Thompson explained that the propane business is similar to utilities in that diversity is needed. Mr. Thompson talked about how sensors in tanks help his company manage demand.

Mr. Thompson was asked whether the tank monitors communicate in real time. Mr. Thompson responded that the sensors provide notifications to him about tank levels every morning or if the tank reaches a certain level.

The APGA representatives were asked about early seasonal notice to customers. Mr. Thompson responded that notice is going to vary from marketer to marketer. They use social media to communicate to their customers, but aren't sure what would help people who aren't their customers. Mr. Thompson mentioned that putting out a conserve gas notice might cause a panic.

Mr. Thompson was asked what percentage of the propane industry has tank monitors in place. Mr. Thompson responded that very few tanks have monitors. Mr. Thompson said they make sense for his business and that it's a good economic decision for higher use customers. Mr. Thompson mentioned that the propane business is very fragmented and it is hard to get a lot of people together around a new technology.

Mr. Thompson was asked whether the tank monitors use the customer's internet service or if his company pays for their network use. Mr. Thompson responded that they use dual band cellular and that the cost is minimal ($3/tank).

Mr. Thompson was asked about how long it has been since his company acquired the location in Osceola. Mr. Thompson responded that they acquired in it in March 2017 and that they have also opened a store in Pocahontas.

Mr. Thompson was asked whether they are purchasing new or used steel. Mr. Thompson responded that their first preference was to buy refurbished tanks out of Oklahoma, but that they will buy used or new tanks if they have to.

Mr. Thompson was asked about the impact of steel prices. Mr. Thompson responded that the cost of used tanks have gone up by 60%.

Mr. Thompson was asked whether the hours of service waiver was beneficial. Mr. Thompson responded that it was. He explained that once you get behind you are always behind. Mr. Thompson suggested lifting hours of service requirements every winter instead of the waiver being triggered by an event.

Mr. Thompson was asked what months he does most of his business. Mr. Thompson mentioned that most of their business is in January, February, March, and December. They use the off months to set tanks. They also do significant fork lift service year round.

Mr. Thompson was asked what a periodic hours of service waiver would look like. Mr. Thompson responded that they can't predict the weather soon enough to make a decision. By the time the Executive Order was issued, it was already late and there are only so many trucking companies. Mr. Thompson mentioned that he would like to see propane delivered by rail in Northwest Arkansas, but that he isn't sure it would be economical.

Ms. Pfalser explained that propane can also be used in manufacturing and for powering school buses.

Recess	**2:34 – 2:50**
6. Summary of Testimony from Steven Tramonte, Vice President, Commercial Transportation and Storage	**Enable Midstream Partners, LP**

Mr. Tramonte explained that Enable operates two interstate natural gas pipelines –EGT and MRT. These pipeline are subject to FERC rules. Enable is exclusively a transportation provider. Mr. Tramonte described Enable's preparation for the weather event, including keeping personnel on site at compressor stations and storage sites and testing back up generation to ensure that an interruption in power wouldn't impair equipment. Mr. Tramonte stated that they lost almost 50% of their supply due to well and pipeline freezes while demand increased by 45% over the course of the February 2021 winter weather event. Mr. Tramonte described imbalances reducing their ability to meet system pressure requirements. As the system deteriorated, they prioritized loads for human needs customers above all other customers regardless of level and type of service. Storage and customers cutting back on their usage helped the system. Mr. Tramonte stated that Enable is also exploring additional sources of supply.

Mr. Tramonte was asked if he could speak to what Enable learned about customer notifications during the event and whether customers could be better educated to have the right agreement in place. Mr. Tramonte explained that Enable had seen events with similar temperatures, but never for the duration experienced in February 2021. Mr. Tramonte stated that the extreme temperatures and duration caused Enable to have to enact prioritization of human needs in a way they hadn't done before. Mr. Tramonte stated that customers have to submit an affidavit saying that they do serve human needs and how much they need for that. They are learning about utility and industrial customer needs to avoid catastrophic damage to equipment and how to go through the process to get those affidavits done.

Mr. Tramonte was asked whether their compressor stations experienced a power loss and if they have back-up power systems. Mr. Tramonte responded that a number of compressor stations do have back-up power and that they did not experience power interruptions at their compressor stations. Mr. Tramonte emphasized that the problem was that more gas was being taken off the system than coming on, causing pressure drops on the pipeline.

Mr. Tramonte was asked about lessons learned. Mr. Tramonte responded that most of the supply in Oklahoma and Northern Arkansas saw the largest impacts from the wellhead freeze off. Mr. Tramonte explained that increased supply ability in northern Arkansas would have provided access to more supply and storage assets located in northern Louisiana.

Mr. Tramonte was asked about the best way to communicate about the affidavit process. Mr. Tramonte responded that being more proactive is pivotal so that customers understand priority each winter and they don't wait until an event to get affidavits.

Mr. Tramonte was asked whether Enable's pipeline runs east to west along the Arkansas River. Mr. Tramonte responded that it runs primarily east to west then south to Louisiana.

Mr. Tramonte was asked whether the Arkoma basin supplies gas in their pipeline. Mr. Tramonte responded that it contributes, but is not the majority of supply.

Mr. Tramonte was asked how much of the gas that is brought into the system stays in Arkansas. Mr. Tramonte responded that he would have to follow-up with this information.

Mr. Tramonte was asked whether a large portion of the Fayetteville Shale gas goes east. Mr.Tramonte stated that competing pipelines move a majority of that volume further east.

Mr. Tramonte was asked where storage of natural gas happens. Mr. Tramonte responded that it occurs in Louisiana and Oklahoma. Mr. Tramonte discussed the use of geological reservoirs and salt caverns as storage facilities.

7. **Summary of Testimony from Elizabeth Reinholt, Vice President, Sustainability and Corporate Affairs, Summit Utilities, Inc., Fred Kirkwood, Chief Customer Officer, Summit Utilities, Inc., Walt McCarter, Manager, Arkansas Oklahoma Gas**

Arkansas Oklahoma Gas Corporation/ Summit Utilities, Inc.

Mr. McCarter described the Arkansas Oklahoma Gas Corporation (AOG) owned by Summit Utilities as a gas distribution company that operates in western Arkansas. Mr. McCarter explained that AOG always takes weather into consideration for natural gas procurement. They use historic events and market response to model needs.

Mr. McCarter explained that the AOG supply strategy includes a diverse portfolio with firm service contracts. Mr. McCarter described the extreme index prices and shortages due to the February 2021 winter weather event. AOG curtailed interruptible and industrial customers to ensure they could serve residential customers. They issued communications to conserve.

The Summit Utilities representatives were asked whether they had any lessons learned that they can put in the Task Force's recommendations that could apply to all natural gas providers in the state and to commercial organizations to better prepare for potential curtailments. Mr. Kirkwood explained that this was a unique experience for both them and the customers. He suggested updating customer profiles to ensure that they have the appropriate direct contacts. Mr. Kirkwood explained that they called large industrial customers, but couldn't call all of their smaller commercial customers. They did not physically shut the smaller commercial customers off, but they did tell them they were being curtailed and to turn down thermostats. Mr. Kirkwood explained that they didn't have much notice of the supply shortages. He stated that they nominated the appropriate amount of gas but weren't notified in advance that they couldn't get all of the supply they nominated. They set up a text messaging program to help with communications about conserving and overall curtailment. They also kept customer service representatives on for longer hours to answer customer questions.

The Summit Utilities representatives were asked whether they had any issues with weatherization. The representatives responded that the AOG system functioned well during the cold weather, but that they had lower pressures at some of the dead end feeds due to the supply shortage.

The Summit Utilities representatives were asked whether they had to purchase any higher cost gas to augment the system. The representative responded that AOG contracts all of their gas in an annual process. They always try to nominate gas in order of economic priority. They did have to call on higher priced gas, but didn't have to go outside contracts onto the spot market.

The Summit Utilities representatives were asked about how the costs of the higher gas were allocated to customers. The representatives responded that they were primarily allocated to residential and small commercial companies. They stated that larger customers typically buy on third-party contracts so they are not attributing the high price gas demand to those customers.

The Summit Utilities representatives were asked where their customer base is located. They responded that their customers are located in five counties in western Arkansas in the Fort Smith/Van Buren area.

The Summit Utilities representatives were asked who would communicate to them that the natural gas supply is dropping. The Summit Utilities representatives responded that there are three parties in the relationship: Distributors, suppliers, and pipeline operators. They put supply nominations into the pipeline for delivery to the system. When the gas didn't produce, they got notifications from the pipeline about it. Then, they had to call suppliers regarding what they could do to get more gas.

The Summit Utilities representatives were asked whether there was a process to notify customers of cost increases so they could choose to voluntarily reduce. The representatives responded that it's possible. For large industrials, they buy through a third party and AOG is just a distributor. The industrials would need to work with their marketers on issues of cost.

8. Summary of Testimony From Mark Porth, Account Manager **CHS Inc.**

Mr. Porth described CHS as a wholesaler of propane covering coast-to-coast. He works in the Missouri, Arkansas, Kansas, Texas, and New Mexico region. Mr. Porth explained that most of the fuel in Arkansas comes from out of state. In the summer, there is enough local infrastructure to support demand. When it cools off, they are more heavily reliant on transportation carriers bringing fuel into Arkansas. Mr. Porth stated that none of their customers had an outage because they had a plan prepared for winter.

Mr. Porth was asked about where in Arkansas is his core business. Mr. Porth responded that CHS serves primarily the northern half of the state and that fuel can come in from Oklahoma, Kansas, Missouri, and Illinois.

Mr. Porth was asked who his customers are. Mr. Porth responded that they provide to the retailers who then deliver to residential or industrial customers. CHS is wholesale only.

Mr. Porth was asked whether a shortage of carriers affects his business. Mr. Porth explained that a majority of propane in the winter comes from outside Arkansas and that carriers are a huge part of what they do. Mr. Porth stated that hours of service requirements limit what a carrier can run. In the summer, they have adequate carriers. But when they go long distances, it can cut their trucking fleets ability to deliver fuel. Mr. Porth recommended that being progressive on hours of service requirements before they get behind would be a great benefit to his customers, especially when the carriers must travel long distances to get propane. Mr. Porth stated that the propane industry has a distribution issue, rather than a supply issue. Mr. Porth explained that there is a shortage of drivers with the required commercial driver's license and hazardous materials training.

Mr. Porth was asked about retention of existing propane drivers. Mr. Porth responded that the drivers are paid well and are very valuable employees. Mr. Porth indicated that a carrier may be better able to speak to driver retention.

Mr. Porth was asked if CHS operates a terminal or something different. Mr. Porth responded that they bring propane into Arkansas through 10 different locations working through a terminal.

Mr. Porth was asked how CHS operates. Mr. Porth responded that they prepare the supply and the transport carrier then delivers the propane to the customer.

Mr. Porth was asked whether CHS has storage. Mr. Porth responded that they have a storage facility and other supply sources.

Mr. Porth was asked whether wholesale services are transferrable to western Arkansas, which currently lacks a terminal or whole sale point. Mr. Porth explained that you could do that through many different ways. For instance, you can invest in a rail car facility. But, rail car facilities are typically not economic in the propane industry 8 or 9 months out of the year. Mr. Porth said that other locations must also move fuel. For every load they make in the summer, they make one in the winter. But demand in the winter is three times that in summer. Retailers in western Arkansas have to go to Conway, Kansas for their gas. The time required to get gas from their and the time a truck sits and waits in line both count against a driver's hours of service.

Mr. Porth was asked how CHS could strengthen its position in the state and whether a transloading operating would be feasible. Mr. Porth responded that they are looking at multiple locations to see what might work. Mr. Porth described the cost premium that North Dakota and Calgary put on winter propane rail cars. This cost makes it more economic to send trucks to their suppliers.

Mr. Porth was asked whether having access to a spur for a 90-day window would be beneficial. Mr. Porth responded that they already have a couple of these in place, but the cost premium makes it difficult. Having the asset sitting for months is not economic. Mr. Porth also discussed export facilities on the west coast and in Pennsylvania diverting fuel that would otherwise go south to the states.

Mr. Porth was asked whether they had difficulty finding transportation the first couple of weeks in February. Mr. Porth responded that they didn't. Mr. Porth commented that CHS works closely with carriers. He explained that carriers have some slack and can haul other things in the off season. Mr. Porth suggested that helping with hours of service would make things easier and that drivers have an incredible track record for safety.

9. Closing Remarks **Secretary Keogh**

Secretary Keogh concluded the hearing at 4:00 pm.

ENERGY RESOURCES PLANNING TASK FORCE

ORIGINAL

PUBLIC HEARING

JUNE 2, 2021

BEFORE:

BECKY KEOGH, CHAIRMAN AND SECRETARY OF THE ARKANSAS DEPARTMENT OF ENERGY AND ENVIRONMENTAL QUALITY

MICHAEL PRESTON, SECRETARY OF COMMERCE AND EXECUTIVE DIRECTOR OF THE AEDC

LARRY BENGAL, DIRECTOR OF THE ARKANSAS OIL AND GAS COMMISSION

KEVIN PFALSER, DIRECTOR OF THE ARKANSAS LIQUIFIED PETROLEUM AND GAS BOARD

STEVEN SPARKS, DIRECTOR OF THE AEDC, EXISTING BUSINESS RESOURCES DIVISION

TAKEN BEFORE Karisa J. Ekenseair, Certified Court Reporter, LS Certificate No. 802, Bushman Court Reporting, 620 West Third Street, Suite 302, Little Rock, Arkansas 72201 on June 1, 2021 at the Arkansas Department of Energy & Environmental Quality, 5301 Northshore Drive, North Little Rock, Arkansas commencing at 10:24 a.m.

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SECRETARY KEOGH: Good morning. Today is June 2nd, 2021. And appreciate your patience as we've encountered a few technical issues this morning, including a power outage at our location here at the Arkansas Department of Energy and Environment Headquarters.

I'm advised by Entergy that they're working diligently to restore power to this area of the city and we hope that we have that resumed later today. But in the meantime, we are using other technology to try to broadcast this. If you have difficulty hearing, we apologize. We are recording this and you should have access to this recording in the future, should you desire to hear any testimony that you're unable to hear during this live stream itself.

We are here today to hear testimony from in person as well as through Zoom technology for the Energy Resources Planning Task Force. I am Becky Keogh. I'm Secretary of the Arkansas Department of Energy and Environment. And I have the pleasure of serving on this Task Force with also Secretary of Commence, Mike Preston who sits to my right this morning; Director of the Oil and Gas Commission, Larry Bengal who is to my left; and to my far right, Kevin Pfalser, Director of the Liquified Petroleum

Gas Board. And we appreciate all of those participants and members participating this morning.

We also have a couple of people present in the room and audience. I have a number of staff supporting this, and I appreciate their work. But due to time, I'm going to move forward at this point and just move forward into the actual testimony that's scheduled for this morning.

Before I do so, I wanted to, as a matter of introduction, just mention that on March 3rd, 2021, Governor Asa Hutchinson signed Executive Order 21-05 which established the Energy Resources Executive Planning Task Force. This Task Force was set up with the intention of conducting hearings and collecting information that would be beneficial to the state to do after-action assessments of the ice storms that we encountered in February, as well as created lessons learned for follow-up, should we encounter other events.

So as we gather this information, we want to better prepare ourselves and our state's energy infrastructure in the event of another statewide emergency.

As Chair of the Task Force, I will call forward the speakers this morning that will provide testimony. And when I do call your name, we -- your organization, if you would come forward, and due to the technology, stand adjacent to the computer that we're using for Zoom this morning. We will be able to hear and record your testimony in better shape.

With that, when you come forward, if you would, state your name, title, and organization for the record. We have allowed -- allotted five minutes for an opening statement. We know that the organizations that are appearing have submitted prefiled testimony.

And so we will be asking for an opening statement. And then following that opening statement, we will open -- or I will open the Task Force members -- the floor to the Task Force members who will ask questions of the representatives here before us. We've allotted about 15 minutes for that process. And I know that we have Andrea Hopkins sitting in front right here who will be gently reminding people of the time, and we ask that everyone be respectful of the time limits.

This morning we will -- our first speaker will be Ozark Petroleum, and I'll ask you to come forward, the representative from Ozark Petroleum this morning, and begin the testimony as scheduled.

Thank you for being present.

SCOTT SEFTON: Welcome.

SECRETARY KEOGH: We appreciate your participation and involvement.

SCOTT SEFTON: I'm Scott Sefton with Ozark Mountain Petroleum. I'm a driver/dispatcher. We've been in business about eight years transporting propane. Actually, they have been -- Ozark Mountain Petroleum has been in business transporting gas and diesel for over 30 years and we've just started the propane eight years ago. We currently run ten transports.

SECRETARY KEOGH: Do you have any additional comments?

SCOTT SEFTON: No.

SECRETARY KEOGH: Okay. Thank you. It's helpful to know your operations here in the state. I think that informs us of your presence here and we appreciate Ozark being part of the Arkansas system for liquified petroleum.

I'll begin and turn first to Director Pfalser for questions. And then we'll kind of come down the row here if there's follow-up questions by any of the other Task Force members.

SCOTT SEFTON: Okay.

SECRETARY KEOGH: So I'll turn to Director Pfalser to begin our questions this morning.

DIRECTOR PFALSER: Scott, we appreciate you taking the time --

SCOTT SEFTON: Yes, sir.

DIRECTOR PFALSER: -- to be with us. And you know, the events back in February that prompted this Task Force being put together, you're well aware of what kind of hardship that had on our industry.

SCOTT SEFTON: Oh, yeah.

DIRECTOR PFALSER: The oil and gas industry.

SCOTT SEFTON: Yep.

DIRECTOR PFALSER: But in a broader sense, let me ask you this: Outside of an event like that, do you foresee or have you in the past had any problems with supply outside of an event like this on a year-to-year basis?

SCOTT SEFTON: Oh, yeah. Usually through the winter, obviously, yeah. Supply does get tight. You know, different reasons that I have heard, you know, pipeline issues. And you know, we lost this -- this last winter they, for whatever reason, they closed the -- we lost a terminal.

DIRECTOR PFALSER: Rixie.

SCOTT SEFTON: Here in North Little Rock. Yes.

DIRECTOR PFALSER: Okay.

SCOTT SEFTON: That was about a 1.2 million gallon facility. Reasons unknown to me why they closed it, you know. And then during the crisis we had back during mid-February, there was some refinery issues, you know, due to the extreme cold temperatures.

DIRECTOR PFALSER: So when --

SCOTT SEFTON: And that was -- go ahead.

DIRECTOR PFALSER: So when that happened, when that weather came in and we had one of the terminals that had been servicing -- serving the area --

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: -- taken offline --

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: -- I think that even a refinery in Ponca City went down?

SCOTT SEFTON: Yes. Yes.

DIRECTOR PFALSER: Some of the terminals that were fed off the pipeline because of the same issues --

SCOTT SEFTON: Yep.

DIRECTOR PFALSER: -- that we heard in testimony from natural gas --

SCOTT SEFTON: Yep.

DIRECTOR PFALSER: -- they could not get propane to the terminal. So what did that mean as a transporter for you?

SCOTT SEFTON: Well, we had to travel out of state. As far as we're concerned: Hattiesburg, Mississippi; Moberly, Missouri; Jefferson, Missouri; and East St. Louis was the terminals that we had to go to, which you're talking 300-plus miles either direction, you know, to come back into the state.

And when you're traveling those distances with the hours of service that we have to abide by, you're looking at basically one load a day per truck. And in our case, like I said before, we have ten trucks. And you're taking if -- if we could load, like, out of the Rixie terminal, for example --

DIRECTOR PFALSER: Right.

SCOTT SEFTON: -- you know, one of my trucks could run three loads a day, you know, versus if you're having to go to Hattiesburg, Mississippi, for example, travel 300-plus miles down there, you have to travel the same 300-plus miles back, obviously. And you're looking at one load a day.

DIRECTOR PFALSER: Okay. And so -- and you're not in a unique situation. If this is happening with Ozark Petroleum, when you're -- it's happening to everybody in the state?

SCOTT SEFTON: Yes. Everybody. Everybody. Absolutely.

DIRECTOR PFALSER: So at the first of February, I believe that the governor helped the industry out with an hours of service on the 10th of February. And that was just a few days prior to -- less than a week prior to the main event --

SCOTT SEFTON: Right. Exactly.

DIRECTOR PFALSER: -- happening.

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: And so what -- what would be your recommendation concerning hours of service? I mean, that was a big help.

SCOTT SEFTON: Oh, yes. Tremendous.

DIRECTOR PFALSER: That allowed you all to run longer.

THE WITNESS: Yes.

DIRECTOR PFALSER: It allowed the bobtails and the independent dealers to run longer.

SCOTT SEFTON: Right.

DIRECTOR PFALSER: Once the propane did get back.

SCOTT SEFTON: Yeah.

DIRECTOR PFALSER: So what would be your suggestion concerning hours of service?

SCOTT SEFTON: I would say lifting them sooner.

DIRECTOR PFALSER: Okay.

SCOTT SEFTON: You know, referring to this -- this last winter, that would have helped us. If we could have had another couple of weeks of running -- you know, and you -- we run on hours of service for a reason, you know. I mean, you can't run around the clock obviously. But if we had a little more leniency -- and like I said, if they would have done it sooner, I think that would have helped.

DIRECTOR PFALSER: And then -- and kind of talk about, if a dealer has -- they have X number of gallons of storage --

SCOTT SEFTON: Exactly.

DIRECTOR PFALSER: -- at their disposal --

SCOTT SEFTON: Yeah.

DIRECTOR PFALSER: -- and if that storage is on the bottom side --

SCOTT SEFTON: Right.

DIRECTOR PFALSER: -- and you -- we run into this situation and they have three bobtails, four bobtails pulling out of one storage --

SCOTT SEFTON: Right.

DIRECTOR PFALSER: -- how many bobtails can you fill off of one transport load?

SCOTT SEFTON: About four. We normally carry about 9,000 gallons.

DIRECTOR PFALSER: Okay.

SCOTT SEFTON: And your average bobtail is about 2600, which --

DIRECTOR PFALSER: Something --

SCOTT SEFTON: Yeah. You know --

DIRECTOR PFALSER: Between 3 and 4?

SCOTT SEFTON: That's the average. 23 to 26, you know.

DIRECTOR PFALSER: Okay. So when we see a weather event occurring, maybe ask the governor to consider that sooner --

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: -- would be a benefit?

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: Okay. Outside of -- outside of that, what else could you see could be a benefit to help mitigate the situation?

SCOTT SEFTON: Well, I would say going back to what you said about the retailer storage, you know, they -- some of them need more storage, you know. And I think some more terminals, whether it's rail terminals, could be placed in the state strategically, maybe on the west side of the state, the east side of the state, maybe in the central part of the state, you know.

DIRECTOR PFALSER: Currently with Rixie being taken out of the system, how many pulling points do we have in the state?

SCOTT SEFTON: Currently we have the Memphis refinery, which supplies a lot of the eastern part of the state. Then you have the terminal at Light, which is up just west of Paragould. And then we have the West Memphis terminal.

DIRECTOR PFALSER: And what about, have you ever pulled any product out of the river port?

SCOTT SEFTON: Yes. I forgot about that. Yes. The port over here. NGL has the port terminal. Yeah. And it's a rail facility.

DIRECTOR PFALSER: It's a rail facility?

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: Are there any others that you have pulled from in the state?

SCOTT SEFTON: None within the state. No.
DIRECTOR PFALSER: Doesn't the --
SCOTT SEFTON: Well, AmeriGas has the one up here off of Broadway.
DIRECTOR PFALSER: The transloader?
SCOTT SEFTON: The transloader. Yes.
DIRECTOR PFALSER: That they have in North Little Rock?
SCOTT SEFTON: Yes. Yep.
DIRECTOR PFALSER: Have you ever loaded there before?
SCOTT SEFTON: Oh, yeah. Yes. But as far as I know, the last year they did sell some gas to other customers, but it's primarily for their --
DIRECTOR PFALSER: Their own use?
SCOTT SEFTON: Yes. Their own use. Yes. Yes.
DIRECTOR PFALSER: Okay. And Light, the -- that's the Valero refinery you're referring to?
SCOTT SEFTON: No. The Valero is in Memphis.
DIRECTOR PFALSER: In Memphis?
SCOTT SEFTON: Memphis refinery.
DIRECTOR PFALSER: And NGL is West Memphis?
SCOTT SEFTON: Yes. West Memphis and Light

and the port, as you referred to, over here off of 440.

DIRECTOR PFALSER: So there's almost nothing on the western side of the state?

SCOTT SEFTON: No, sir.

DIRECTOR PFALSER: So --

SCOTT SEFTON: No.

DIRECTOR PFALSER: So possibly incentivizing in some way to put in some -- maybe a transloader --

SCOTT SEFTON: Yes. Yes. Yeah.

DIRECTOR PFALSER: -- would be the most economic way to offset, to help out?

SCOTT SEFTON: Uh-huh.

DIRECTOR PFALSER: And storage, possibly looking at some kind of incentive for the independent dealer --

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: -- to --

SCOTT SEFTON: Increase their storage capacity.

DIRECTOR PFALSER: What are you seeing in the way of storage in the state? Are we increasing in storage naturally, or are you seeing storage leaving the state, being taken out of the state?

SCOTT SEFTON: Unfortunately, I'm seeing it leave the state. A lot of the nationals, I seen them closing a lot of their locations, for whatever reason. I don't know if it's because of loss of business. I don't know. It's unknown to me why. But I do see a lot of the retail locations storage facilities leave.

DIRECTOR PFALSER: Okay.

SECRETARY KEOGH: Kevin -- or Director Pfalser, I think we'll move on and we'll come back to you for additional questions. I know you're very familiar with this industry, but I want to make sure all our Task Force members have time to address the speaker.

DIRECTOR PFALSER: Absolutely.

SECRETARY KEOGH: So with that, I'll turn to Secretary of Commence, Mike Preston, for any questions he --

SECRETARY PRESTON: Thank you, Madame Chair. And thank you, Scott, thank you for coming down --

SCOTT SEFTON: You're welcome.

SECRETARY PRESTON: -- and taking the time to share this info and providing testimony. I think Kevin covered most of these pretty well.

I guess the only thing I would ask is according to your testimony, you mentioned that you weren't able to get your trucks out, obviously the low supply. But were the roads impassable? Was that an issue as well?

SCOTT SEFTON: Oh, yeah. Yes. We was down for, if I remember it, right at seven days.

SECRETARY PRESTON: That you couldn't --

SCOTT SEFTON: We couldn't. No, we couldn't move.

SECRETARY PRESTON: Okay.

SCOTT SEFTON: Now, there was -- of course, we're based out of Mountain View. As you know, the roads are -- it's a little different in our area than it is in Jonesboro. I mean, you know, it's relatively flat, you know. So some of my customers are in Jonesboro and they was able to run bob trucks, you know, like five days into the event, you know, just to select locations, you know.

But yes, we was about seven days before we could get trucks out.

SECRETARY PRESTON: Okay. That was a big factor then?

SCOTT SEFTON: Yes. Very much so.

SECRETARY PRESTON: Thank you.

SCOTT SEFTON: You're welcome.

SECRETARY PRESTON: So you cover, you said, over to Jonesboro. What's your territory? How far?

SCOTT SEFTON: We run pretty much everything south of home down this way, and then we have customers from this area all the way to over into as far as Nashville, Tennessee, and then the northern part of Mississippi.

SECRETARY PRESTON: Big area. Thank you. That's all I have, Madame Chair.

SECRETARY KEOGH: Thank you. I'll turn to Director Bengal and come back and ask a few questions myself.

DIRECTOR BENGAL: Thank you for coming.

SCOTT SEFTON: Yes, sir.

DIRECTOR BENGAL: Listening to some of your answers on the questions that Director Pfalser had, when you say -- when referring to the word "terminal", that means where you go pick up?

SCOTT SEFTON: Yes. We load.

DIRECTOR BENGAL: A distribution point.

SCOTT SEFTON: Yes. Yes.

DIRECTOR BENGAL: And do those have to be along pipelines? I heard you say there is one served by rail, but is that the most economic location, along a pipeline or rail line?

SCOTT SEFTON: Yes. Yeah. Yeah. They are -- well, like we referred to the AmeriGas terminal at -- up here off of Broadway, it is exclusively rail. You know, you have the terminal in Light, the pipeline.

Now, when we're referring to the Memphis refinery, they actually -- there's no pipeline. They actually -- there's no pipeline. They actually produce the propane. We go in and load it.

DIRECTOR BENGAL: Okay.

SCOTT SEFTON: And we also transfer some of that product to the terminals, Light, West Memphis. We bring some over to the port that I was referring to. And then we also load gas out of the refinery and go to different retail locations.

DIRECTOR BENGAL: Okay. So if there were to be terminals located in the western part of the state, for example --

SCOTT SEFTON: Yes.

DIRECTOR BENGAL: -- I'm not familiar with any pipelines --

SCOTT SEFTON: No, sir.

DIRECTOR BENGAL: -- in that area. It would have --

SCOTT SEFTON: It would have to be rail. Yes.

DIRECTOR BENGAL: -- facility. And it would come out of where, Oklahoma?

SCOTT SEFTON: I'm assuming. Yes. Some of the gas that comes into the port over here, NGL port, it comes out of the Dakotas. They even get some gas out of Canada.

DIRECTOR BENGAL: Okay. So is there a particular -- in a terminal situation, I know you're involved with distribution. But is there a volume that a terminal would have to -- that you could, from experience, to make it economic to do?

SCOTT SEFTON: Yes. I would say so. Yeah. You -- you would have to move a certain amount of gallons to justify, you know.

DIRECTOR BENGAL: Is that possible in western -- would there be enough customer usage in western Arkansas to justify that?

SCOTT SEFTON: I would say absolutely. Yes. Yeah. Yeah.

DIRECTOR BENGAL: And when you talk about storage area, are you talking about the storage area for the distribution, as yourself? Or the terminals?

SCOTT SEFTON: Well, actually when we're

talking about the retail storage, it's the storage capacity that they have to pull from, you know, their bobtail delivery trucks to come in and load.

DIRECTOR BENGAL: Right.

SCOTT SEFTON: Most of our customers, they -- well, I have one up in Jonesboro. He has about 150,000 gallons of storage and probably wouldn't hurt to double that, you know.

DIRECTOR BENGAL: And who regulates that or determines that storage? Or is that --

SCOTT SEFTON: That's basically up to them. Am I right, Kevin? The retailer theirselves, you know.

DIRECTOR BENGAL: So there's no regulatory --

SCOTT SEFTON: No.

DIRECTOR BENGAL: -- process --

SCOTT SEFTON: I mean, as long as they have property and can stay within the guidelines of the LP board, I mean they can set as many tanks as they can.

DIRECTOR BENGAL: That's all the questions I have.

SECRETARY KEOGH: All right. Well, thank you.

SCOTT SEFTON: You're welcome.

SECRETARY KEOGH: Again, like the other Task Force members, I want to express my appreciation for you being here, and your patience as we encounter our own challenges this morning.

Can you describe, to me, at least, the nature of your customers, how they're using propane or liquified petroleum products and how that fits within, you know, their life or work during an ice event or storm event? Can you explain the things of the use of the propane?

SCOTT SEFTON: Yeah. Especially during the cold part of the year, it's for heat. You know, and a lot -- well, the power outage here, generators for power outages.

SECRETARY KEOGH: Okay. Do you know if anyone uses propane -- I guess they use it also for purposes of heat, but also fueling cooking and things like that?

SCOTT SEFTON: Yeah. Cook stoves. Yes.

SECRETARY KEOGH: Are most of your customers, are they rural? Urban? A little bit of both? Or how would you characterize --

SCOTT SEFTON: A little bit of both.

SECRETARY KEOGH: So you have propane usage and store it -- customers deliveries?

SCOTT SEFTON: Uh-huh.

SECRETARY KEOGH: In your testimony that you prefiled -- and I'm aware from Director Pfalser's briefings, that supply seemed to be short before the storm event.

SCOTT SEFTON: Correct.

SECRETARY KEOGH: Can you explain what led to that shortage, or at least how that might be avoided in the future, in terms of making sure customers had full supplies that they needed before coming into a storm event?

So could you explain that a little bit? Do you know what led to that storage? Or is that a common occurrence?

SCOTT SEFTON: It's -- it's pretty common.

SECRETARY KEOGH: Okay.

SCOTT SEFTON: Especially over the last -- since we've been in business. And I've been in the transportation business myself for about 13 years now. And since I've been in the business, it seems to have steadily gotten worse over the years. And I think a lot of it is pipeline issues.

But I'm not -- I mean, I hear, you know, talk, but I'm not in that side of the business to really know why they can't get gas up the line, you know.

SECRETARY KEOGH: So there's nothing on your end? If the --

SCOTT SEFTON: No, ma'am.

SECRETARY KEOGH: -- inventories were available to you --

SCOTT SEFTON: Oh, yes.

SECRETARY KEOGH: -- you could be making sure customers were --

SCOTT SEFTON: Yes.

SECRETARY KEOGH: -- full, ready to go --

SCOTT SEFTON: Yep.

SECRETARY KEOGH: -- as they go into the --

SCOTT SEFTON: Yep.

SECRETARY KEOGH: -- winter months --

SCOTT SEFTON: Right. Right.

SECRETARY KEOGH: -- where they might rely on the --

SCOTT SEFTON: Yep.

SECRETARY KEOGH: -- fuel? That's something I think is important as we look at what we can do to make sure that these deliveries occur.

I know the governor did act as a result of information that came to me, as well as to him, that there was this shortage. And knowing that we were entering the winter season --

SCOTT SEFTON: Right. Right.

SECRETARY KEOGH: -- we wanted to get ahead of it. Obviously the storm came quickly after that decision. And also in a more -- slightly more significant way than everyone anticipated.

SCOTT SEFTON: Oh, yeah.

SECRETARY KEOGH: So we -- I think we got caught short there too. So appreciate the work you did during the storm to get out of -- a comment made earlier in our hearings with other organizations was the road conditions --

SCOTT SEFTON: Yes.

SECRETARY KEOGH: -- perhaps limited other deliveries outside of liquified petroleum. Do you know if the recommendation that came, and that was perhaps engaging the National Guard or others to assist earlier or help make sure roads were passable, is that something you would recommend that we discuss or --

SCOTT SEFTON: Yes. I would say. Absolutely.

SECRETARY KEOGH: And I know that in speaking to our National Guard commander, he mentioned that they were on the road and down, I believe, in the Hope area doing -- helping assisting in delivery of propane, I believe, during the storm event.

SCOTT SEFTON: Yeah.

SECRETARY KEOGH: So I know that they were called out during the storm event itself. But I guess, are there other resources that y'all utilize for purposes of keeping the roads open, the counties, or other -- can you think of any additional groups that we might want to consider recommending?

SCOTT SEFTON: Yes. Well, other than the normal highway department, maybe the county road departments could help. You know, open -- because some of our locations that we deliver to are actually off of the main highways. You know, they're on the county roads, you know. And absolutely, those could be cleaned up.

And some of the trouble we had was actually getting in and out of the customers' locations, you know. Maybe we could look at some way to -- because it's left up to them to clean their lot, you know. And unfortunately, some of them don't do a very good job, you know.

SECRETARY KEOGH: So are you -- is your equipment, I guess, if you will, weatherized? Are y'all equipped to go on icy, snowy roads and things like that?

SCOTT SEFTON: No.

SECRETARY KEOGH: In terms of the vehicles?

SCOTT SEFTON: No, not really. I mean, yes, there's things you can do. You can put on tire chains, you know, to -- but that's a lot of work, you know. And it's not really all that safe, to be honest with you.

SECRETARY KEOGH: All right. Well, I appreciate the feedback that you've given, the comments you've got, the patience, again, you had this morning.

And I'm going to turn it back to Director Pfalser. I know he may have a follow-up question from any of these discussions.

DIRECTOR PFALSER: Just one, Scott. When the -- when the pipeline -- this is my understanding -- and you're in the terminals all the time.

SCOTT SEFTON: Right.

DIRECTOR PFALSER: But there was a couple of lines that ran from Mont Belvieu up towards the east coat --

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: -- and came through the state.

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: And I understand that a few years ago that they reversed one of those.

SCOTT SEFTON: Yes.

DIRECTOR PFALSER: And so that cut half the capacity to pull from the pipeline.

SCOTT SEFTON: Oh, yeah. Yeah.

DIRECTOR PFALSER: And so, you know, maybe that is one of the things that has caused on a year-to-year basis.

SCOTT SEFTON: Yeah.

DIRECTOR PFALSER: But then inside the terminals that exist, do you ever have a situation where they have allocation and your customers then don't have product available to them?

SCOTT SEFTON: Oh, yes. Absolutely. Yeah.

DIRECTOR PFALSER: Okay.

SCOTT SEFTON: We had customers this last winter that simply could not get gas because of allocation, and they was forced out of the state, you know.

DIRECTOR PFALSER: So that's when you end up going to -- did you ever go to -- as far away as

Demopolis?

SCOTT SEFTON: Yeah. Demopolis. We ran some out of Demopolis. Yes, Alabama.

DIRECTOR PFALSER: Alabama. Okay. All right. I think I don't have --

DIRECTOR BENGAL: I have a question. Who determines the allocation you're referring to?

SCOTT SEFTON: That is the supplier.

DIRECTOR BENGAL: Okay.

SCOTT SEFTON: The owners of the terminals.

DIRECTOR BENGAL: Okay. So they're just allocating their current supply --

SCOTT SEFTON: Exactly.

DIRECTOR BENGAL: -- spreading it around?

SCOTT SEFTON: Exactly. Exactly. Yeah. Yes.

DIRECTOR BENGAL: When you talked about the pipeline, is that a lack of pipeline capacity or just the lack of product in the pipeline?

SCOTT SEFTON: Lack of product in the pipeline.

DIRECTOR BENGAL: So where it's being produced is just not sufficient to meet the supply?

SCOTT SEFTON: Right. Exactly. Exactly.

SECRETARY KEOGH: Are you aware of any

pricing adjustments that occurred during the time for propane? I know we heard testimony about the impact to the natural gas pricing. Are you in the loop, did y'all have any impact on your financial --

SCOTT SEFTON: No, ma'am. No.

DIRECTOR PFALSER: The pricing that the Secretary is referring to is the wild increases of natural gas when the supply got scarce.

SCOTT SEFTON: Oh, okay. Yes.

DIRECTOR PFALSER: Going to supply.

SCOTT SEFTON: Yeah.

DIRECTOR PFALSER: We saw some marginal increases at the rack, but nothing -- nothing like that.

SECRETARY KEOGH: Nothing that affected your ability --

SCOTT SEFTON: No, ma'am.

SECRETARY KEOGH: It wasn't a price choice of whether you could get --

SCOTT SEFTON: Right.

SECRETARY KEOGH: -- product or not?

SCOTT SEFTON: Right.

SECRETARY KEOGH: All right. With that, I appreciate your time.

SCOTT SEFTON: You're welcome.

SECRETARY KEOGH: And thank you for being here. We're going to conclude -- we have an additional speaker that was going to participate by Zoom technology. They graciously rescheduled to this afternoon as we look to get power restored.

So with that, I believe this will end our morning hearing. And we'll be able to regroup as -- when hopefully full power is restored and technology -- later in the day, or at a possible alternative location. So we have several plans in place.

But thank you for joining us, those of you that are live streaming, and also thank you for those of you that came this morning to participate in this hearing.

(Whereupon the proceedings were adjourned.)

SECRETARY KEOGH: Good afternoon. Today is June 2nd, 2021. And we are here at the Liquified Petroleum Gas building, which is an entity of the Arkansas Department of Energy Environment. And we are here -- assembled to hear testimony for the Energy Resources Planning Executive Task Force.

I am Becky Keogh. I'm Secretary of the Arkansas Department of Energy and Environment. And I have the pleasure of serving this Task Force along with Secretary of Commerce, Mike Preston, Director of the Oil and Gas Commission, Larry Bengal, and Director of Liquified Petroleum Gas Board, Kevin Pfalser. We're happy to welcome Director Steve Sparks who is the AEDC Existing Business Resources Division this afternoon as he is sitting participating today on behalf of Secretary of Commerce Mike Preston. We welcome you, and happy to have you join us.

To begin our hearings, on March 3rd, 2021, Governor Asa Hutchinson signed Executive Order 21-05 to establish the Energy Resources Planning Task Force. The purpose of this hearing this afternoon, along with the other hearings that have been conducted over the last several days, is to gather information from testimony in order to better prepare our state energy infrastructure in the event of another statewide emergency.

And as I said yesterday, this administration, unfortunately, has -- is not -- we have experienced now three 100-year events in the last three years between a 100-year flood event, of course the global pandemic that we've all gone through, and in February the record snow and ice storm that was significant intensity but also significant duration for the state.

So with that, we want to make sure, and I know the governor is committed to make sure the state is as prepared as possible and has worked hard to be prepared in these events, but also looking forward to looking at these events, go through an after-action analysis and assessment with the idea that we can take lessons learned from these events, and hopefully embrace the good things and hopefully address some of the gaps that might have been identified.

So we will be discussing that with folks today during this testimony period. We have organizations that have submitted prefiled testimony. We appreciate the contributions that you made already for the process. And I know the Task Force members have spent time reviewing that testimony, written -- prefiled written testimony, and we'll be asking questions just as follow-up to some of the information already provided.

When I call your name, I'll call the organizations that are present for this hearing. And this afternoon, I will ask each of you to come forward in a certain order. And when I call out the organization, if you would just come up to the podium -- I guess now we have this chair at the end of the table. And just be sure to state your name, title, and organization as you introduce yourself by means of introduction.

That will help us for the purposes of recording this. We have this being recorded. We also have it being live streamed today. And we appreciate Arkansas PBS for allowing us to make this available to the public through their technology on ARCAN.

After you -- we are allotting about five minutes for organizations who -- to provide opening statement, if you will, about your experience or any recommendations you might have. And then after that five-minute period, we will -- I will open the floor to the Task Force members to ask questions. And we've allotted about a 15-minute total window for that for each organization.

I've asked Andrea Hopkins of our staff who is up here in the front to be our timekeeper. She will just gently remind you if the time is getting -- coming to an end. And she will ask you to be respectful for the time limits, as we have several speakers this afternoon, both in person and available on Zoom.

So thank you for joining us in whatever

form you're here. Thank you. We will have this hearing, we will take a short break, and then a second session following this session.

So with that, I would like to recognize our Department Chief Counsel Shane Khoury is here. We also have a number of staff, Tricia Treece and Dan Pilkington over taking notes. They're helping us with the report preparation that's also part of the executive order, and the communications team that's done a stellar job to make sure these hearings are conducted effectively.

And I know they encountered their own perfect storm this morning when we had a power failure at the AEE headquarters building and have had to make some adjustments throughout the day. So with that, the good news is we have -- Entergy worked quite efficiently for the area and the power has now been restored, which is important not only to our operations but also to the surgical hospital and other businesses there that adjoined in that business park.

So with that, I'll move forward and I'll -- the first speaker we'll ask to come forward in this hearing is Craft Propane. And as you come forward, I will also let NGL Energy Partners, give you advice that you'll be the one I call next, so just so everything's in order and make you aware.

Appreciate if you'll just state your name, title, and organization for the record. That would be great.

RONALD CRAFT: My name is Ronald Craft. I'm President of Craft Propane, Jonesboro, Arkansas.

SECRETARY KEOGH: Well, have a seat and we'll look forward to having a conversation.

RONALD CRAFT: I don't think we'll have to worry about the time. I'm not full of gas usually.

SECRETARY KEOGH: Well, thank you for being here.

RONALD CRAFT: Well, thank you for taking part and, Directors, thank you also for giving us the time.

I'll give you a little bio on myself. I've been in the propane business all my life. My father started the business in 1954. I became active in 1978. Took control in 1982. This is our 67th year in business.

I've also been active in the Arkansas Propane Gas Association. I've been serving as Junior and Senior Director through the years, served as President in '94 and 2000. I was appointed by Mike

Huckabee, Governor Mike Huckabee, in 1996 to the Liquified Petroleum Gas Board. I served until 2018.

The propane business has changed over the years, needless to say. We operate out of Craighead County and the surrounding counties, and we also -- we do residential, agricultural, industrial, commercial.

If you look at the letter that I sent in, supply has become increasingly our problem, and particularly since 2013. 2013, the Enterprise pipeline reversed a line that runs through the center part of Arkansas from -- I guess it comes from the Shreveport area and comes up through Little Rock. Moves through Light, Arkansas, goes to Dexter, Missouri.

They were -- there was two lines there. There was a 16 and 20-inch line. The 20-inch line stayed busy all year long and the 16-inch line stayed busy about a third of the time except during the winter. The winter, it stayed full of propane. So all the terminals on that pipeline could pull gas any time they wanted to.

In 2013, they reversed the line, and ever since then it's devastated our supply issue in northeast Arkansas.

Now, I know we're here because some of the dealers ran out of gas, and I'm assuming that's the question. But I want to say that it's not always the retailers' problem -- fault that someone runs out of propane. I was going to explain a little bit about our customer base, and what we -- and our terminology that we use in the business.

You have keep-fulls, which are people you keep on route. You keep them full. They pay their bills. Everything is fine.

Then you have the will-calls, several different kinds of will-calls. Some of them call you early enough that you can get to them before they run out, regardless of the condition. Then you have the ones that call you when they're extremely low. Okay. Then you have the other will-calls that never call until their frigging power goes out. And they don't think to look, even though they've been told that a weather system is coming and the road may get bad. They either don't look or can't afford it. That's the other will-call. So it's not necessarily always a retailers' fault.

Through the years, we've been -- I knock on wood, we've been lucky enough that we've always had supply. I have -- I am not going to say ample storage, but we've made it through it. But we manage our storage as best as we can.

Every time there's room for a load of gas, we put it in. Even at the end of the day, I may run my bobtails in to fill up to make room for another load. And if a miss a load from one supplier or the other, I'll reach out and I'll pull gas from Illinois and Demopolis, Alabama, pull gas from Hattiesburg, Mississippi. Because if you miss a load, it's hard to ever catch back up.

Now, we also try to manage our customer base best we can. And we were aware of this winter event coming up to four weeks prior to its arrival. I subscribe to weather forecasting agencies, and a lot of times they'll tell you six weeks ahead. If it keeps going currently, it may do this. And you follow it every day.

Once we were sure that it was going to arrive, we started running our routes, our keep-full routes, even though they weren't ready, two weeks prior to the event occurring. We could get those customers taken care of and so they're fine through that so we can handle the will-calls when they came in, best we can.

We did not stop running during the ice. I left it to driver's discretion. If they thought they could get in a place and get out, we would let them go. If not, they didn't have to go. However, we're on Crowley's Ridge, we're not in the Ozarks. I'm sure there's lots of places in the Ozarks that you just cannot go with ice on the roads. We had a hard enough time as it was.

And also in this, I wrote that extra customer storage or extra retail storage would be very effective, but with the price of steel where it's at, it may be out of reach for some. And particularly, lately the steel prices have just gone through the roof.

It would be my hopes that maybe some more terminals would pop up here in the state. That AEDC, if I can pronounce it, could maybe help some of these folks establish rail terminals or whatever. Because our issue is running long distances once supply gets short in northeast Arkansas.

And running down to Demopolis, Alabama and back, I suppose a transport could only get one load a day. If he's running 40 miles away to that terminal, he gets six or seven loads a day and -- if it's there to get.

The other thing, and I know it's hard to do, is to get the hours of service waiver lifted sooner rather than later. The weather event arrived on February the 9th and hours of service was lifted February the 23rd. We were already in the throws of the emergency storage, everybody's storage below. And we're already running long distances, so the loads weren't coming in like they should have been or could have been if they had closer storage.

And another thing that might help would be, and the governor could do this, would be public service announcements in such an event as we had last February, urging the people to call ahead before it actually arrived, trying to give us more time.

But we worked overtime hours. We worked six-and-a-half days a week prior to it coming and once it arrived -- once it arrives, then you're -- even though you're running on ice and snow, you've got to run very slow. You can't run at normal speeds. We do run on anything but freezing rain. There's no way anybody can run on freezing rain.

Also when the roads got bad, the transport stopped. Because they'll get stuck real easy and plus, not to mention having a wreck or accident with somebody and the liability issue involved there. It's just not worth their while to do it.

And I'm open for questions.

SECRETARY KEOGH: Well, thank you, again, for your presence and for the information you shared. I think all that is very helpful to us as we consider recommendations. And it's always helpful to get those recommendations directly from a source, such as you who have the experience that you do and what you bring to the table, so appreciate that.

I will begin the questioning today and I just wanted to, again, just beyond thanking you, make sure that we fully understood, you are on the eastern side of the state, sounded like; is that correct?

RONALD CRAFT: I'm in Jonesboro, northeast Arkansas.

SECRETARY KEOGH: Northeast territory? And I think you noted that there was effect of the pipeline system that ultimately affected propane supply to Arkansas; is the correct, to the northeast or to the --

RONALD CRAFT: To the whole state when they reversed that line in 2013 and other terminals could pull at will. That's one reason everybody goes to Demopolis. They're sitting on top of a pipeline that stays full of propane all through the year. And when their storage tanks get low, they stop, light flashes and all the truckers have to wait and they'll load the tanks. Then they start loading trucks again.

SECRETARY KEOGH: Enterprise pipeline did submit some prefiled testimony to us. Unfortunately, they were not able to attend the hearing today or declined our invitation to hear it today, but we hope that we can continue to work with the pipeline companies to ensure that Arkansas is adequately supplied, and that you, as a dealer or whatever your characterization is -- I don't want to call you the wrong thing.

RONALD CRAFT: Jack of all trades mostly.

SECRETARY KEOGH: Okay. Make sure I don't get it wrong. But that you have access to the fuel you need to provide the customers.

RONALD CRAFT: Yes, ma'am.

SECRETARY KEOGH: I asked earlier in an earlier meeting, would you characterize you -- would you characterize what type of customers you're serving? You mentioned some of the will-call. Are they using the propane for residential heating, for cooking --

RONALD CRAFT: For heat.

SECRETARY KEOGH: -- for backup generators, or all of the above? Or can you characterize what the use is in Arkansas as far as energy source? Can you --

RONALD CRAFT: Residential, all of the above. For hot water, for their generators, the heating. In my area, Jonesboro, and if they're in the city limits, the electricity is extremely inexpensive there. So a lot of them are heat pumps with gas backup.

SECRETARY KEOGH: Right.

RONALD CRAFT: They have fireplaces, water heaters, and heaters, and generators. That's what the residential part is. Industrial is forklift cylinders. Commercial are restaurants, churches, what have you.

SECRETARY KEOGH: So the propane gas backup to those on electricity. I similarly live on property -- I similarly rely -- would rely, as far as backup, on propane not a natural gas line, due to its availability.

How do you think the state can be better prepared the next time? You gave us several recommendations. Is there anything else that comes to mind?

RONALD CRAFT: Without increasing the flow of propane at the pipeline or more terminals being built or in different locations in the state, the only thing that in my opinion the state could do would be get hours of service lifted sooner.

SECRETARY KEOGH: But I know the governor asked us -- and I think Director Pfalser, I'll let you address that question, but I know that we were aware that there was a shortage of supply prior to the storm event due to supply or transportation issues; is that correct?

DIRECTOR PFALSER: Correct.

SECRETARY KEOGH: And so there was action taken based on a recommendation from the petroleum commission director that the governor act early. So I know other states have different timelines as well, that they were acting which might have affected some of the Arkansas supply as well.

So anyway, with that, I'm going to turn the questioning over, I believe, to my right to Director Sparks and see if he has any additional questions for you.

DIRECTOR SPARKS: Ron, thank you, again, for being here and your testimony.

Did you run completely out?

RONALD CRAFT: No, sir.

DIRECTOR SPARKS: So your main issue at

that point was just distribution and weather that was related to that?

RONALD CRAFT: Yes, sir. I said I managed to stay in gas all these years. And I say knock on wood, but if it continued on like it was, we probably would have ran out. But we got lower than I like to be, let me just put it that way.

DIRECTOR SPARKS: Would you mind sharing just a little bit about additional terminals location you were talking about? What would you need and where you would you need them in order to have adequate even if this ran a little longer?

RONALD CRAFT: Well, it's not just me. The closest terminal to me is Light, Arkansas which is, I guess, roundtrip 40 miles. Other than that, there's one here -- there was one in Little Rock and they took it down. They do have one, a rail service, here in Little Rock. But that's -- and there's one in West Memphis. I think AmeriGas has a transloader; is that right?

DIRECTOR PFALSER: North Little Rock.

RONALD CRAFT: In North Little Rock. But they don't sell out to independents like myself, just supply themselves. That's about the long and short of it, as far as I know. We pull out of Memphis at the refinery there. But it got hit with the cold weather too and it went down, just like it went down in Texas.

So it was -- that made supply low because basically you've got a pump pumping out of a pond that's not being refilled and it was about to go down. I'm sure that's what happened to the natural gas companies as well. Infrastructure failed there also.

DIRECTOR SPARKS: So in light of the current situation with the bridge across Memphis over there, what does that do to you if you have to pull out of Memphis and can't get to Memphis?

RONALD CRAFT: Well, if it was in the wintertime, it would be devastating.

DIRECTOR SPARKS: Okay.

RONALD CRAFT: It's -- bad as it is right now, takes another hour, hour-and-a-half for a guy to cross there. That cuts way down on how many loads they can haul a day, no question about it.

I did talk to a transporter that said he could run at night. One of them, he said he couldn't sleep in the day, so he had to run during the day. But if they could run at night, they could cross back and forth across the bridge. That might be something that would have to be done if it were such a case as going down in the middle of wintertime.

DIRECTOR SPARKS: Thank you.

SECRETARY KEOGH: Thank you, Director Sparks. I'll turn it over to Director Bengal and see if he has additional questions.

I'll just -- to follow up on your question though, sounds like from what we've heard this morning that we don't really have terminals on the western side west of Little Rock; is that correct?

RONALD CRAFT: Eastern side. I'm not sure what's on the western side.

SECRETARY KEOGH: Do you know if there's anything --

DIRECTOR PFALSER: There's not anything that's in the state.

SECRETARY KEOGH: So that might be an area of focus if, in fact, there was shortages, I assume they get some of that propane delivered out of Oklahoma as well. And I'm aware that, I believe, the military department indicated to me that they were on the ground helping provide propane in the Hope or Texarkana area.

DIRECTOR PFALSER: I believe so. I believe that's right.

SECRETARY KEOGH: They were called in being it was the emergency in that area.

So anyway, with that, I'll shift over to Director Bengal.

DIRECTOR BENGAL: I'll follow up a little bit. Thank you, Ron, for being here. I'll follow up a little bit.

Is the customer base growing or staying the same?

RONALD CRAFT: It's growing.

DIRECTOR BENGAL: Is it more industrial growth or more residential growth?

RONALD CRAFT: Both. I'd say more residential. Construction's going out of the county.

DIRECTOR BENGAL: Okay.

RONALD CRAFT: By far.

DIRECTOR BENGAL: So if additional terminals were to be relocated in other parts of the state, even in the eastern part of the state, is there sufficient customer base to justify someone doing that?

RONALD CRAFT: I would think so.

DIRECTOR BENGAL: What would be the -- just ballpark, what kind of investment would somebody have to make to put in a terminal you're talking about?

RONALD CRAFT: I have no clue. You're the Oil and Gas Commissioner. You tell me what the cost is for the pipeline.

DIRECTOR BENGAL: Just from a construction standpoint?

RONALD CRAFT: I would say millions.

DIRECTOR BENGAL: Is that in the facilities for storage or a rail spur?

RONALD CRAFT: Storage. I guess, storage and that's would be -- try to locate on a spur to existing, that way it wouldn't cost too much money.

DIRECTOR BENGAL: Otherwise, the cost would just be in tankage, loading equipment?

RONALD CRAFT: I'm not sure what a -- let's see, was it 120,000 gallon tankers was 400,000 that was built, or 500,000 when it was built?

DIRECTOR PFALSER: For that large storage that was being considered? It was way up there. Yeah. And you know --

RONALD CRAFT: One tank. That's one tank.

DIRECTOR BENGAL: Okay. I was just looking at what kind of investment, if you're going to look at incentive to do something like that, what was that ballpark.

RONALD CRAFT: That, I'm not familiar with.

DIRECTOR BENGAL: Okay.

RONALD CRAFT: It would be several million dollars though. Light, for instance, I think has ten 9,000 gallon tanks and they're at the pipeline.

DIRECTOR BENGAL: Right now, the cost of steel, that's more than it was two years ago.

RONALD CRAFT: Yes. And the backlog probably for -- well, domestic tanks, I ordered some, I guess, month-and-a-half ago, to be constructed August.

DIRECTOR BENGAL: Okay.

RONALD CRAFT: And cylinders right now, DOT cylinders for 100-pound so and so forth are -- they're way out there. I ordered some forklift cylinders, to be built January 4th.

DIRECTOR BENGAL: Okay. So we're talking about long lead times to address those?

RONALD CRAFT: Uh-huh.

DIRECTOR BENGAL: Thank you.

SECRETARY KEOGH: Director Pfalser, we'll wrap it up with your -- I think any questions you might have. And want to make sure we get to the other witnesses. I appreciate it.

DIRECTOR PFALSER: Ron, the only question that I have -- and you know, we've visited throughout the weather event and everything going on. And you manage your customers very well and were fortunate to stay in gas.

Do you see a some -- kind of advice or even a form of regulation coming from the board at some point, a direction to allocate at the dealer level? If -- if supply is short and you're filling all of your customers' tanks, then you're limited -- you're limiting the number of people that you can get gas to.

Do you think that there would be any -- any reason to consider something along the lines of, okay, we're now on allocation, we need to limit the number of gallons that we deliver for a period of time to get more people gas? Or do you see that as something that is not really feasible?

RONALD CRAFT: I don't see where that's feasible. Dealers will limit its deliveries itself. And we have, in the past, 2013 as a matter of fact, limited our deliveries, amount of gallons, cut them in half what we normally did to ensure supply.

This past year, I did that for about an afternoon until I could secure extra loads, know where it was coming from. Then I opened back up again.

DIRECTOR PFALSER: Okay. I think that that's the only question I have beyond what he had shared.

SECRETARY KEOGH: Thank you so much. I appreciate your time again. And the follow-up question I'll ask several of you in the room today is just, I know propane -- we talked about the customer use of it appears more residential. Is there a commercial use of propane?

RONALD CRAFT: Yes, ma'am.

SECRETARY KEOGH: And is there a potential for propane to help us when we have natural gas shortages? Or is that something that's not really a suitable thing? It's either one or the other it sounds like.

RONALD CRAFT: Well, that was curious to me. Because in the '70s and '80s -- or '60s and '70s there was a lot of standby systems built in the industrial plants, but in the '80s they started selling them off.

SECRETARY KEOGH: Okay.

RONALD CRAFT: And I'm assuming the natural gas people said we'll be able to handle it, you won't -- we won't curtail you. I never did -- it's a -- I guess there's still some -- is there still some standby systems?

DIRECTOR PFALSER: Not many.

RONALD CRAFT: Not many. Most of them are gone.

SECRETARY KEOGH: Probably the cost. I know that natural gas isn't very expensive. I know the cost factors, I guess, propane would follow the same cost model.

RONALD CRAFT: Just availability, I think, at the time, being able to have enough pressure to, say, push gas up to my area from -- on natural gas pipeline. But you know, this wasn't the first year they curtailed the industry. It's happened before.

SECRETARY KEOGH: All right. Well, thank you, again, for your time and look forward to working with you in the future through Director Pfalser. And let us know how we can be of support.

RONALD CRAFT: Yes, ma'am. Thank you very much.

SECRETARY KEOGH: Thank you for coming forward today.

At this point I'll ask NGL Energy Partners to come forward and make a presentation. I was remiss in my earlier recognition to introduce Donnally Davis, our director of communications back here. I mentioned her team, but I know she keep -- she's a great leader of that effort. And I appreciate all the work she's done, especially today, and previous days. Thank you for joining us.

And I'll turn the room -- or the mic that -- we don't have a mic, but to you.

AARON REESE: My name is Aaron Reese. I am Senior Vice President of Liquid at NGL Energy Partners. The -- we work closely with Mr. Craft, so when you were discussing, you know, some of those areas, we are actually -- you have your producers and then you have your midstream people that are the ones that are getting it from A to B, and then you have the retailers that are getting it into the users. We are that midstream portion of that product, where we are taking it from A to B.

So if you flip to the second slide -- and if you can blow that up just a little bit on the -- are you in PowerPoint when you're doing this?

MR. DEAL: I am. I don't know that I can blow this up.

AARON REESE: Go to the -- go to Slide Show.

SECRETARY KEOGH: It's probably under your top bar over to the right.

AARON REESE: So again, as Ron was saying, the black line that's represented here is the TEPPCO pipeline which is owned by Enterprise. The star that's at Little Rock is actually a rail terminal that we built within the last five years, I believe, Kevin. And then the Light terminal is actually on the TEPPCO pipeline, as is the West Memphis terminal. And then just across the border up in Dexter, Missouri is another one.

As Ron also indicated, we used to have a terminal in what we call Rixie, which was North Little Rock, which we actually did decommission just in the last year because it literally sits in a swamp, and the pipeline that was connecting it from the pipeline up there was just becoming unsafe, in our opinion. And so we decided to decommission that terminal.

So as you can see, those terminals, each have a significant amount of storage at each location. So the terminal on the Memphis one is indicating the Valero refinery that sits there, which we also take 100 percent of that propane and market it for Valero as well.

So a lot of times, we'll truck product that's not being consumed in the local market at

Memphis, we'll truck it to Little Rock, we'll truck it to Light, we'll truck it to West Memphis, we'll truck it up to Dexter. So in addition to Light, West Memphis, and Dexter receiving by pipeline, we'll also receive by truck at those terminals.

Little Rock can receive by truck, but that, of course, is primarily by rail, which I'll go into a little bit more on the next slide.

So I know that map's a little small on the right, but you can see -- if you squint really well you'll be able to locate Arkansas in there. So the TEPPCO pipeline is fed down from Mont Belvieu, Texas, which is the termination of that line down in the south.

And as Ron indicated, when the shale revolution occurred out in the east, they stopped shipping propane most -- I mean, it really started to originate for the east, more in the Ohio, West Virginia, Pennsylvania market. And so the pipeline became very underutilized.

And as Ron indicated, before that time, that pipeline was filled with propane. So you pretty much could, whenever you wanted, you opened up our spigot at our terminals and you could come in, fill our terminals, and go on.

Well, now it's a batch pipeline. And so we have to serve competition with refined products that are also in that pipeline, so we have to create batches within that pipeline in order to do that.

Well, the problem is that sometimes we can't fill our terminals because we are the only ones that are sending batches at certain times up that line. So you can't receive off the pipeline quick enough to fill the terminal up, right. And so that's been somewhat of a limiting factor starting back, as Ron indicated, in -- around that 2013 timeline.

The other thing on a pipeline, we have to nominate before the 15th of the month prior. So as he said, we kind of started to see the cold weather event coming, but it really wasn't as for certain as you'd like to have thought by the 15th of January, which was actually a warm January, if you kind of remember. And so our forecast was probably a little off, which you're going to see in the next slide, but we'll hold here for just a second.

Shipping cycle, so again, as we're serving that shipping cycle, it happens every ten days. So they can create a batch every ten days but that isn't guaranteed that we can get on each batch coming out of that Mont Belvieu, Texas market.

Again, because we -- just like you were all talking about allocating to your customers, we are in allocation on the pipeline. So we are fighting for that allocation space on that TEPPCO pipeline in order to ship product up there.

The transit time for products originating in Mont Belvieu which is the only point of origination for that pipeline is in Mont Belvieu and it takes about 10 days to 12 days to get it through the state at that point from start to finish.

For rail, our rail terminal in Little Rock that we built, some product can come out of Conway, Kansas. Which if you're looking straight in the center of Kansas, that's where Conway, Kansas is at. It's a major underground storage location. We're able to ship product there by rail.

Also the Bakken, which is North Dakota, another shale area, that gas up in Bakken kind of the western North Dakota area is another origination for gas. And then some will come out of Chicago, Illinois out of those refineries, and there's pipeline feeding that market as well.

So as you can see there, there's transit times on that as well. So again, we kind of have to forecast many days in advance from your origination.

And even once you forecast, let's say you're sending 20 cars to a terminal. Those aren't all going to ship on the first day of the month. They're actually going to spread them out the entire month and you're going to receive them -- some that ship in February aren't going to receive until March, right, because you're serving 10 to 15 days out of Conway, 15 to 25 days of Bakken, and 7 to 10 days is how long it takes a rail car that starts in those markets and ends up at Little Rock.

And then trucks, there are some additional options for truck. You've got refiners in Memphis, of course, which was discussed. The Coffeyville refinery up in Kansas, we actually take 100 percent of that propane as well. And that will sometimes make its way into northwest Arkansas. So that's another market that can feed that.

There's a refinery in Tulsa that will make it into this market. Wood River, also up there, Phillips refinery up there could make it into this market sometimes. And also El Dorado.

The pipelines, there's additional pipeline-fed locations. We actually own the terminal is East St. Louis, Illinois. Sometimes that gas could come down.

Carthage, Missouri is actually fed by pipe. There's a cavern there. That's in the southwest corner of Arkansas. We have --

DIRECTOR PFALSER: Missouri.

AARON REESE: Excuse me, Missouri. And that will often make it into northwest Arkansas. And then as Ron indicated, Hattiesburg, which is a storage cavern location which feeds the pipeline that feeds Demopolis, that gas will make it up into this market. And then also Target owns a terminal down in Greenville, Mississippi that will make it up into this area as well.

So there's -- Arkansas is a good market in the fact that they have influence from a lot of areas, but some of the issues that you do experience is the west part of Arkansas, there's no pipelines. And that make -- sometimes can make it difficult.

The other thing that is an issue right now in the rail is that when the rich shale gas first started going, the economics of rail -- shipping rail gas into this market was very favorable, even more competitive than shipping it by pipeline. But those markets have kind of balanced out as there's been more export opportunity and other homes for that gas.

And so getting rail into this market

economically, especially to compete with pipeline gas or refinery gas, is very, very difficult, which is why we have a -- we have a very nice terminal that we built in Little Rock on that rail terminal that is underutilized because of that exact reason right there.

Next slide, please.

So we all know what happened in February. But one thing that I thought was interesting is February '21, the heating degree days, which is the time that the temperature's below 60 degrees was 815. The five-year average is 546. The 20-year average is 487. So it wasn't our imagination. It was definitely cold in February, right. Our sales in February were 25 percent higher year over year in that area.

Hazardous roads did make it difficult, as Ron was indicating. There was times where trucks just couldn't get on the road. And then a couple things to make things worse, the batch that was supposed to start at the beginning of February was delayed a week because they were having issues because they couldn't pump product because they were having all -- I mean, it was just right -- Texas was suffering, right.

So that was a big issue, that the pump that was supposed to come up didn't get started for about a week later. And then there was a small explosion at the Valero refinery on February 15th that shut propane production down until March 9th, so it couldn't have happened at a worse time. So it was definitely a perfect storm of activity that occurred kind of all at once.

The next slide.

So my personal recommendations actually align very well with what Ron had said. I think if I -- if you went back to that original slide and you looked at the amount of storage that we have at our locations, the West Memphis terminal, by far, of all the assets that we own has the most storage of any asset that we own in our entire system, and we own 27 terminals.

So we could add storage. How much would that be? We could add two 9,000 tanks at Little Rock -- excuse me, or at Light, if we wanted to. I think there's a much greater impact if you had 20 customers had 30,000 gallons of storage at each of their individual retail locations because you can spread it out more. They can prepare more in advance.

Already indicated that sometimes we have a hard time filling the storage we have due the batch-size restraints we have. So to me, something of low-cost loans or subsidized loans to make it easier, especially with the price of steel right now, to incentivize retailers would be helpful.

I know that Michigan is doing that right now. They're doing low-cost loans, even doing a little bit of loan forgiveness for that type of thing.

Carriers, in addition to -- I know you guys actually -- the State of Arkansas did do a nice job of getting the extension of hours in very quickly. There might be another opportunity for gross vehicle weight waivers, to where you can allow them to load a little heavier, allow bigger trucks to come into the market sometime.

But I think there's an ongoing issue in Arkansas that we have seen, and I know that we actually have a carrier company that's probably participating in the call, but we believe there's a carrier shortage in Arkansas.

And again, it kind of goes back to how you're incentivized. Partly could be a driver shortage because if you could go drive from FedEx over in Memphis, not have to drag a propane hose, not have to have your HAZMAT certificate, not -- I mean, not have to deal with that hazardous material and drive a truck, somebody else loads it in the back with a forklift and you go on down the road and probably get paid more, a driver is going to gravitate to that, right.

So I don't know. I don't have the answer to that. And I usually tell people, don't bring up problems unless they have answers. Well, I just did. I broke my cardinal rule, right, where I brought up a problem but I don't know that I have the answer. And I don't know that the state can probably address that. But I do feel like we do have a propane carrier shortage as well.

So that concludes my comments and I'm open for questions.

SECRETARY KEOGH: All right. Well, thank you so much, again, for being here and giving us that full perspective of the operations.

And as I mentioned earlier, Director Pfalser has been educating me through the process of propane. I have familiarity, just through my own career in the refining side as a result of being an engineer and working in the refining industry, but the delivery side of it, I'm not as familiar with. So he has made us aware of some of the challenges we have in Arkansas, and some of dynamics that have occurred in the marketplace that might drive some new challenges. I'll leave that to him.

Do you have any thoughts around how we might improve, I guess, the prioritization of the pipeline for Arkansas? Is there -- I know you're not the right company to ask, but since they're not present, I guess, is there a way for us to incentivize this larger pipeline operation to make sure Arkansas is a priority for them?

AARON REESE: No. That's a -- that's a very good question. We were actually concerned for a while that Enterprise could actually delete the propane tariff with the TEPPCO pipeline for a period of time. But then back to refined products days, Magellan building that refined products line coming into North Little Rock, I think, saved that from happening. So that created more capacity, available capacity on the TEPPCO pipeline in our opinion. So that -- that was a good thing that happened.

But at the end of the day, pipelines are about keep -- got to keep the pipeline moving, right. And you have to have a home for the product when it's going there. So part of the issue is back to, even if we could create larger batches, we still wouldn't -- we may fill up all of our terminals, but the problem is you have too much gas then at that point, that has now gone past Dexter, Missouri which is the last terminal until you get to Seymour, Indiana. And so -- and then we also own another terminal at Lebanon, Indiana that's on the TEPPCO pipeline.

So you've got Dexter, Missouri, Princeton, Indiana, Seymour, and then Lebanon. Those are the only terminals that are really being fed gas from the south at this point. So if those terminals do not need gas past Dexter, Missouri, there's not a home for that gas. And then it has to continue on to the northeast which is not economical because there's much cheaper supply being created in those northeast market, those shale locations.

So I think that one thing that we -- we always try to do is try to encourage customers to always lift in the summer as much as they can. But Ron can attest to this better than anybody, there's not a lot of demand. So you're trying to earn your allocation portion of that pipeline to the greatest extent that you can.

So it's all about earning that allocation on the pipeline, which, again, there's only so much that you can get at that point.

SECRETARY KEOGH: Sounds like from his recommendation of maybe PSAs encouraging customer to try to fill sooner, earlier in the season, if that's an option. I guess, there's no risk of filling too soon.

But would that help spread out the demand.

AARON REESE: It would. But again, I think you need additional storage at that level. Otherwise, they'll run through their supply fairly quickly.

And that's -- I know that's not a solution that -- they can't continue to add storage because at some point, then you run into working capital issues, right. A lot of times they don't have the working capital to fill that storage at that point, right.

And so -- and then the other thing is, if they had gone and they would have filled all that storage going into this weather event and it didn't materialize, then they would have been stuck with a lot of high-priced inventory as well. So he can attest to that better than I can.

But it's a juggling act, right. You've got to try to balance that the best that you can.

SECRETARY KEOGH: Thank you. That's very helpful. I'm going to turn to my right, Director Sparks, see if he has any follow-up questions as well.

DIRECTOR SPARKS: Yeah. Again, thank you for being here. Got a couple questions.

With the batch, with regard to how the batches work, is each -- and the time span that it takes, is that due to priority or volume or volume based on priority or vice versa? Or is that actually just the time it takes to move it through there?

What determines the batch time and the frequency that you can get the batches?

AARON REESE: Very good question. And if I get too technical, just wave your hand. So I said that batches are done in ten-day cycles, right. And so whenever we create a batch, it has to be large enough -- typically, the minimum size batch that they used to want us to do is 50,000 barrels. Which, if you do the math, that's like 2 million gallons. So we -- that was, like, the minimum batch size that they've allowed.

Over the last couple of years, they've been working -- to their credit, they've been working more and more with us to try to get those batch sizes larger. But typically, the minimum that we can create is about -- just to go to Memphis --

So if you think, if you remember the picture I showed you, you've got the main line and then it splits off at the gray junction and it goes over to Memphis at -- West Memphis at that point, to our terminal over there.

We have to have a minimum of 18,000 barrels to make that turn, okay, which is about 750,000 gallons. And the reason is that you have isobutane on each end of that, and then refined products. And so you create this interface that gets very costly.

You have to figure out something to do with it. If your batch sizes are smaller than that, then you've created interface that's very expensive at that point. So you have to get enough gallons together that you can receive everything that they're shipping you back to that. If it goes past your terminals, then it's very costly again. So whatever we create, we have to be able to receive.

And we have to receive a minimum of 750 going to West Memphis, and then between the other two terminals at Dexter and Light, it's usually a minimum total of 15,000 barrels which is 600,000 gallons.

So we have to receive a minimum of 600,000 gallons between Light and Dexter, we have to receive a minimum of the 750,000 gallons at West Memphis as we receive a batch. So that's part of the issue that we have, to time that. We have to make sure that we can receive it.

And then even if we can receive it, sometimes they'll say, okay, yeah, you're on Cycle 7; oh, no, now it's getting pushed to Cycle 8. Because they're constantly managing the same thing on the refined products side as well.

DIRECTOR SPARKS: So you get bumped potentially up the line somewhere --

AARON REESE: Absolutely.

DIRECTOR SPARKS: -- if you don't have volume?

AARON REESE: It can come backwards, newer, earlier, but a lot of times then you're risking, can we hold the product at that time.

DIRECTOR SPARKS: Gotcha. Second question I had was, as drivers/carriers, is it a driver issue, you think? Or is it a carrier distribution system shortage that you perceive?

AARON REESE: That could be a better

question for Gammel, but I do think that it's a little bit of both. I think, again, it's kind of building a church for Easter Sunday, right.

If you've got -- if you have a bunch of propane carriers that aren't doing anything in the summer months, then you've got to find something for that tractor to do, otherwise -- or that trailer, right. So I think there's a little bit of that, but I do think it's a little bit of a driver thing sometimes as well.

It probably depends on the economy. With the way that Amazon is working right now and mailing stuff, I'm sure there's a heavy need for drivers doing that, especially out of that Memphis market.

DIRECTOR SPARKS: Seasonally --

AARON REESE: Seasonally is a problem.

DIRECTOR SPARKS: -- I mean, that's a situation that messes up that flow.

AARON REESE: Absolutely.

DIRECTOR SPARKS: Thank you.

SECRETARY KEOGH: Director Bengal, would you like to follow up? And we'll wrap it up.

DIRECTOR BENGAL: Just a couple things. Does NGL operate a pipeline except that small one stated for propane? You operate a natural gas pipeline?

AARON REESE: We do not operate any natural gas pipelines. We do operate a crude pipeline that goes basically from Colorado down to Cushing, Oklahoma. And then we are in the process of operating a pipeline that goes from basically north of Detroit up to the Traverse City, Michigan area as well. And then that will be a propane pipeline.

DIRECTOR BENGAL: So when you nominate a batch on the TEPPCO line, you're basically buying space on the line?

AARON REESE: Correct.

DIRECTOR BENGAL: At that point in time you own that product in the line?

AARON REESE: Correct.

DIRECTOR BENGAL: So you have to have your market at the other end?

AARON REESE: Correct.

DIRECTOR BENGAL: So you're making a judgment call as to how much will get to the terminals that serve the customers here in Arkansas?

AARON REESE: Correct.

DIRECTOR BENGAL: So if you're off on that, there is no gas for the residential purchasers to go pick up?

AARON REESE: That is correct. And if you went back to the slide where I showed the transit time, again, we're making that determination, at the latest, by the 15th of the month prior.

And at that time, the cold weather event was kind of coming in, but it wasn't necessarily for sure. And so I'll be honest with you, underforecasted. But again, it's because if you based it off of last year's heating degree days, which was not even close, we were not correct in that. So we definitely underforecast in that period, but we did it based upon the information we had at the time.

And the Memphis refinery going down in the middle of that couldn't have happened at a worse time as well because, again, any excess would have made it back into Arkansas as well.

DIRECTOR BENGAL: So the flexibility of fuel availability, there's a lead time that has to be based on predictive weather, predictive events which makes that very difficult?

AARON REESE: Correct. And the issue you have on rail is, rail terminals are typically going to have nowhere near the amount of storage that we have. And typically, it's going to be -- if anything, you may store full rail cars, but it just depends upon the rail siting that you have, right.

And so making those determinations far enough in advance on rail can be very difficult. And again, if I went to Chicago and said, oh, this is -- February 1, this is looking very, very cold; I'm going to order an additional 20 cars to go to Little Rock, Arkansas, well, as I stated earlier, those 20 cars aren't going to ship February 2nd. They're going to ship one on the 2nd, one on the 5th, one on the 10th, you know what I mean?

So even if I tried to buy additional gas to react at that point, it's too little too late.

DIRECTOR BENGAL: So given those lead times and given the risk you are taking as the product owner at that point in time, in that transportation network, is it even economically viable to build additional terminals, which all that does is continually expose your supply risk?

Might make it easier for the retail industry to go get theirs, but how feasible it from a supplier of the gas?

AARON REESE: That's a great question. This is the -- you're, like, sitting in our supply meeting every week, because we have that discussion, especially about Arkansas. Because Arkansas can tip very, very quick in February. And then if we overship, we are -- we have shipped at the highest price of the market and then we're sitting on that inventory for the rest of the summer.

And then we literally won't take another pipe batch until October at the earliest, more than likely November at that point. So we rode the market all the way down, if we do that. So it can be very costly if we don't predict that correctly. And we don't have a way of hedging off that backwardation of the market either. There's no -- unless someone is smatter than I am, we haven't figured out how to hedge the backwardation when it comes to that. So we try to -- we try to predict as closely as we can.

DIRECTOR BENGAL: Given that, would somebody build more terminals?

AARON REESE: I think the problem you have is that -- when I look at the map and if I was to throw a dart, maybe you can think, oh, look, at the big void in western Arkansas. But the problem is, again, you've got a refinery in Tulsa that's got to get rid of its gas. So competing with that refinery becomes difficult, right.

And then your rail terminals aren't going to build as much storage anyway. The rail terminals just don't have the amount of storage that you do on a pipe because you're not receiving large batches at that point.

It's not to say that somebody couldn't, but it would be very cost-prohibitive, I believe, to do that. Just like when we looked at rebuilding the terminal in Little Rock to replace the Rixie terminal, I had back and forth e-mails with Kevin around this as well.

We looked and looked and looked at that. And because the amount of volume that came through that facility, we couldn't justify to do the cost -- to do that, which is why we kept our rail terminal there and then tried to make sure we had adequate ability at Light in order to feed that market.

DIRECTOR BENGAL: Thank you.

SECRETARY KEOGH: Director Pfalser, would you like to wrap up?

DIRECTOR PFALSER: Sure.

SECRETARY KEOGH: I will -- before you start, I will say the next presentation will come from the Arkansas Propane Gas Association. You're fine. Go ahead.

DIRECTOR PFALSER: So earlier you were

talking about allocation on the pipeline. So what months do you build allocation on the pipeline?

AARON REESE: TEPPCO is now a 12-month rolling allocation basically. So you -- used to, back in the old days, which I'm showing my age, you would -- what you lifted in the summer kind of unwound in the winter. So you got -- what you lift in summer gave you allocation in the winter.

DIRECTOR PFALSER: Okay. That was still my assumption, but that's not the way it is?

AARON REESE: TEPPCO is a 12-month rolling allocation. But again, the bigger issue is gas -- motor gas is shipping year-round, so we're fighting for that every month.

DIRECTOR PFALSER: Okay. So if you are -- if you're pulling and you control all the -- all the gas that's coming off the Valero refinery?

AARON REESE: Correct.

DIRECTOR PFALSER: And what -- I've heard that's around 20 loads a day, is that --

AARON REESE: It's actually closer to 11. It can get down to 8. It can get as high as 15, but average is about --

DIRECTOR PFALSER: Okay. I was way overshot.

So does that hurt you in respect of -- to Enterprise, you taking that gas in the summer? Do they look at that and does that hurt your allocation then on the pipeline for later?

AARON REESE: It could hurt it some because it is taking away from allocation that we would earn anyway. But the amount of gas that the refinery is kicking off, we typically would not ship another batch until October because we'll try to fulfill our winter needs, try to time that just right in this February time frame, maybe the beginning of March. And then whatever gas we have there plus supplemented by the refinery typically will get us through the winter -- through the summer.

DIRECTOR PFALSER: Does NGL, do y'all have any transloading operations?

AARON REESE: We do. The issue with transloading operations is that load times are -- take a significant amount of time. We can load a truck, you know, in that 25 to 30-minute time frame. To load a transport off of a transloader is typically going to take you at least an hour.

Then you have issues if you're going to be a commercial transloader, unlike AmeriGas in Little Rock where they're just -- they don't really care how much went off of the rail car in the truck because they're typically doing it for themselves, we need a way of being able to -- you probably won't be able to meter it on us. You need a way to scale, right. So you need a scale in close proximity to do that.

Then the other issue is that you don't have storage. So it's not like you're unloading the rail car into a fixed storage that then you're loading out of. You're loading right off the rail car, so you're dependent upon the rail that's on the track at all times.

DIRECTOR PFALSER: Right. And so -- how many cars can you put on your spur in Little Rock?

AARON REESE: We can hold, I believe, it's ten on and another ten off. And then we can unload four cars at a time.

DIRECTOR PFALSER: So you're limited to the size of your spur as to how much --

AARON REESE: Absolutely.

DIRECTOR PFALSER: And is it safe to say that one rail car is about two-and-a-half transport loads, something like that?

AARON REESE: Correct. It can be a little bit more. It's about 30,000 gallons. So you can fill three trucks off most of the time.

DIRECTOR PFALSER: Okay. Okay. And I think -- I think that that's all the questions that I have. We appreciated you all supporting us. You can see that it -- the western side of the state is an issue. And of course, when the -- when the refinery -- I didn't realize that it was an explosion. I just figured it was part of the weather because it affected Ponca City. It affected Tulsa.

What line feeds the Carthage terminal?

AARON REESE: It's actually a line -- there's a line that goes to El Dorado, Kansas. And then that is the start of the Magellan pipeline that, again, is a refined products and propane pipeline that serves that Carthage terminal. And then there's a 200,000-barrel cavern that we lease from Magellan.

DIRECTOR PFALSER: In the Carthage area?

AARON REESE: In the Carthage area.

DIRECTOR PFALSER: Now, was there a point where Carthage went down because of the weather during that time?

AARON REESE: They were having -- it slowed down, but it didn't completely go --

DIRECTOR PFALSER: Okay.

AARON REESE: Now, we actually ran out of Carthage as well, because the demand got so high that we did run out of Carthage. And then, again, we're subject to batch times at that point.

DIRECTOR PFALSER: Gotcha. I appreciate you taking the time to run over and be with us.

SECRETARY KEOGH: Thank you so much. I guess I have a final question. I know we're running short on time, so I'll keep this brief. Keep your answer brief.

The western side, we talked about that. There's no pipeline then in the western part of -- the eastern part of Oklahoma or Texas that serves Arkansas?

AARON REESE: Correct. If you look at the line --

SECRETARY KEOGH: A pipeline or serve another --

AARON REESE: If you look at the lines represented on that map on the right, those are the only propane pipelines in the United States.

SECRETARY KEOGH: Okay. So this is --

AARON REESE: And we ship on every one of them.

SECRETARY KEOGH: I just was curious, I know siting terminals are challenging. Siting pipelines can be even more challenging for both an investment and an environmental standpoint.

Is there thoughts of additional pipeline?

AARON REESE: No. It would be not cost-effective to do that for sure. So there --

SECRETARY KEOGH: Just wanted to clarify that.

AARON REESE: The pipeline that is up in Michigan, the yellow one, which is the one I was referring to previously --

SECRETARY KEOGH: Right.

AARON REESE: -- we actually recommissioned an ethane pipeline in -- and turned it into propane. So you could maybe find that in some areas where a pipeline is no longer being used. But if it was a refined products pipeline, it would have to meet pressure specifications. That could be hard sometimes.

If you found a natural gas pipeline, you could recommission a natural gas pipeline, but those have a tendency to not be decommissioned typically.

SECRETARY KEOGH: Right. Thanks so much. Appreciate all the great information.

At this point I'll ask American -- I'm sorry, Arkansas Propane Gas Association to come forward (indiscernible) --

THE REPORTER: I can't hear --

LANEIGH PFALSER: My name is Laneigh Pfalser. I work for Capital Partners which represents the Arkansas Propane Gas Association.

So leading up to the week of February 14th, the propane industry began making plans to combat the effects of severe weather. Some dealers did a great job of making sure their customers had propane, while others struggled to do so.

One of the most influential aspects of dealing with this adverse event, though, was the governor's willingness to waive the hours of service requirements. As a personal note, I dealt with my peers and colleagues in the surrounding states and let's just say, I'm very grateful to our administration with the -- our interactions were very positive.

So when the roads became that hard to navigate and the bobtails and transporters were waiting so long at the terminals for product, the hours of service waiver was a critical component. We talked a little about how critical that was. It helped keep our citizens safe, warm, and alive in their own homes. And I want to thank the Hutchinson administration for their support with that endeavor.

But regardless, the members of my association did face other issues during this time. And we've asked one of our members, Hardy Thompson with Island Energy, to speak more specifically about his experiences during the storm.

And at this point, I think I'd like to turn it over to him.

SECRETARY KEOGH: Thank you. Thank you for joining us as well.

HARDY THOMPSON: You're very welcome. Can you hear me?

SECRETARY KEOGH: Yes.

DIRECTOR PFALSER: We can.

HARDY THOMPSON: Okay. My name is Hardy Thompson. I founded Island Energy about 12 years ago. I come from an electrical utility background. Got an engineering degree. So we kind of look at the propane business, you know, differently than a lot of marketers do. Because I wasn't born into it. We're not third generation. So we kind of got to build it from the ground up.

What we're talking about now is what happened in February. We did a pretty good job with our people. We never ran out of gas. Ron touched on the different types of customers, and that's really pretty critical, in that the complaints that you may not have got.

Keep-filled customers, we extensively use tank monitoring to where we know what they've got in their tanks at all times. In fact, that pretty much saved our good customers this past winter because I already had monitors on all their tanks. We've gone to 100 percent keep-filled monitors on our tanks.

We try to limit call customers actually. If we've got a customer and we sat an Island Energy-owned tank, they're going to be a keep-filled customer with a monitor, no exception. So it kind of eliminates all those unknowns that the call customers cause.

Now, that's a different direction than, you know, historically propane companies do. But I just -- I feel like that's a better way to go and I really haven't got any pushback from our new customers.

And then there's a whole other type of customer. There's a customer that owns their own tank. They call around every year to find whoever is cheapest in their view and they'll buy -- they'll buy gas from them. But when that happens, I mean, nobody's really obligated to that customer. And that's what it really takes.

You need to have a relationship with your propane supplier in order to get service during times like this. There was about a week that we refused any new customers. There was about a week in there that we were only taking minimum amounts to our customers because trucks had stooped. We only had so much storage sitting. And it was, you know -- we have obligations to our customers to service them.

And so there was many, many different phone calls I took from people that were, you know, bordering on being desperate, that said, hey, you know, I've got so-and-so's tank, can you bring the gas? I'm like, well, no, for one, I can't fill somebody else's tank.

And even after the emergency effect went into order when we could fill up people's tanks, there were times that I couldn't because I was needing to take care of our own customers.

And to circle back, what happens when somebody owns their own tank and uses various different suppliers, those people would call and say, hey, I got gas this summer from so-and-so, I own my own tank, just bring me some gas, I don't care what it takes. I'm like, I can't do it. I've only got so much gas that my existing customers have helped me earn an allocation from NGL, the people we just talked to, and I've got to distribute that on my own.

And it was just -- it was really sad. Basically told them that the best choice of action they had was to call who they had been buying gas from and tell them their situation and tell them they needed to bring them some gas. And you know, I hated being in that situation. I was there for seven days.

When I say seven days, it's because -- it's because it was a full week that transport trucks couldn't run, that we were just relying on storage that we had in our bulk facilities and our trucks. And so it was a rough time. But it's a success story for us. We've gotten a lot of new customers because of, you know, our mindset of taking care of our people.

So as far as what we can do different, I think more on-site storage at our place and other marketers is probably a good idea. Now, does it necessarily make economical sense? No, it does not. Otherwise, we would all have 100,000 gallons of storage just sitting everywhere we wanted it.

Everybody's kind of got the storage they need based on historical use. Well, this was just not a normal February. We bought most of our gas from the NGL refinery and that hit us very hard when the refinery went down. Luckily, we worked out other things with NGL and other suppliers that weren't NGL up in Illinois and Missouri, and we were able to get gas brought in. But the refinery going down really hurt us.

From my electrical background in the utility business, we had something called diversity. When we would build power, we did not size it for everybody turning on everything they had all at once, you know. And it's a diversity. It's taught in school.

And the propane business is very similar. You can't -- you can't build your distribution system, which is basically trucks and drivers and storage, for everybody calling all at once being out of gas. So that's where the tank monitors help. I can trickle that in. I can keep everybody full as I need to.

It's just a difficult business when you have the demand we had, and then you had supply, in my case, being cut in half or more with the refinery going down.

So trying to think of anything else I can think of. You guys got any questions for us?

SECRETARY KEOGH: Thank you so much. Appreciate you for --

HARDY THOMPSON: You're welcome.

SECRETARY KEOGH: -- being here and your candid discussion. We'll move through a few questions.

I think I will start. Just, you mentioned your strategy of monitoring tanks, and that's excellent if you have the technology to do that. I think that's great. And I assume that that communicates back to you realtime or when they're needed; is that correct? Or is that how you do it?

HARDY THOMPSON: It talks to us every morning, and then if there's an event, whether there's a tank fill or a rapid draw or if it triggers, you know, a tank level. Like, say, I want it to alarm me at 30 percent, it sends me an alarm. Yes.

SECRETARY KEOGH: We love remote sensing and technology in our world.

HARDY THOMPSON: Yes.

SECRETARY KEOGH: I appreciate that you use that as well.

Do you think any -- I think there was a

reference to early notice to customers, perhaps preseason notice. Is that of any value, or do you feel like your technology probably compensates enough for that, that you don't need it?

HARDY THOMPSON: You know, I don't -- as far as a statewide push for early notification of fills, I think it's going to be a marketer-by-marketer area basis. We do a pretty good job with social media and that type of thing to communicate with our customers. We really -- we stress that, and it's important to us.

But as far as the people that aren't our customers, you know, it's hard for me to say what would help them, except that they need to have a good relationship with their supplier and really know about their supplier.

I don't -- I don't -- you know, back when all this happened, they asked, hey, do you want us to send out a notice that says, hey, everybody conserve gas? Well, in my mind, that's going to make my customer panic and call me and say, fill my tank up.

SECRETARY KEOGH: I think that's probably --

HARDY THOMPSON: And that's -- that's what would happen.

SECRETARY KEOGH: Good point. Well, thank you. And I -- that's probably one of the concerns on the electric grid as they notice conserve. Everyone probably turned their heat up a little bit, just in case it went out, but hopefully not. I think there was good efforts by citizens across the state to try to conserve actually.

HARDY THOMPSON: Absolutely.

SECRETARY KEOGH: I think --

HARDY THOMPSON: And we did put out a Facebook push to our -- to our customers, hey, conserve gas, you know, we've got your -- we've got you covered, but you know, we can't get transport trucks down the road.

And it wasn't our trucks. We ran seven days a week, just like Ron did. But the transport trucks, you know, they were stopped so we only had what we had.

SECRETARY KEOGH: Right. And I know at my household we went the other way, trying to conserve as much as possible.

With that, I'll move on to Director Sparks to see if he has any follow-up questions.

DIRECTOR SPARKS: Again, Hardy, thank you so much for being here. Quick follow-up question on the monitors.

What percentage of the industry has those in place? Any idea other companies got those out there? And kind of a follow-up to that, is it high-dollar to install that kind of a system?

HARDY THOMPSON: Well, it's a very small fraction of tanks out there with monitors on them. And you know, I'm a small independent. I'm the owner of the company. And I feel like it's a good economical decision for me to monitor my customers, especially, you know, the higher use ones, the ones that are keep-filled.

And I think the propane business, it's so fragmented. Historically, they're just -- they drag their feet on technology. And I don't think that anybody would disagree with that, even Kevin, I'm sure. It's just hard to get a lot of people together and praise technology. Well, the way I see it, I'm going to make more money at the end of the day, keep my customers happier with tank monitoring. And I think, you know, if people would look at it differently like that, they would embrace it more.

But to answer your question, very tiny fraction of tanks out there are monitored.

DIRECTOR SPARKS: Thank you so much.

HARDY THOMPSON: You're welcome.

SECRETARY KEOGH: Director Bengal across the table from me may have a question.

DIRECTOR BENGAL: Just to follow up quickly on the monitors: Do you use the customers' internet service to connect or is it a cell phone connection at the monitor on its own?

HARDY THOMPSON: The monitors I use are dual band cellar, so they use either Verizon or AT&T systems. But they are -- they have ten-year battery and they're on cell phone.

DIRECTOR PFALSER: Do you bear the cost of them than as the supplier, or do you pass that on in the gas price?

HARDY THOMPSON: Well, I mean, we only have one way to charge anybody for anything, it's through our gas price. But I don't detail it out as an extra charge or anything --

DIRECTOR BENGAL: Okay.

HARDY THOMPSON: -- like that. That's just part of being a customer of Island Energy.

DIRECTOR BENGAL: But the cost is minimal enough, it's not that big of a deal, I assume?

HARDY THOMPSON: Well, it adds up, but it is minimal. I think it costs about -- you can average $3.00 a month per tank.

DIRECTOR BENGAL: That's good.

HARDY THOMPSON: But if you have 1,000 tanks, that adds up.

DIRECTOR BENGAL: That's all the questions I have.

SECRETARY KEOGH: Director Pfalser, do you have questions of either of our speakers?

DIRECTOR PFALSER: Hardy, you were talking about the storage and steel and you all are in a growth area over there. You -- how long has it been now since you've acquired the location in Osceola?

HARDY THOMPSON: We took over Osceola in March of 2017.

DIRECTOR PFALSER: Okay.

HARDY THOMPSON: And then as you know, just this past summer we opened up another store in Pocahontas. And thankfully we did, we were able to help a lot there, but it's a good area.

DIRECTOR PFALSER: And the steel, the steel prices, are you typically -- right now, are you purchasing new steel or are you purchasing used steel, or anywhere you can get steel?

HARDY THOMPSON: We'll buy used and we'll buy -- okay. First, we'll buy refurbs out of

Oklahoma where they've been sandblasted and everything fixed. That's our preferred way to buy domestic tanks.

We will buy used if we have to, because apparently it's hard to get domestic tanks, just like everything else. And I will buy new tanks if I have to. But my preferred is refurbished tanks out of Oklahoma.

DIRECTOR PFALSER: And what have you seen with steel prices? Kind of crazy?

HARDY THOMPSON: They've gone up. Just used tanks in one year from last summer to this summer, they've probably gone up 60 percent. And then I haven't bought a 30,000 gallon tank in a long time, but I'm sure that they are extremely expensive.

DIRECTOR PFALSER: Okay. The hours of service, was that a benefit to -- to have that waived to where you can run longer?

HARDY THOMPSON: Oh, certainly. And as far as I'm concerned, you know, the way this works is once you get behind, you're always behind.

And the hours of service, I know they've got to look at a storm or they've got to look at a weather event to decide whether they're going to do that. I'm not so sure we don't need to just have a blanket January, February hours of service lifted every winter. That way people once they're behind, they can't -- they don't have to stay behind.

DIRECTOR PFALSER: Well, and what months do you think -- if your business is 60, 70 percent domestic, then what months are you looking at to do all your business for the year? I mean, it's --

HARDY THOMPSON: Okay. Yeah. Number one month is January typically. Number two month is February. Number three month is either March or December. That's it.

DIRECTOR PFALSER: That's where you --

HARDY THOMPSON: This year -- this year it flip-flopped because February was so bad. But normally January, February and either March or December.

DIRECTOR PFALSER: So those are the months. And so the rest of the time then, we're trying to staff for months where there's no -- there's no need, but you have to have them for basically those three or four months?

HARDY THOMPSON: Well, we're in the fortunate position to where we use the rest of those months to set tanks. But we also do a significant forklift industrial service. So we stay pretty busy with that all year.

But yeah, you've got, you know, three or four months that are pretty intense and then you've got, you know, the rest of the year that slacks off quite a bit.

DIRECTOR PFALSER: I don't know what that would look like to approach a permanent hours of service for a certain period of time, but that makes sense because of the way our business, the industry does business.

HARDY THOMPSON: Well, you know, we just got through talking about how you can't prevent the -- you can't predict the weather in advance far enough to get the executive order done in time, because by the time it's done, everybody's already empty and behind.

So if you could just maybe pick December, January, and February or something like that to help get ahead of things, because, you know, there are only so many trucking companies. The pipeline, you know -- the pipeline is not predictable as far as I am concerned, which is why we were on the refinery gas. Well, I learned my lesson there too.

Any other rail facilities in Arkansas -- you know, I would like to see a rail facility somewhere in northeast Arkansas just like Ron would, but I don't know who would, you know, economically decide that, hey, that's what we're going to do.

DIRECTOR PFALSER: Right.

HARDY THOMPSON: Let's see, that's mostly the things that I wanted to talk about. But I'll be glad to answer any questions you've got. We try to stay ahead of things, but during times like that, it's really hard.

DIRECTOR PFALSER: Well, Hardy, I appreciate you, like everybody else, taking the time to be with us. It's been helpful.

SECRETARY KEOGH: And I'll just -- as I mentioned, our other folks that have testified, this is a process that this Task Force is going through. We'll be combining our notes.

And if you have any additional feedback or thoughts that you may have missed today that you think would be meaningful for us to know, this is not a final chance. You can reach back out through your association. She can provide it to Troy through our e-mail site or directly to Director Pfalser. We'll make sure that the report drafters and those that are preparing the recommendation, that we will review it together and incorporate as much as possible that

we're hearing from these hearings.
So thank you for your time today. I know that I want to give a chance back to Laneigh to make any closing comments, but -- and if anyone has a question for her. I appreciate, Laneigh, as well, your thoughts and your appreciation for that time of service.
I know the governor acted prior to the winter event, actually, because of a shortage already in place, as I understand it, in some parts of the state. So I'm not sure what occurred on the 23rd. It was referenced later, but I know that may have been --
DIRECTOR PFALSER: It was an extension.
SECRETARY KEOGH: Extension --
DIRECTOR PFALSER: The 10th was the original one and then the 23rd --
SECRETARY KEOGH: And so I know that other states, as you mentioned, we had communications, were not as comfortable with those changes. And I know it's a safety consideration for your drivers, but it's also a safety consideration for those that need gas at that time.
So with that, I'll turn it back and thank you again for your comments.

HARDY THOMPSON: I did -- I did have one more little thing.

If you can reach back out to NGL at some point, you might look at our inventory right now based on inventory last year in our area. They're 31 percent lower right now than they were at this time last year. So just something to think about for this next fall.

SECRETARY KEOGH: I think you got their attention in this room.

HARDY THOMPSON: It's true.

SECRETARY KEOGH: That's good to know. That's something we should work with the companies. And maybe, Kevin, we can work on that. That's a good way to evaluate, you know, each year to make sure that we're on forecast, or at least if we feel like there's a potential of a problem going forward.

With that, I guess, Laneigh, you want to make a comment?

LANEIGH PFALSER: Just from a national standpoint in working with colleagues in other states, just some things that I, you know, think might be necessary to be aware of.

So we have -- you have asked, like, is it industrial? Is it, you know, home-based? Like, what was the customer base? We also have a couple of other members in our association who have clients in the manufacturing industry.

I did some research during this related to a legislative issue. And so we'll be doing some more extensive research over the next year in preparation for 2023. But we have two new -- or we have one facility I'm aware of and we have just a brand-new facility that goes in that uses propane in their manufacturing process that is coded manufacturing for their kilns, to fire their kilns. They're very, very large kilns, is my understanding. And they do a large number -- amount of gallons a day.

So we also have an autogas bus. One of the school districts here in central Arkansas has bought two autogas buses. And these are -- whenever we say autogas, they're propane-type fired buses and they're not run by diesel. And the buses are not -- were not outfitted to become propane. They were originally manufactured to be propane buses. It's a clean-burning energy, and so they have headed that direction.

So when we talk about product and moveage and where the propane industry is headed, these are where we're headed. And obviously, as an advocate, I hope to expand that even further. So those are things to be made aware of in the future. That's all I've got.

SECRETARY KEOGH: I know we're talking about all kinds of new modern infrastructure and modern automobile technology as we look at our fleets. And so I suspect, especially when you're looking at the difference between -- different vehicles and buses, transports --

LANEIGH PFALSER: We're actually even at the national level, our national association is going to be starting to offer perks to our members this next year to convert their own bobtails to autogas. There will be perks involved with that so we will be utilizing the product that we sell.

SECRETARY KEOGH: All right. Thank you, again, for your time. At this point, it's -- we're about four minutes over. So thank you for your patience as we wrap this first session of the afternoon up. We'll take a break and then we'll reconvene, for those of you that might be listening in, at 2:45. So a short break, 10-minute break.

And then we have several speakers, including Enable Energy, Summit Utilities, and I believe CHS, who we asked to reschedule this afternoon due to our power glitch this morning. So we expect to hear from them beginning at 2:45. Thank you.

(Whereupon the hearing was adjourned.)

SECRETARY KEOGH: Good afternoon. Thank you for those of you that are joining us this afternoon. Today is June 2nd, 2021. While we planned to be at the Arkansas Department of Energy and Environmental Headquarters, due to actually a power outage, we shifted over to this lovely facility, the home of the Liquified Petroleum Gas Board. I like to coin it as E&E's North Little Rock East, but we're happy to join all of you here and appreciate your patience and flexibility.

I know we have a number of Zoom people this afternoon, so I think most of our in-person witnesses were handled in the previous session. So as we continue our discussions, for those of you just joining us, I am Becky Keogh. I'm Secretary of the Department of Energy and Environment. I have the pleasure of serving on this Task Force with the Secretary of Commerce, Mike Preston; Director of Oil and Gas Commission, Director Larry Bengal; and the Liquified Petroleum Gas Board Director Kevin Pfalser.

For this afternoon, Director of the AEDC

Existing Business Resources Division, Director Steve Sparks is joining us due to a conflict that Secretary Preston had this afternoon as he's presenting expansion of our technologies across our state. Hopefully, it's a proposal that could be -- help further our internet services and broadband capabilities across the state of Arkansas. So hopefully he's on that proposal.

On March 3rd, 2021, Governor Hutchinson signed Executive Order 21-05 which established the Energy Resources Planning Executive Task Force. And the purpose of the Task Force and the hearing today is to gather information as an administration from this testimony in order to better prepare our state's infrastructure in the event of another statewide emergency.

I mentioned earlier that this administration has endured three 100-year emergencies: First, a 100-year flood, global pandemic, and now 100-year ice/storm event. So we want to make sure that as we go through these events, while we can't control those occurrences, we can definitely learn from them.

And the governor is focused on after-action assessments and developing and learning best practices and learning from these events to be prepared and to enhance the certainty of our -- stability of our -- and certainty of our infrastructure to our citizens, as well as our commercial businesses.

As chair of the Task Force, I have the pleasure of calling on each of you to present today. And I will call out the name of the organization that will testify. And if you will just, however you're participating via Zoom or via in person, I guess in this case basically Zoom, I'll ask you -- once I introduce you, I'll ask you to state your name, title, and organization. This is primarily for the purpose of our recording and creating a record so that we can review it and later prepare a report for the governor that you will have a chance to review and have input to.

After -- if you would open with opening comments, that would great, or any statement that you have. We would ask you to limit that to five minutes, just out of respect for the other participants this afternoon.

After that five-minutes-or-less presentation, we'll -- I'll open the floor to the Task Force members here today to ask questions.

Again, our Task Force members have studied the testimonies that were prefiled, the question and answers that many of your organizations prefiled with us. And so hopefully, these questions will build on those or fill in any questions that we might have.

We've allotted about 15 minutes, so we don't want to tie up too much of your day. And I appreciate that you've been on hold with us this afternoon. We did, as I said, encounter some unexpected events and I think we've done well.

Andrea Hopkins, who you may be able to see or -- I don't know how many of you can see her in the room, but maybe she or Troy Deal may send you a warning that your five minutes is closing in on a time limit. So if that's the case, that's the gentle urge to try to bring your comments to close so we can move forward.

So with that, I will begin. I think our first presenter this afternoon will be Enable Midstream. So thank you for joining us, Enable. And they are a neighbor of us and I know they also encountered a power disruption today at their operations in North Little Rock.

So following Enable, I will ask Summit Utilities to speak, so that's to give you a little bit of a two-minute warning, or maybe a 20-minute warning, for those of you that will follow that.

So Enable, I will turn the attention to you at this point.

STEVEN TRAMONTE: Good afternoon, thank you. My name is Steven Tramonte. I'm the Vice President of Commercial for the Transportation and Storage segment at Enable Midstream Partners. My prepared remarks today address the operation of the two Enable pipelines that operate in the state of Arkansas and the impact the weather event in February had on those systems, as well as potential investments that could be made to the pipeline to help in future extreme weather events.

We operate two natural gas transportation pipelines in the state of Arkansas: Enable Gas Transmission, or EGT, and Enable Mississippi River Transmission, or MRT. EGT and MRT are interstate pipelines subject to the jurisdiction of the Federal Energy Regulatory Commission.

EGT and MRT are exclusively providers of transportation services, meaning they receive gas from or for the account of their shippers, sometimes store that gas for a period of time, and redeliver that gas to those shippers at various delivery points located on the respective pipeline systems.

In regards to our preparation for the weather event, Enable has put in place plans that include having personnel on-site around the clock at key facilities such as compressor stations and storage fields to maintain reliability.

Our field personnel also tests backup generation to ensure that any interruption in power delivery would not impair the operation of equipment.

Other preparations prior to and throughout the weather event included monitoring weather forecasts to evaluate the potential supply loss anticipated from wellhead freeze-offs, as well as to forecast the increased demand on the pipeline system due to the dropping temperatures.

On the coldest day in Arkansas, EGT experienced a loss of almost 50 percent of supply from levels flowing prior to the severe weather. And during the same period, demand for natural gas on EGT increased over 45 percent from February 1 levels.

The combination of decreasing supply, increasing demand, and having both of those events occur an extended period of time can cause severe operational issues on the pipeline. So in preparation for the coldest days of the event, both

EGT and MRT issued operational flow orders, or OFOs, to provide guidance to customers on the operating requirement needed to ensure the reliability and integrity to the systems.

As the event unfolded, EGT began to experience a sharp decline in actual supply entering the system. This was a very fluid environment where producers and gathering companies were battling to bring wells back online as others were freezing up.

During this time frame, we had customers taking more gas off the pipeline than they were bringing onto the pipeline, which was creating short imbalances. These short imbalances over time will reduce pressure across the system and will limit the pipeline's ability to run necessary compression and meet customers' pressure requirements.

It's also important to note that the volume of gas a customer is entitled to move on the pipeline is governed by the level of service they have contracted for. And some customers, during this period, exceeded those contractual rights. This is an indication that some customers did not hold sufficient capacity or space on the pipeline to meet their peak needs.

As system conditions continued to

deteriorate and pipeline pressures continued to fall, EGT continually reminded customers to remain in balance and notified them that EGT will prioritize loads serving human needs.

Both EGT and MRT have provisions in their respective tariffs that allow the pipelines in certain circumstances to prioritize human needs customers above all other customers, regardless of the level and type of service contracted for.

Fortunately, we did not have to enact the prioritization on the basis of human needs, but the preparation for that prioritization did cause many customers to cut back loads to help the system.

One additional note, our storage assets performed well during the weather event and provided a critical role in supplementing the supply loss due to freeze-offs.

Since the weather event, EGT has been exploring options to increase customer access to additional sources of supply. Currently, the EGT system is designed primarily to bring gas from production areas in the northern and western portions of the system to customers and markets in the eastern and southern position of the system.

Supply in Arkansas and Oklahoma will

continue to be a valuable source of supply for EGT, but the recent weather events highlighted a vulnerability to extreme temperatures. And EGT's plan to create additional access to southern supply basins and additional storage assets will complement the Arkansas and Oklahoma supply.

EGT will need to install additional facilities to allow customers to access supplies from areas like the Perryville hub and other liquid supply areas in the south, potentially including compression and pipeline looping.

In fact, just yesterday, EGT announced an open season, soliciting interest in a project we are calling the Supply Diversity Project. EGT will need its customers to support that investment with contracts for transportation service and to ensure their contractual commitments meet their peak load requirement and they have access to flow and supply in the next extreme weather event.

In conclusion, I would like to commend our field and operational personnel that braved extreme weather and dangerous conditions to ensure the integrity and reliability of our systems. These men and women were the main reason we were able to deliver every molecule we received throughout the weather event.

That concludes my prepared remarks. I'd be happy to address any questions you may have. Thank you.

SECRETARY KEOGH: Thank you so much, again, for your presentation, your prepared remarks. And thanks to your able staff and their willingness to, as you said, brave some very unusual conditions to make sure that Arkansans were equipped with the gas they desperately needed in some cases. So appreciate that.

Want to focus a couple of questions and then I'll pass onto the other members of the Task Force. One of the questions that we brought up yesterday with our natural gas supplier companies in Arkansas, and producers, and some of even the utility group, we talked about notification to our customers when gas might be short or subject to curtailment.

And I know that the governor received a few calls. I obviously received a few calls. I know Director Sparks mentioned a number of calls around industrial customers on the natural gas side.

So can you speak to what you've learned through that and where we might do better in terms of making sure that those customers, one, are educated to make sure they have the right agreements in place; but secondly, that if there is an effort initiated by the supplier or the pipeline company, whoever is the distributor, that that customer be notified that -- that the -- you know, someone's about to show up at their gate, if you will, to make that curtailment happen?

So can you speak -- I don't know if y'all are involved in that process, but can you speak to your involvement in that?

STEVEN TRAMONTE: So recognizing, you know, very early that we as the interstate pipeline have a little bit broader view of the potential supply impacts from cold weather, and we certainly have seen events like the temperatures we've seen, but perhaps not the duration.

So very early on, we started to communicate the importance of our customers remaining in balance and making sure that their physical supply coming in was matching up with their physical deliveries. And that continued throughout the event.

I will say, though, that from the interstate standpoint, this -- the duration of this was -- and the extreme temperatures combined, caused us to have to enact the prioritization of human needs in ways that we had never done before, and we had never experienced that.

So our communication to our customers regarding human needs was for them to have to submit an affidavit justifying, you know, or attesting to the fact that they are, indeed, serving human needs and what volumes they required from that.

So that had to deal with -- and these are all -- it's all prescribed by our tariff. That pertained to not only utility customers, but also industrial customers to the extent that service was needed to avoid catastrophic damage to their equipment.

So we enacted that. And frankly, that's a -- that's a process that we had never been -- done before. So certainly a lot of learning on our part about how to go through that process, a lot more knowledge about what it takes to actually get those affidavits done, especially during the middle of a -- during a weather event.

And probably would try to be a little bit more proactive next time on thinking about the -- when we see the duration of this being so long, perhaps getting ahead of some of those human needs affidavits prior to an event of this -- of this duration.

SECRETARY KEOGH: Thank you. And I guess the following question, we also heard from the electric utility side and the gas side as well, that certain compressor stations may have been subject to power loss as well, which might have disrupted additional ability to keep pressure on the gas lines.

Did y'all experience that yourselves? Or do you have backup power systems on your compressor delivery systems that, in the event natural gas became short, you could continue to deliver gas or electricity?

STEVEN TRAMONTE: A number of our -- on the pipeline, a number of our compressor stations do have backup power.

EGT did not experience any power interruptions that impacted, you know, our compression. Our biggest issue from an operational standpoint were customers taking more gas off the system than they're having supply come on. And what happens in that case, as I mentioned in my prepared remarks, is your pressures start to drop along the pipeline. And that impacts the ability to run compression.

Luckily, we were able to centralize our

compression along our system to then make sure we could deliver every molecule that we received.

SECRETARY KEOGH: Okay. And that may be that that was more at the wellhead compressors, or it may be those compressors -- I know we were listening to some stories from Texas where I believe a number of their compressor stations are tied into the electric grid, as opposed to having, you know -- many of the Arkansas ones I know are more remote, and therefore, they are set up with backup generators.

Anyway, appreciate that. I'm going to turn now to Director Sparks to see if he has any additional follow-up. Thank you.

DIRECTOR PFALSER: Great. Thank you, Steven. Quick question with regard to your affidavit process.

You mentioned that you were having to do things that you've never done before, lessons learned on that, timing, process. What have you guys learned that we might benefit from as a Task Force to look at that on a larger scale?

STEVEN TRAMONTE: Well, one thing we learned was, you know, the supply on EGT, we could have brought in a lot more supply from the south if we had that physical capability.

And so the gas pricing differential was quite dramatic between our northern part and southern part because most of our supply is out in western Oklahoma and throughout Oklahoma and into northern Arkansas. That saw the largest impact to wellhead freeze-offs.

So one of the things that we're looking at, and I mentioned it briefly in my comments, were projects to have increased supply availability throughout the -- throughout northern Arkansas, is the primary consideration, of being able to get that gas from south to north. That would have provided access to a lot more supply and actually a lot more storage assets that are primarily located in kind of north Louisiana.

DIRECTOR SPARKS: Okay. Thank you. With regard to the affidavit process, what have you found the best way to communicate and get that information back to you to make those calls?

STEVEN TRAMONTE: So I think the largest part there is helping everybody understand that the the tariff does allow for a prioritization based upon human needs. And now that we've gone through that process and having familiarized people with the forms that they'll have to provide, perhaps taking a more proactive step.

And this may not just be for cold weather events. It may just be prior to the winter, is helping us understand prior to each winter what, indeed, those loads are. And that would prepare us for these events and not having to go out and get affidavits during the event.

DIRECTOR SPARKS: Thank you.

SECRETARY KEOGH: All right. And to the -- to your affidavits, I'll just comment, I know we've heard -- and our recommendations may focus on some -- in addition to human needs, I think there is some provision for protection of, as you said, commercial or industrial equipment that might undergo significant damage, having a minimum amount of gas, not necessarily production level, but minimum of gas to maintain that heat.

Or even we heard poultry operations, to maintain loss of significant livestock or, in that case, poultry. So those are some things that I think all play into that affidavit process.

But we've heard some recommendations in that regard, so we're happy to share those with you as well as we look forward to that.

With that, I'm going to turn over to

Director Bengal, if you want to address questions.

DIRECTOR BENGAL: Thank you for coming. Just a couple questions.

The Enable pipeline, it's a east/west along the Arkansas river route, is it not?

STEVEN TRAMONTE: We do move gas primarily east to west, and then really down south into north Louisiana.

DIRECTOR BENGAL: So from the standpoint of the Arkoma basin gas in western Arkansas, does that area contribute much to your supply in your pipeline?

STEVEN TRAMONTE: It contributes -- it is not the majority of supply, but it does -- it does feed into our system.

DIRECTOR BENGAL: So how much of your system that you bring into the state stays in the state, versus moves on east?

STEVEN TRAMONTE: So those numbers, I'm sorry, I'd have to get, you know, more information to you offline about those exact numbers. But the percentage wise, the gas that's coming in the Arkoma would probably be a much smaller percentage, as opposed to the volume that we're receiving in Oklahoma that moves into Arkansas to supply northern Arkansas.

DIRECTOR BENGAL: And I think you have a line that takes a large portion of the Fayetteville shale gas on east?

STEVEN TRAMONTE: So our particular system, EGT, receives very little volume from the Fayetteville shale. There are competing pipelines that move the vast majority of that volume further east.

DIRECTOR BENGAL: Okay. That's all.

SECRETARY KEOGH: All right. Director Pfalser, this is your chance to ask.

DIRECTOR PFALSER: Thank you. Like everybody else, I appreciate you taking the time to be with us today.

Storage, this is something that I didn't realize happened with natural gas, and you had mentioned that. Where is your storage at?

STEVEN TRAMONTE: Yes, sir. So we have storage facilities in Oklahoma and north Louisiana on our EGT system.

DIRECTOR PFALSER: Okay. And that is a geological, is what allows for the storage? That has to be in place before it can be utilized for natural gas?

STEVEN TRAMONTE: That's correct. So our

storage facilities consist of reservoir storage facilities on EGT. There are other storage facilities that are salt caverns that are located -- excuse me, in north Louisiana that we connect to but aren't owned by EGT.

DIRECTOR PFALSER: Okay. All right. That was all that I had. Thank you.

SECRETARY KEOGH: All right. Thank you for your time today. Appreciate the information. If there's any information that you think may be -- comes to your attention in the upcoming month or so that you think may be beneficial as we prepare our recommendations -- we hope to pull that together in a draft report, share it back. But also we'll ultimately be briefing the governor with those recommendations.

So appreciate any input as you -- as you go through your reviews, as well as anything else you have to offer, we appreciate that. So feel free to reach out through our communications team. We've set up a specific e-mail site. Troy Deal can help you with that if there's something -- if you have a report that y'all put together or any documentation that would be helpful to us that you're willing, you know -- it's open to the public for sharing.

So thank you, again, for being present today though.

STEVEN TRAMONTE: Thank you for your time.

SECRETARY KEOGH: With that, I'll shift gears. I will ask, I guess, the next organization will be Summit Utilities, who is also joining via Zoom, I believe. We'll ask for their organizational representatives to open with their name, title, and the name of your organization.

WALT CARTER: Good afternoon. Thank you for hosting us today to speak about the winter storm events. I'm Walt Carter. I'm the manager of Gas Supply and Contracts for Arkansas Oklahoma Gas, or AOG. I'm joined today by our Vice President of Sustainability and Corporate Affairs, Lizzy Reinholt, and our Director of Operations in Arkansas and Oklahoma, Tony Parker, and also our Chief Customer Officer, Fred Kirkwood.

Perhaps I can start out by giving you some background on AOG and then we'll speak a little bit about the events of February, if that's okay.

SECRETARY KEOGH: Great. Thank you.

WALT CARTER: AOG is a natural gas distribution company that serves the Fort Smith, Van Buren, and surrounding areas. We have about 60,000 customers in total, majority of which reside in western Arkansas. As an energy provider to homes, businesses, and industry, we provide safe and reliable and affordable natural gas to our customers.

During Winter Storm Uri, our system was challenged due to upstream gas supply constraints that were beyond our control, but we were able to successfully preserve gas supply for our human needs and our residential customers throughout the storm thanks to a combination of our gas supply plan, enhanced communications with customers, and successful execution of our curtailment plans.

As a background, AOG always takes weather events into consideration as part of our gas supply planning. Our gas distribution plan uses historic weather data to project daily and monthly demands under various weather scenarios. It also uses historic weather events and market response to monitor our hourly and daily requirements under extreme weather conditions. The models are comparable to the planning models of other LDCs across the country, including Black Hills.

AOG's supply strategy includes diversification of its supply portfolio. 20 percent of our design-day needs supplied from gas wells in the Arkoma basin, and 40 percent from each of our two upstream pipelines, Enable and Ozark. All of our contracts are confirm service.

AOG began preparing for Winter Storm Uri February the 10th by reviewing our system operating conditions, our demand forecasts, and our active supply agreements, and also by communicating frequently with our gas suppliers and upstream pipelines about our upcoming needs.

During the course of the following week, historic weather conditions throughout the region resulted in natural gas supply shortages and extreme index pricing. As gas would show up in our upstream pipelines, our system supply nominations were cut.

At that point, we were required to curtail our interruptible and commercial customers in order to preserve supply for our residential heat load customers. We also issued customer communications asking our customers to conserve usage where they could.

Thanks to these curtailments and the customers reducing their gas usage, we were able to keep homes warm and maintain service to human needs customers, despite significant gas supply issues beyond our control.

Thankfully, we were (disruption in audio) before any further curtailments were necessary and we were soon able to restore service to our all customers.

(Disruption in audio) due to our staff, both in the field and in the office. They worked incredibly hard to keep everything going that week.

While our 2021 gas supply plan forecasted a maximum daily requirement of just over 100,000 MMBTU, as a result of the extreme demand we experienced in February, our new design-day increased to almost 106,000 MMBTU, or almost 6 percent.

AOG is continuing to evaluate our options, to diversify our supply portfolio even further in order to ensure reliability of service to our customers. We look forward to speaking with you more today and I'm happy to answer any questions you may have about our response to the winter storm. Thank you.

SECRETARY KEOGH: Thank you. Do appreciate the others for participating as well. Is there any statements or comments that they would like to make at this time?

LIZZY REINHOLT: We're just here based on questions so that we made sure to have the appropriate folks in the room.

SECRETARY KEOGH: Thank you for being present and thank you for all your efforts in Arkansas. Thank you for your partnership.

I know -- I guess I would raise the question that I raised to the previous speakers around notification, just in terms of your approach to notifications, particularly with your commercial customers as those were the ones that seemed to be a bit on the surprise element, I think.

So I guess it was just -- and I'm not sure we heard from your direct customer, so I'm not -- this is not a comment about your operation at all. But just anything that you found as a helpful lesson learned that we can put in our recommendations going forward to all our natural gas providers in the state and our commercial organizations, as far as preparing themselves better for a potential curtailment in the future?

I don't know who to turn back to, but I guess --

LIZZY REINHOLT: Fred, do you want me to start that or do you want -- do you want to speak to particularly industrial and large commercial and I can speak a little bit to the small commercial and the residential, if needed?

FRANK KIRKWOOD: Yes. Let me speak to the industrial/commercial. And first of all, this was a unique experience for us as a company, as well as those industrial customers.

I want to start by saying that one thing that first comes to mind in addition to notification is preparation. And a lot of our industrial customers are so used to having a reliable natural gas, that they didn't have any backup sources. So it made it difficult then to even respond when we reached out to them.

But from a notification process, lessons learned in this instance, is that we should -- we as a company and as the industrial customers we serve, we had a lot of communications around updating our customer profiles to make sure that we have current information on who the direct contacts are. In many times, we reached out to folks and we had to locate folks in other states and jurisdictions to get to the key communicators to actually not only make the decision, but also implement the curtailment that was needed.

So I think the most -- best lesson learned is around just having a continuous process to update customer profiles of information. Because in many of these corporations, there's a person who makes the decision. There are people who actually run the equipment, and people that will follow through with their employees. So just having that information updated, I think, is the most helpful tool that we learned in this process.

SECRETARY KEOGH: Thank you. You had additional comments about smaller customers, I believe or --

LIZZY REINHOLT: I think it's worth noting, one thing that we did do in this instance is we did curtail the large industrial, you know, the transport customers, and those were shut off. For our small commercial, what we did is, it was a tremendous amount of -- you know, it was a number of different customers. We weren't able to call each and every one of them one on one like Fred's team did with the large commercial and transport customers.

But we did not physically shut them off. We told them they were being curtailed, but they were able to turn their thermostats down and, you know -- and we asked them to do that.

You know, obviously one of the things that was really bad about this situation was the little notice we had around our supply shortages. We had nominated the proper amount of gas, but we didn't necessarily have a huge heads-up as to when we were going to lose that supply which limited the window of time we had to communicate with the customers.

Though we had been communicating with customers since February 10th about how to conserve, about winter storm issues, really the turnaround, right -- no one thinks they're actually going to lose their gas service. And the turnaround in being able to communicate with them, that short window really made it difficult.

One thing we did during this storm that we're definitely going to be using moving forward was we set up a text message program. We hadn't used text messaging prior to the Winter Storm Uri. And I'll tell you, that program was a real lifesaver for us in communicating with residential customers about conserving, but also with commercial customers when it came to the overall curtailment.

And Fred's team did a great job too of also keeping customer service on longer hours to answer questions because we knew customers were going to have them and curtailment came near the end of the day.

So we did everything we could to really make sure we were still there for our customers, despite the lack of reliability, and answer their questions. But given that this was the first time that this had ever happened and now, it gives us time to educate folks about exactly what happened and why those curtailments happened.

SECRETARY KEOGH: Thank you. I guess I know that the supply diminished quickly as you mentioned. So hopefully, I guess the other conversation we heard was weatherization yesterday.

So is there any comments that you have around what you may do on your system in response to assuring, you know, if you had any issues with weatherization in terms -- or if it was more on the wellhead issues that resulted in the shortfalls to you?

So is there's any comments there that you'd like to make or recommendations?

WALT CARTER: So the assumption is, you're talking about our system, our ability to deliver the gas that was actually presented to us --

SECRETARY KEOGH: Right. I understand the wellhead, many of those froze, and you can't control that. But is there anything that you encountered in your system that is a recommendation that -- or a lesson learned or an investment that you'll be making in the future?

WALT CARTER: The AOG system functioned very well during the cold weather that we had, what you would expect. We had lower pressures at some of the dead-end feeds. We had enough gas on the mains that we were able to maintain those feeds. We didn't lose any customers because of freeze-offs or equipment issues.

So it did -- it was -- I wouldn't say flawless, but it performed very well. We had a lot of people in the field paying attention, bypassing where necessary to help save the load and the pressures.

But as far as system improvements, you know, short of storage, I think right now we're looking at supply. Supply is just -- was our downfall and supply is the answer.

SECRETARY KEOGH: Okay. Well, I'll turn over to the other Task Force members. They may have questions specific to storage and supply. So with that, I'll turn over to Director Sparks to see if he has any questions about your comments or any follow-up.

DIRECTOR SPARKS: Thank you very much. I think actually you've covered all the questions that I had. I appreciate that information. Thank you.

SECRETARY KEOGH: I'll shift over to Director Bengal from our Oil and Gas Commission.

DIRECTOR BENGAL: Thank you for being here. You know, it's good to know that every time I Google AOGC if I want to find our webpage for the Oil and Gas Commission, AOG comes up first. I'm always going to scroll through and down to AOGC. You're first on that Google search.

The question I had: Did you experience -- did you have to purchase any of that higher-cost gas to augment your system? Or you just stayed with your contracted amounts that you had that were delivered to you?

WALT CARTER: So similar to the other Arkansas lessees, we have all of our gas contracted for in one annual process. And we have these packages of reserve gas to call on as we go throughout the winter. We experienced shortages on several of those packages of gas, required us to -- we always try to nominate the gas in order of economic priority, right. So we try to get the lower cost gas in first.

And unfortunately due to supply cuts, we had to go into those higher-price packages and the -- that were tied to the index pricing that really went crazy. So we did shift our gas packages out of necessity, but we didn't go outside of the contracts that we had, the winter contracts we had in place and had to go out in the spot market. Unfortunately, nobody had gas to sell.

DIRECTOR BENGAL: Sounds like the customers that may have experienced higher prices during that time, was it -- were you able to allocate that to industrial, or did residential customers also have to experience some of that?

WALT CARTER: It's going to be primarily on the residential customers, residential and small commercial. The industrial customers, of course, were buying their gas from third-party marketers or suppliers. We didn't -- weren't attributing any of the kind of high price gas demand to those customers.

DIRECTOR BENGAL: That's all I have.

SECRETARY KEOGH: Director Pfalser, do you have follow-up?

DIRECTOR PFALSER: Yes. Again, thank you all for taking the time to be with us today. Where is your customer base located within the state of

Arkansas?

WALT CARTER: We have five counties in western Arkansas, primarily Sebastian County, and Crawford, Scott -- somebody could help me out.

TONY PARKER: Franklin and Logan.

DIRECTOR PFALSER: Okay. And Secretary Keogh was -- talked about this just briefly, the notification and communication. And y'all said that you had fairly short notice when supply was dropping. Who would that come from to you? Who would be the one to communicate that to you?

WALT CARTER: So there's three parties in this relationship. It's the distribution companies communicating with its gas suppliers who are putting the commodity in the pipe in the upstream pipeline and the interstate pipeline system.

And so we would, during the event, we were watching our -- we go in and we put our supply nominations into the pipeline and we say, this is how much gas we're going to put in your pipe for delivery to our system.

But then as the gas didn't produce into the pipe, then we were getting notified by the pipelines that, hey, we're going to have to reduce or cut your nominations down to match what's actually coming into the pipe for you.

So those communications were primarily coming to us from the pipelines. And then we were calling the suppliers and asking if they could do anything, or what they could do to help us get more gas on.

DIRECTOR PFALSER: Okay. So it wasn't necessarily coming from the producers or who you're buying the gas from? It was coming from the transporters, the pipeline, as they were seeing pressures drop or something like that?

WALT CARTER: Yes. Exactly. Yeah. They were -- they were notifying us that, hey, we're losing pressure on our system. You guys are taking off more gas than you're -- you put into the pipe on your behalf. So then we would communicate with the producers and suppliers at that point.

DIRECTOR PFALSER: I gotcha. Okay. That's all I had. Thank you.

SECRETARY KEOGH: I, again, thank you for being present. I think Director Bengal mentioned one of the other notification questions that, I think, typically, there's a human needs, like you said, affidavits and notifications when there's a curtailment or lack of supply in this case.

But I know that a number of customers, at least on the natural gas side, seemed to have been not -- either caught off guard or not monitoring the fact that the costs were increasing significantly so maybe ended up with a higher level. And some have indicated they might have chosen to do a little more voluntary cutback had they known the cost.

Is there anything that you think on the natural gas -- I mean, the electric grid has a protocol for that through a, you know, interruptible tariff, the process where someone on the front end can say, hey, if the prices get over this amount, you know, slow me down or cut me off, whatever.

Is there a process that natural gas can use? Is that even practical in the natural gas world, that we might look at going forward?

WALT CARTER: Possibly so. Yes. One distinction, though, is that the large industrial plants are those customers buying their gas from a third party. They're not buying utility's gas. We're just distributors. So I know a lot of them worked with their marketers to buy the gas and put the gas in the pipe on their behalf.

On issues like cost, and sometimes it is more economical for them to shut down or stop production rather than to run a high-cost situation. So that's possibly -- I think that would be a process that they work out with their -- with their gas supplier.

SECRETARY KEOGH: All right. Thank you. That's an excellent answer. Appreciate your time today, all of you. Appreciate your work in Arkansas, your support to our citizens and our important commercial customers and utility. So thanks for that. And we will wrap up our conversation with you today.

Again, as I said earlier, if there's any information or lessons learned that you have -- are comfortable sharing with us that we can incorporate, we'd love to share that with the governor as well. So feel free to reach back out to us through the contact that you have and we'll make sure that we take a look at that as we put together this draft report.

That report should be available for -- we'd like to ask folks that participated in this to look at it sometime in early August. Hopefully, it will give us time to turn it around according to the deadline expressed by the governor in his executive order. So perhaps a little bit earlier, but I don't know. I won't make a commitment because I know my staff is working hard and has to interview all four of us and has to do all kinds of things to get that report compiled.

With that, I will close this conversation and move on to our final group today, which is CHS. I forgot to do the warning, but I believe we've got someone on the phone or in the Zoom format to join us. And again, thank you, again, to AOG for their work.

CHS, I know that we have really asked you to make adjustments today, and that is greatly appreciated as we had to --

MARK PORTH: Glad to do it.

SECRETARY KEOGH: -- change our schedule and make some changes, but thank you for joining us. And I will just turn it over to you now to introduce yourself and your organization and provide opening comment.

MARK PORTH: Thank you very much. Really a privilege to be able to speak with you guys today. And I applaud you guys for being progressive to try to figure out how to help the energy in the state of Arkansas to be better.

I apologize, I may have some internet

issues as you guys may have also, so if it's okay, I may drop my video. That way my audio will work better. Is that all right?

SECRETARY KEOGH: That's fine.

MARK PORTH: Okay. Very good. My name is Mark Porth. I do work for CHS. CHS is one of the largest wholesalers of propane in the country. We do cover propane from the east to west coast, from the north to the south.

I am currently charged with the -- with the state of Missouri, Kansas, Arkansas, Oklahoma, Texas, and a part of New Mexico. So I cover a pretty good expanse of territory and see a lot of different supply opportunities and sources as the winters roll through. And am very excited about, you know, what can happen in Arkansas.

From the propane side, Arkansas is a little bit of an anomaly that the majority of its fuel comes in from outside of the state. You have one central pipeline that runs up through the middle of the state, and then the majority of it comes in from all sides. And so -- and that's where we, CHS, step in and supply a large percentage of that fuel that will come out of Missouri. That fuel will come out of Illinois. That fuel will come out of Kansas. That fuel will come out of Oklahoma. That fuel will come out of Mississippi into the state of Arkansas.

And so all of that fuel must be trucked. And so during the summer months, there is sufficient fuel in through the local infrastructure to be able to manage the demands and needs of the state. But as soon as it starts to cool off, that changes to where we are going to be much heavily -- more heavily reliant upon our transportation carriers to be able to bring our fuel into the state of Arkansas.

And I think that's where we need to look and -- as a piece of an answer, how to be progressive and how to help the state of Arkansas supply itself with propane.

We, CHS, really none of our customers had an extended outage or any outage at all because most of them we had worked through and had a plan prepared and developed. Because winter shows up every winter, you know. It's going to get cold sometime, right.

And so with a plan and preparation, whether that's an alliance with carriers or our supply locations or just planning and preparing and getting fuel into the right locations, most of our customers did not have issues.

Did they short fill? Did they allocate

themselves? Possibly. And those could happen for multiple different reasons.

But you know, for the most part, it was a tough winter, no doubt about it, and I'm glad we're on the other side of it. And again, I applaud you guys for being progressive in trying to figure out how we can make this better.

And so with that I'll stop, and ask some -- stand for questions. Sure.

SECRETARY KEOGH: All right. Well, thank you, again, for those comments and your perspective. If you could kind of describe -- you provide -- tell me a little bit about your footprint in Arkansas and how -- what exactly your core business is in Arkansas.

MARK PORTH: You bet. I would say the majority of our fuel that we provided into the state of Arkansas is in the northern half, North Little Rock and north. From east to west North Little Rock and north is where the majority of our fuel is -- is consumed. And so -- and again, that fuel can come in from Oklahoma.

We have refineries that we manage the offtake of in Oklahoma. We have refineries in Kansas, multiples there, where we can bring fuel into the state that typically, always does every year, comes into Arkansas from Kansas. Missouri, whether that's off the Enterprise line through central Missouri coming a long way down into Arkansas, or it can also be out of the Illinois refineries right there on the border of Missouri and Illinois. That fuel can come south into Arkansas. So the majority of our fuel is coming from the north into northern Arkansas.

SECRETARY KEOGH: Okay.

MARK PORTH: Did that answer your question?

SECRETARY KEOGH: It did. Thank you so much.

MARK PORTH: You bet.

SECRETARY KEOGH: I would assume your customers are both residential and industrial?

MARK PORTH: So we are -- right. We would provide to the retailer in the area, and then they would, in turn, deliver by bobtail to grandma's 500 or 1,000 gallon tank or to the commercial business that is consuming propane. So we are a wholesaler only and do not supply to the retail level.

SECRETARY KEOGH: Okay. We've heard an early testimony that we may have a shortage in carriers. Does that affect you or is that more on the retailer side?

MARK PORTH: It definitely does. It definitely does. Again, the majority of the fuel in the wintertime is coming from outside of the state of Arkansas. Carriers are the hugest -- are a huge piece of what we do.

And the hours of service is something that -- I don't know if you heard that, those words yet, to where they limit the amount of hours that a carrier can run. And typically during the summer months, those hours of service are perfectly adequate for the carriers to be able to do their business.

But as soon as they are having to go from, let's say, West Memphis, Arkansas to Mississippi to Petal, Mississippi or Hattiesburg, they just tripled their drive time. Therefore, they're running out of hours. So a truck that normally could make that run in a day is now taking two days to make that travel. So therefore, we've cut our trucking fleet in half.

So I think being progressive on getting hours of service to where the truckers can run further on -- before they hours-out, and doing that earlier before we get behind would be a great benefit to my customers.

SECRETARY KEOGH: Thank you. And I know

the governor, at the request of Director Pfalser and through me, you know, through the Secretary, we -- we pursued that option. This time it was just a few days before the storm, I guess, recognizing that we already had a shortfall. So unfortunately, the storm caught up quickly to us and was extreme duration, so --

MARK PORTH: By the time the storm hit, we were already behind.

SECRETARY KEOGH: Right. And I know that --

MARK PORTH: For storage, customers, they have 18 to 30 or 60,000 or more gallons of storage, but they're already deep into using that storage without the backfill of the new trucks coming in to fill that storage back up.

SECRETARY KEOGH: And that may be we need to look at that window being opened up earlier and then --

MARK PORTH: You bet.

SECRETARY KEOGH: -- shut off maybe a little bit sooner --

MARK PORTH: Yes.

SECRETARY KEOGH: We can talk about that in our recommendation.

MARK PORTH: Gotcha.

SECRETARY KEOGH: I think --

MARK PORTH: That would be a huge benefit, is if the carriers -- if, once they have to start going further, if we could help them to be able to run that -- and they're still in their standard day, they're able to run a lot farther and be able to get back to their customers.

It's a three-legged stool, without a doubt. You've got to have a carrier. You've got to have a supply location. And you've got to have somebody who owns that supply. And that's that three-legged stool who then delivers to the consumer or to the retailer.

And you've got incredible retailers who genuinely care about their customers all across the state. And those guys and their desire to work hard and keep everybody warm is very, very real.

And so the more that we can help them keep in fuel -- because the fuel is there. It's not a supply issue. It's a distribution issue. We've got the gas, we just can't get it to the right spot in the right time, if that makes sense.

SECRETARY KEOGH: That's good to know, even during an extreme weather event. Unfortunately, that was not the case with natural gas during the event.

So appreciate that and some of the challenges of distribution, besides road conditions. And I understand storage could be a solution too, but very costly.

So with that I'm going to turn that over to Director Sparks and others to pursue any of those lines of questioning with you. So with that, Director Sparks, do you have questions?

DIRECTOR SPARKS: Thank you so much. Mark, again, thanks for joining us.

Quick question follow-up on your distribution system. We've heard from other facilities that truck drivers were an issue. Were you guy experiencing things like that? How can we help?

MARK PORTH: Drivers are an issue throughout a lot of industries, whether it's the propane industry or just simply moving XYZ widgets from one location to the other. Carrier drivers are a big deal. Especially (disruption in audio) --

SECRETARY KEOGH: He froze up. May have to go off.

DIRECTOR PFALSER: Hey Mark, if you can hear us, you have frozen. So we did not catch that last bit because maybe your video was taking up some bandwidth.

SECRETARY KEOGH: There you go.

MARK PORTH: All right. How is that? Am I any better?

SECRETARY KEOGH: Sort of.

MARK PORTH: Am I back?

DIRECTOR PFALSER: You are.

MARK PORTH: Okay. Very good. Sorry about that. Your internet issues are my internet issues or something like that today, right.

So yeah. The National Propane Gas Association, which is our national organization that oversees all of the propane marketers in the country, is desperately looking for answers to the carrier or driver shortage, trying to find younger -- you know, the -- quite frankly, we're all getting a little old, you know. When I started I had a whole lot of hair and a dark beard, right.

And but through the times trying to find younger people who are willing to invest into a career of driving HAZMAT vehicles is a challenge. So yes, carrier drivers are an issue that anything the state of Arkansas could do -- and I don't have an answer for that honestly, sir. I wish I did. Because that would be an answer that a lot of people are looking for.

You know, but helping with trade schools and encouraging -- and again, it's just not HAZMAT drivers. It's any driver of any kind of a larger vehicle that requires a CDL is a tough thing to get. And then you throw the extra complication of HAZMAT on top of that, whether it's a bobtail driver that the retailer must have to be able to run that smaller model to be able to deliver his fuel to the country, or if it's the transport driver who is bringing the larger 95,000 gallons to them from various locations.

DIRECTOR SPARKS: Thank you.

MARK PORTH: Excellent question. But man, what a big -- what a big hole.

DIRECTOR SPARKS: Thank you, sir. One quick follow-up on that, if you find drivers and can get them hired, how is the retention issue with that? Are you able to retain them if you find them?

MARK PORTH: For the most part, yes, because they pay them well.

DIRECTOR SPARKS: Okay.

MARK PORTH: Because they know the value of that driver. They know that that guy is worth, you know, more than -- especially a HAZMAT driver, is worth more than, you know, not that more than another employee, but they're very valuable, I guess, is the best way to say. I don't want to shoehorn myself into a corner.

DIRECTOR SPARKS: Yeah.

MARK PORTH: But they're a valuable employee.

DIRECTOR SPARKS: Okay. Thank you.

MARK PORTH: Yeah. And I'm sure that you would've had carriers -- I would hope that you have some carriers that you have been able to ask these questions to. Director Pfalser probably has had those people in here and, hopefully, those guys are able to speak to that in a better manner than I am.

Transportation is not my stronghold, but I have great relationships with my carriers that I work with because I know how valuable they are.

DIRECTOR SPARKS: Thank you, sir.

MARK PORTH: Yeah. You bet.

SECRETARY KEOGH: Again, I'll turn to Director Bengal to see if he has any follow-up questions.

DIRECTOR BENGAL: Thank you, Mark. You said you were a wholesaler?

MARK PORTH: Yes.

DIRECTOR BENGAL: Are you operating what we term a terminal or are you sort of a -- something different?

MARK PORTH: So we would operate and bring fuel in to the state of Arkansas through probably ten different locations possibly. So we are working through a terminal, yes. And those terminals would either be pipeline connected or would have storage associated with them to where they're holding excess capacity on-site.

DIRECTOR BENGAL: So when you bring that gas from those sources or terminals, what does your facility consist of?

MARK PORTH: My facility, you know, would consist of the -- of putting the two together, of being able to have the supply where we make commitments at storage and have supply positions and prepared for a transport carrier to come and pick that fuel up and deliver to the customer, to my customer.

DIRECTOR BENGAL: So you don't necessarily manage a storage facility where you bring gas into it and retailers come and get it?

MARK PORTH: We do, but that's not solely what we do. Because we go to so many other locations to bring -- be able to -- we have -- yes. We have that storage facility, plus we have a lot of other supply sources where we are able to buy through.

DIRECTOR BENGAL: Okay. Because one of the things we've looked at and talked about is the lack of, I guess, a terminal or at least a wholesale point in western Arkansas.

MARK PORTH: Sure.

DIRECTOR BENGAL: Is what you do transferrable to that part of the state, or not?

MARK PORTH: You can do that through many different ways. You can invest in a rail car facility. That will bring fuel in. And we have looked at those opportunities, but based on economics, they don't work eight or nine months out of the year. And it's very difficult to invest those kinds of dollars for a three -- or 90-day facility.

Because of the other -- you know, the other locations that are around you must move their fuel also, whether it's a refinery that has limited storage capacity that they're going to sell their fuel, but they're also one-to-one. For every load they make in the summer, they only make one in the winter.

DIRECTOR BENGAL: So the --

MARK PORTH: So those one-to-ones are still coming into Arkansas, but the ratio of demand is three-to-one. They need three loads for every one they pull in the summer.

DIRECTOR BENGAL: So the retailers in that part of the state have to go a fair distance --

MARK PORTH: Yes.

DIRECTOR BENGAL: -- to get their gas --

MARK PORTH: They're going to have to go to Conway, you know. That northwest Arkansas goes -- a lot of trucks go to Conway, Kansas, which is the second-largest storage facility in the world.

DIRECTOR BENGAL: Okay. Thank you.

MARK PORTH: Yeah. There's a lot of gas in Conway, Kansas that's available. It's just not local. And that comes back to our hours of service. Because they may send that truck to Conway, and that truck may sit for six or seven hours in line to be able to get its load. And with that, it's already used up all of its hours, so he hasn't made any miles at all, being able to deliver to fuel, other than sit in line. Yes.

DIRECTOR BENGAL: Thank you.

SECRETARY KEOGH: Director Pfalser, do you have follow-up questions?

DIRECTOR PFALSER: Yes. Thank you. Hey,

Mark, I appreciate you being with us today.

MARK PORTH: You bet.

DIRECTOR PFALSER: It's been -- it's been a little while since I have seen you because you've worked on the beard.

MARK PORTH: Well, I -- come -- just come December, I do don a red suit for a lot of short people, who are the most wonderful people you could ever, you know, be able to have the opportunity to spend a moment with.

DIRECTOR PFALSER: That's fantastic. We have talked before about this situation and about how CHS might strengthen their position within the state. And I understand that economics is what drives this and has to.

Have you discussed how a transloading operation, which would be, you know, a lot less expensive to facilitate, is that doable in your discussion? Have you had any discussions along those lines?

MARK PORTH: We sure have. We've looked at that in multiple locations to try to figure out how to make that work. And again, it's winter-only supply. If you're going to a -- to -- you're going to go to North Dakota, you're going to go to Calgary and ask for winter supply of rail cars, which is where a lot of those cars would come out of --

DIRECTOR PFALSER: Right.

MARK PORTH: -- the value that they tack onto that winter-only is -- makes it just almost cost prohibitive, to where you can easily put a truck on the road and run to Hattiesburg, run to Conway, run to wherever you need to go. You know, of course, we can always go to Mont Belvieu, Texas which, you know, fuel in southern Arkansas readily goes to Mont Belvieu to get its fuel --

DIRECTOR PFALSER: Right.

MARK PORTH: -- or some of the other locations that, you know, have storage.

And so, you know, we have looked at rail. We have looked at transloading. I know you guys -- you know, the LP Gas Board has been very progressive in trying to get transloading available. And when the economics work, I think that that would definitely be a great source.

But trying to source that on a -- and plan that to know that I'm going to need that transloader from December 15th through February 12th, how do you pay for it the other parts of the month or the rest of the year, is the difficult part of that.

DIRECTOR PFALSER: Is the actual piece of equipment, if there was spurs identified that could hold, you know, 10 to 20 cars, something like that, and it was already being utilized year-round for other purposes, but for a -- for a relative short period of time they could switch over and allow -- and allow you access for, you know, a 90-day window, would that be beneficial if those locations were already identified?

MARK PORTH: You bet. And we have -- we, CHS, have a couple of those already in place. We have agreements with the people that could possibly do that. We have equipment. We have the transloaders. It's just -- it's literally the supply side of that winter-only, deliver in the heart of the winter. The premium that is associated with those makes it difficult.

DIRECTOR PFALSER: I got you. I got you.

MARK PORTH: Doesn't make it economically -- you can easily drive a truck, you know. Yeah, a rail car brings three trucks at a time, but it's -- yes. I would -- we could have those sites if we had transloaders sitting, you know. They're $300,000 a piece for a transloader, is what one of those machines costs. So that's no small change either --

DIRECTOR PFALSER: No.

MARK PORTH: -- to have that asset sitting, not doing anything other months -- and rail economics can change. There used to be quite a bit of fuel that came in by rail to the state of Arkansas. But then we -- you know, there's an export facility that got put on the west coast that took a lot of the excess fuel that would normally come south into the states, is now going on -- is now on a ship headed to China.

DIRECTOR PFALSER: Yep. Yep.

MARK PORTH: Or the same thing happened over in the Marcellus, over in the Pennsylvania market where those rail cars would have normally come back into this, there's an new export facility that that fuel is easier and more economic to go to Japan than, you know, than to stay here in the states.

DIRECTOR PFALSER: One last thing, Mark. And I appreciate you talking to us about that.

MARK PORTH: You bet.

DIRECTOR PFALSER: The transporter -- transport situation, we -- we have probably three or four more companies this year starting in January than we did the last January that have received permits.

MARK PORTH: Great.

DIRECTOR PFALSER: So during the course of that -- that first couple of weeks in February, did you have trouble finding transportation?

MARK PORTH: Not really.

DIRECTOR PFALSER: Okay.

MARK PORTH: Yeah. Not really. Again, because we work very closely with our carriers. And you know -- and the carriers have the opportunity to have slack, you know. They may have -- that same pressure vessel may be hauling anhydrous, but then once winter arrives, they clean that trailer out and put a red tag 1075 on it and it's now hauling propane.

DIRECTOR PFALSER: Right.

MARK PORTH: So the carriers are our best friend, no doubt about it. And however we can make their lives easier would be a great benefit, whether that's helping them find qualified drivers and helping them retain those drivers or simply helping them with hours of service and not having the battle of, you know --

Again, propane has an incredible track record for safety. The people work really, really hard to remain safe. They're well trained. And but they're also motivated to take care of their customers.

And so if we can have carriers -- again, I come back around, the carriers are the key to it. And I'm not sure which one asked about how can we help with carriers, how can we help with drivers. But you are right in the middle of what we need, is qualified people who can get behind the steering wheel and drive, whether it's a transport or a bobtail or a service truck or any of the other pieces and parts. Qualified employees are very difficult to get and keep.

DIRECTOR PFALSER: Okay. Well, hey, Mark, again, I hope you understand how helpful you've been and I appreciate the time you've taken to be with us. And I might be reaching back out as we move through this process.

And I'll turn it back over to Secretary Keogh at this time.

SECRETARY KEOGH: Thank you, again, for your helpful information. And I would encourage you two to talk and communicate if there's additional thoughts that come to mind. This is not an ending point. It's really a starting point for us to be able to compile this set of recommendations and obviously, set conversation forward so that we -- I believe open communication will help us, not only for this event but in future events.

I think, part of us, having not gone through one recently, a lot of -- those venues of communication had to be established. Again, I appreciate the participation --

MARK PORTH: You bet.

SECRETARY KEOGH: -- and those that are involved in it. So thank you. I think that will --

MARK PORTH: Like I said in my opening statement, I cover a lot of ground. I cover a lot of different states. And I sit on the board of directors for almost all of those states. And Arkansas is the only one that's doing something like this. You guys are ahead of the game. And I applaud you for trying to find out and figure out how to do it better.

Good job. Good job. And I am happy to help. I -- you know, I've been selling propane a long time and see a lot of different things. And Kevin is a great resource for you guys. We've known each other a long time and he's a good guy with extensive knowledge. So that's why he's sitting in the seat that he is.

And so, but yes, I'm happy to help wherever I can.

SECRETARY KEOGH: All right. Well, I want to thank you. I want to thank our Task Force members who have been diligent in this process and been available to -- thank you for, you know, Secretary Preston, I know he had a number of pressures on his schedule this week, as well as -- and thank you Director Sparks for joining in with us, and Director Bengal, Director Pfalser.

I know we had the services of Arkansas PBS helping live stream this to our citizens, which hopefully, for those that are interested, I know we've had participation ranging from state agencies to natural gas suppliers to our utility, electric utility generators and transmission, down to some of the propane industry and natural gas pipeline.

So a lot of activity around energy resources, but I think the success story is that Arkansas is blessed with energy resources. We're blessed with great providers and producers. And we hope that, as you said, Mark, that our efforts are to move forward in making sure that Arkansas is a great place to live. It's a great place to work. And it's a great place to recreate. So we encourage you to come visit us some time if you haven't, for tourism.

With that, we will close out our official hearing and look forward to follow-up conversations through our staff to the Task Force members as we begin to evaluate what we've heard over the last three days of hearings.

Thank you so much, Mark. And I will end the hearing at this point and we'll close off the Zoom link at this point as well. Thank you.

(Whereupon the proceedings were adjourned.)

REPORTER'S CERTIFICATE

STATE OF ARKANSAS)
) Ss:
COUNTY OF PULASKI)

I, KARISA J. EKENSEAIR, Certified Court Reporter, Registered Professional Reporter in and for the State of Arkansas, do hereby certify that the proceedings were taken by me in stenotype and was thereafter reduced to typewritten form by me or under my direction and supervision; that the foregoing transcript is a true and accurate record of the testimony given to the best of my understanding and ability.

I FURTHER CERTIFY that I am neither counsel for, related to, nor employed by any of the parties to the action in which this proceeding was taken; and, further, that I am not a relative or employee of any attorney or counsel employed by the parties hereto, nor financially interested, or otherwise, in the outcome of this action; and that I have no contract with the parties, attorneys or persons with an interest in the action that affects or has a substantial tendency to affect impartiality, that requires me to relinquish control of an original deposition transcript or copies of the transcript before it is certified and delivered to the custodial attorney, or that requires me to provide any service not made available to all parties to the action.

IN ACCORDANCE with Rule 30(e) of the Rules of Civil Procedure, review of the transcript was not requested.

GIVEN UNDER MY HAND and SEAL OF OFFICE on this 15th day of June, 2021.

KARISA EKENSEAIR ARKANSAS SUPREME COURT NO. 802 CERTIFIED COURT REPORTER

KARISA EKENSEAIR
Notary Public - Arkansas
Pulaski County
My Commission Expires 06-18-2028
Commission # 12704567

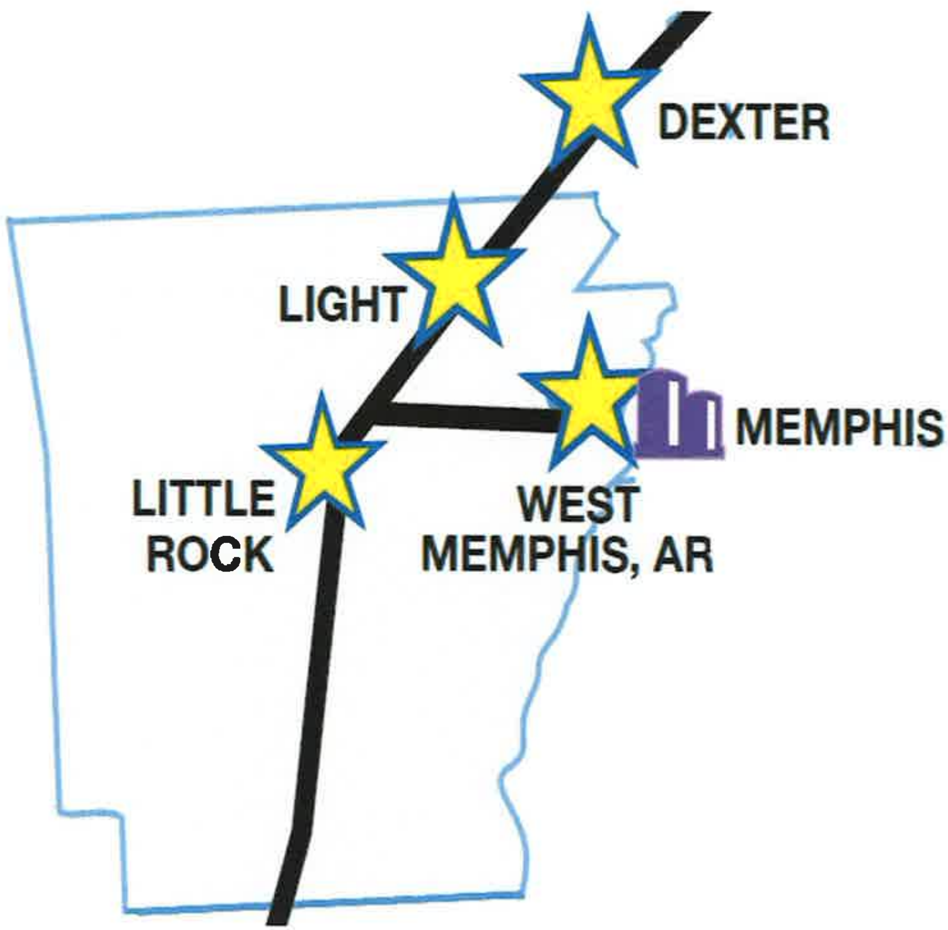
Karisa Ekenseair, CCR, RPR LS #802
Notary Public in and for
Pulaski County, Arkansas
Commission No. 12704567
Exp. 06-18-2028

NGL SUPPLY WHOLESALE, LLC

Arkansas Energy Resources Planning Task Force

June 2, 2021

NGL Energy Partners Arkansas Propane Asset Summary



- Dexter
  - Pipeline and truck supplied
  - 1,170,000 gallons storage
- Light / Bono
  - Pipeline and truck supplied
  - 900,000 gallons storage
- Little Rock
  - Rail and truck supplied
  - 90,000 gallons storage
  - Railcar siding 10 onsite / 20 offsite
- West Memphis
  - Pipeline and truck supplied
  - 2,865,000 gallons storage

Arkansas Propane Supply Influences

- TEPPCO Pipeline
  - Mont Belvieu, TX is the only source
  - Nominate on 15th month prior
  - Shipping cycle every 10 days
  - 10-12 days transit
- Rail
  - Conway, KS 10-15 days transit
  - Bakken, ND 15-25 days transit
  - Chicago, IL   7-10 days transit
- Truck
  - Refineries: Memphis, Coffeyville, Tulsa, Wood River, El Dorado
  - Pipelines: East St. Louis, Carthage, Hattiesburg, Demopolis
  - Barge: Greenville

NGL SUPPLY WHOLESALE, LLC

February 2021 Challenges

- February deep freeze was not well forecasted
- Heating Degree Days
  - February 21 815
  - 5 year avg 546
  - 20 year avg 587

- February 21 sales were 25% higher than February 20
- Hazardous roads made it difficult for trucks to make it to our terminals
- February pipe batch delayed a week due to cold weather causing pump issues at Mont Belvieu
- Valero refinery had a small explosion February 15th shutting in propane production until March 9th

Recommendations

- Increased bulk plant storage
  - Low cost loans
  - Subsidized loans
- Carriers
  - Temporary GVW waivers
  - Timely exemptions for driver hours
  - Arkansas is short propane carriers

Questions

MEETING REGISTRATION SHEET
ENERGY RESOURCES PLANNING TASK FORCE

DATE: ______________

LOCATION: ______________

PAGE: ____ OF ____

NAME (PLEASE PRINT LEGIBLY)	ENTITY	CONTACT (EMAIL, PHONE)
Daryl Brown	MISO	dbrown@misoenergy.org 501-804-1187
Steve Cousins	AEEC AGC	stevencousins@outlook.com 870 310 4262
Shawn McMurray	AEEC AGC	shawn@TYAttorney.com 501-374-2099
Randy Bynum	Dover Dixon Horne	rbynum@ddh.law 501-[illegible]-8790
Madison Wright	Dover Dixon Horne	madisonwright@gmail.com 501-681-1551
Steve Sparks for Sec. Mike Preston	AEDC	ssparks@arkansasedc.com 501-682-1350
Chuck Harder	Attorney General's Office	chuck.harder@arkansasag.gov (501) 682-4058
[illegible]	SPP	[illegible]@spp.org 501 688-2533
[illegible]	ArkAG	323 Center St. LR 502-~~[illegible]~~ 602 5025
Chairman Ted Thomas	PSC	
Caleb Stanton	Governor's Office	
Brent Stevenson	Ark Forest & Paper Council	
Buddy Allen	" "	
Ava Roberts	AEF	501-920-3963

MEETING REGISTRATION SHEET
ENERGY RESOURCES PLANNING TASK FORCE

DATE: ____________________

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NAME (PLEASE PRINT LEGIBLY)	**ENTITY**	**CONTACT** (EMAIL, PHONE)
Mike Ross	SPP	mross@spp.org
Trent Minner	Ark Ag	trent.minner@arkansasag.gov
Leslie Davis	Harbor / AEF	ldavis@harborenv.com
Michael Hester	QG+T	mhester@qgtlaw.com

MEETING REGISTRATION SHEET
ENERGY RESOURCES PLANNING TASK FORCE

DATE: 06-01-21

LOCATION: Department of Energy and Environment

PAGE: 1 OF ___

NAME (PLEASE PRINT LEGIBLY)	ENTITY	CONTACT (EMAIL, PHONE)
Scott Sefton	Ozark Mtn. Petroleum	870-213-6920
Kevin Pfalser	LP-GAS Board	
Shane Khoury	E&E	
Dan Pilkington	E&E	
JEFF Applekamp	Enable Midstream Partners	918-760-4950
Robin Craft	Craft Propane Inc	rcraft propane @ suddenlinkmail.com
Steve Sparks	AEDC	ssparks@arkansasedc.com
AARON REECE	NGL Supply Wholesale	918-851-0674
Laneigh Pfalser	AR Propane Gas Association	501-743-5035

MEETING REGISTRATION SHEET
ENERGY RESOURCES PLANNING TASK FORCE

DATE: 01 JUNE 2021

LOCATION: ARK DEPT ENERGY & ENVIRONMENT

PAGE: 1 **OF** ___

NAME (PLEASE PRINT LEGIBLY)	ENTITY	CONTACT (EMAIL, PHONE)
DONALD ROWLETT	OKLAHOMA GAS AND ELECTRIC COMPANY (OG+E)	rowletdr@oge.com 405 553.3604
Amanda Story	Hargraves Consulting (Liberty)	amanda@hargraves consulting.com 870-589-0277
Andrew Lachowsky	Ark. Electric Coop Corp	alachowsky@aecc.com (501) 570-2435

MEETING REGISTRATION SHEET
ENERGY RESOURCES PLANNING TASK FORCE

DATE: 6/1/2021

LOCATION:

PAGE: ____ **OF** ____

NAME (PLEASE PRINT LEGIBLY)	ENTITY	CONTACT (EMAIL, PHONE)
Chad Kinsley	Black Hills Energy	605-580-6782
David Brink	" "	DBrink@BlackHillsEnergy.com
Charles Spek	" " " "	
Kevin Pfalser	AR GAS BOARD	Kevin.Pfalser@ArkansasGasBoard.com
James Miller	AOG	
Miles Kenny	CenterPoint	713-299-2503
Rodney Baker	AIPRO	501-607-4245
Steve Goode	Miller & Associates	501-514-2013
Cindy Westcott	CenterPoint Energy	501 377 4875
Tom Stevens	Black Hills Energy	479-409-7580
Erica Mahony	CenterPoint	501-377-4549
Mike Preston	Commerce	501-370-6398
Shane Khoury	E&E	
Dan Pilkinton	E&E	

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NAME (PLEASE PRINT LEGIBLY)	**ENTITY**	**CONTACT** (EMAIL, PHONE)
Steve Sparks	AEDC for Mike Preston	Sparks@arkansasedc.com
Bradley Hardin	SWEPCO	behardin@aep.com
Randy Thurman	OG&E	rthurman@arkansaslobbying.com
John Peiserl	PPGMR	john@ppgmrlaw.com
Mike Nasi	Life:Powered/EPN	mnasi@jw.com
Randy Eminger	Energy Policy Network	806-674-7089 reminger@tepn.org
Laura Landreaux	Entergy Arkansas	501-349-6810

APPENDIX C. WRITTEN TESTIMONY AND ASSOCIATED DOCUMENTS

ARKANSAS
ENERGY & ENVIRONMENT

April 9, 2021

Greetings:

On March 3, 2021, Governor Asa Hutchinson signed Executive Order 21-05 to establish the Energy Resources Planning Task Force. The Task Force, of which I have the honor of chairing, is made up of the Arkansas Department of Energy and Environment, the Oil and Gas Commission, the Liquefied Petroleum Gas Board, and the Department of Commerce. The Task Force will review lessons learned from the February winter storms, including those from surrounding states, and gather information from pre-filed responses and hearing testimony.

On behalf of the Task Force members, I am pleased to invite you to provide valuable input that will be sent to Governor Hutchinson upon the completion of our report, which is due on September 30, 2021. As Chair of the Task Force, I respectfully request that your written responses to the attached testimony questions be sent to ERPTaskForce@arkansas.gov on or before **April 30, 2021**. While there will be an opportunity for public testimony at a date to be determined, your pre-filed responses will ensure that our report to the Governor reflects the Task Force's most comprehensive and judicious recommendations and priorities.

Your participation is key as we look for solutions to better prepare our state's energy infrastructure in the event of another statewide emergency. Thank you for your time and consideration of this important matter.

Sincerely,

Becky W. Keogh

Becky W. Keogh
Cabinet Secretary, Arkansas Energy & Environment
Chair, Energy Resources Planning Task Force

Energy Resources Planning Task Force

Response to Testimony Questions of Ted Thomas, Chairman, Arkansas Public Service Commission[1]:

1. Please summarize the Public Service Commission's understanding of the causes of the electric and natural gas shortages that occurred during the February winter weather event.

Record cold temperatures caused record demand for energy while also severely disrupting natural gas production[2]. Although review is ongoing, Southwest Power Pool independent market monitor Keith Collins states, "Fuel supply issues, primarily natural gas, were a primary cause of outages and resource scarcity."[3] This is best demonstrated by review of the gas production charts on page 8 of the American Gas Association presentation and on page 3 of the SPP independent market monitor report. Final conclusions about the causes of the electric and natural gas shortages should be made only upon completion of the various pending investigations.

2. Please summarize the policies, programs, procedures or technical aspects that Arkansas had in place that, in comparison to other states, minimized the power shortage impacts in Arkansas during the February winter weather event.

All utilities in Arkansas are members of one of the two Regional Transmission Organizations (RTO) in Arkansas, Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO). Roughly speaking, the SPP area of Arkansas includes the SWEPCO, OG&E, Empire District and municipal utilities surrounded by those service

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[1] The views expressed in this document are the views of Ted Thomas, not the Arkansas Public Service Commission.
[2] See *The Effects of Winter Storm Uri on Natural Gas Utilities* slide presentation from the American Gas Association on April 21, 2021 to the NARUC Committee on Gas, pages 3 and 8. The full slide deck is attached hereto.
[3] *Market Review of Winter Event* slide presentation to the Southwest Power Pool RSC (State Regulator stakeholder group in SPP) by Keith Collins, independent Market Monitor for SPP at page 16. The full slide deck is attached hereto.

territories and the MISO area of Arkansas includes the Entergy service territory and municipal utilities surrounded by that service territory. Electric cooperatives are in some ways managed as if they are in both RTOs and in other ways those cooperatives closest to SPP territory are in SPP and likewise for MISO.

An RTO is a non-profit entity that manages the grid that is owned by utilities to ensure that generation resources have access to the grid even if the generation asset is owned by an entity other than the utility that owns the transmission assets. This allows for a wholesale electricity market and regional transmission planning which are managed by the RTO.

“Reserve margin” is (capacity minus demand)/demand, where "capacity" is the expected maximum available supply and "demand" is expected peak demand. It is calculated for electric systems or regions made up of a number of electric systems. By definition, a smaller geographic area has a higher reserve margin than a larger geographic area. In an RTO, the reserve margin is calculated for the entire RTO, not for individual state utilities within the RTO. A lower reserve margin means that fewer resources are needed and the resulting cost savings is the primary reason for joining an RTO.

A state loses some degree of autonomy when its utilities join an RTO because system reliability is then measured on an RTO basis and not a state specific basis. Each state’s policy contributes to the RTO’s reliability but the transmission system is managed on a regional basis, thus when both RTOs had load shed events the rolling blackouts were done proportionally across the region[4] rather than on a state basis. While states maintain jurisdiction over generation recourses, usually through a planning process called integrated resource planning, those state specified resources are managed collectively by the RTOs.

[4] In SPP, the load shed event was distributed to the entire footprint. In MISO, the load shed event was limited to MISO south because of transmission constraints between MISO north and MISO south.

A comparison of reliability between states in the same RTO cannot be made in that each state in the RTO has the same reliability because the grid is managed on a regional basis.   However, a regional comparison can be made between SPP, MISO and ERCOT, the RTO that manages the grid in most of Texas.

Generally speaking, comparisons of RTO performance during the winter weather event were driven by geography. The temperature's impact on load and fuel availability was worse to the west and south of the combined SPP, MISO and ERCOT region. The ability to import electricity from other regions was also less the in the south and west of the combined region. As a result the outages and cost spikes were less severe in MISO, more severe in SPP and most severe in ERCOT.

In SPP a more significant load shed event was avoided by imports from other regions[5]. Furthermore, the load shed events in SPP were highly correlated with import curtailments because of transmission constraints in MISO[6], which borders SPP to the east. Electricity was being imported to SPP from MISO and PJM, the RTO to the east of MISO. On page 9 of the referenced slide deck, both of the load shed events are marked in yellow and are preceded by reductions in imports.

MISO south had a load shed and MISO north did not. This is because of transmission constraints between MISO south and MISO north as demonstrated by the MISO independent market monitor's focus on transmission in the "lessons learned" report submitted to MISO board of directors[7].

[5] *Market Review of Winter Event* slide presentation to the Southwest Power Pool RSC (State Regulator stakeholder group in SPP) by Keith Collins, independent Market Monitor for SPP at page 8.

[6] *Market Review of Winter Event* slide presentation to the Southwest Power Pool RSC (State Regulator stakeholder group in SPP) by Keith Collins, independent Market Monitor for SPP at page 9.

[7] *IMM Quarterly Report: Winter 2021* slide presentation to the MISO Markets Committed by Dr. David Patton, independent market monitor for MISO at page 10-11. The full slide deck is attached hereto.

The ERCOT regions of Texas, which includes the major metropolitan areas of Texas and approximately 80% of the load, has a unique jurisdictional arrangement whereby they are not subject to FERC jurisdiction because power flows in ERCOT are not in interstate commerce because the ERCOT grid is fully severable from the rest of the electric grid. The limited ability to import electricity from other regions contributed to the severity of the event in Texas, as did lack of winterization of electric generating assets as well as natural gas production assets.

3. To what extent did the implementation of energy efficiency programs by the utilities in accordance with the Public Service Commission rules reduce the need to shed load during the February winter weather event? Are their changes to the energy efficiency rules, targets or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

Energy efficiency programs are designed to reduce consumption in order to save costs related to the production of energy and costs related to having the capacity on hand at any moment to produce enough energy to meet all of the demand for energy without waiting in line. Electricity efficiency savings are measured both in terms of MWh of energy used and in terms of MW of capacity, the amount of resources needed at peak so that anyone can use as much as they want without waiting. Natural gas efficiency savings are measured in therms which is a measurement of heat produced by burning a standard unit of natural gas.

In May of each year the seven investor-owned electric and gas utilities report to the Public Service Commission on the verified energy savings achieved during the prior year's Energy Efficiency Programs. The electric utilities also report on the demand savings achieved by the programs. The results shown below indicate a total demand savings of 99 MW in 2019 for the three largest electric utilities, Entergy (78 MW), SWEPCO (16 MW), and Oklahoma Gas & Electric Company (5 MW). The 2021 energy and demand savings realized, including the effects of the February 2021 winter event will not be measured, evaluated, and reported on until May 2022. Results achieved during 2020 will be reported by the utilities on May 3, 2021. Owing to the Covid-19 pandemic and the ongoing requirements for social distancing and the impact the pandemic has had on business operations, it is possible that the energy and demand savings achieved by the utilities in 2020 will not substantially resemble the results for energy and demand savings for 2019 and previous years.

The Commission has now pending a docket (No. 21-036-U) in which the utilities are being asked to report on the causes and impacts of the Winter Weather Event and may be requested to provide information regarding how the energy efficiency programs performed in producing a demand reduction on the electric systems during the Event, especially given the impact on winter electric heating loads during the extreme cold. It seems likely that energy efficiency programs targeting direct load control (e.g., dispatchable smart thermostats) and residential and commercial weatherization and HVAC tune-ups and highly-efficient HVAC upgrades/replacements contributed to electric loads being lower than would otherwise have been the case in February's Event.

Even before the Winter Weather Event, the topic of how utility energy efficiency measures and programs can provide electricity demand reductions as well as energy savings is receiving considerable attention. See the December 23, 2020 PowerPoint update to a 2019 Report by the Lawrence Berkeley National Laboratory on "Peak Demand Savings from Efficiency: Opportunities and Practices" at:

https://eta-publications.lbl.gov/sites/default/files/peak_demand_21_01_07_report.pdf The update includes input on the results from Entergy Arkansas, LLC's energy efficiency programs, as well as those of 51 other large utilities. See also a report issued on April 15, 2021, by the American Council for an Energy-Efficient Economy: "Utilities Can Lessen Winter Power Outage Risk by Investing in Home Efficiency": https://www2.aceee.org/webmail/310911/826688635/a68cbab6c8aea86ae3a5f1083b15ddb79d72276c5db8ee4e5a486d079b6fc0f5

Tables 1 thru 4 below demonstrate the reported savings for the Arkansas 2019 Energy Efficiency Programs and a comparison to prior years' savings.

Table 1 – 2019 Demand and Energy Savings for Electric Utilities

Electric Utility	Net Energy Savings	
	Demand MW	Energy MWH
Entergy	78	248,663
SWEPCO	16	35,952
OG&E	5	26,071
Empire	0	320
TOTAL Arkansas	**98**	**311,006**

Table 2 – Five-Year Energy Savings for Electric Utilities

Savings (MWh)	PY 2014	PY 2015	PY 2016	PY 2017	PY 2018	PY 2019
Entergy	205,507	230,341	253,290	264,992	255,997	248,663
SWEPCO	30,056	31,462	34,357	33,667	36,735	35,952
OG&E	13,794	20,543	23,257	21,131	22,557	26,071
EMPIRE	147	212	220	155	210	320
Total	**249,504**	**282,558**	**311,124**	**319,945**	**315,499**	**311,006**

Table 3 – 2019 Energy Savings for Gas Utilities

Natural Gas Utility	Net Energy Savings
	Energy Therms
CenterPoint	3,831,747
Black Hills	1,268,914
AOG	492,071
TOTAL Arkansas	**5,592,732**

Table 4 – 5-Year Energy Savings for Gas Utilities

Savings (Therms)	PY 2014	PY 2015	PY 2016	PY 2017	PY 2018	PY 2019
CenterPoint	2,743,851	2,938,212	2,963,465	3,423,918	3,790,589	3,831,747
Black Hills	1,138,776	1,417,271	1,540,466	1,261,851	1,262,524	1,268,914
AOG	591,591	535,479	534,421	536,202	500,829	492,071
Total	**4,474,218**	**4,890,962**	**5,038,352**	**5,221,971**	**5,553,942**	**5,592,732**

As discussed above, reliability is managed on a regional basis by RTOs. While the cost savings of the energy efficiency program flow to Arkansas utility customers, the reliability benefits are shared regionally. Reductions in demand in the Entergy service territory reduced the load shed event in MISO south by 78 MW and the load shed event in SPP by 21 MW when compared with baseline usage that existed prior to the implementation of the efficiency program. But for the efficiency program, the load shed caused by the winter weather event would have been larger.

4. Please briefly summarize the issues that the Public Service Commission will examine with respect to understanding in more detail the power shortage events that occurred during the February winter weather event.

The Arkansas Public Service Commission will investigate in detail the preparation, response, operational performance, and communication practices regarding the winter weather event with respect to electric and natural gas utilities and RTOs in Arkansas. A commission order stating the scope of the investigation will be issued on the near term and this answer will be updated with a copy of that order.

5. Are there any recommendations that the Public Service Commission would like to present to the Task Force in regard to addressing energy supplies during extreme events?

First, policy recommendations regarding the winter storm event should be considered in conjunction with other related policy issues, particularly the climate policy of the new federal administration. Intermittent renewable resources can cause reliability problems at high levels of penetration, yet such resources can mitigate the cost of compliance with expected federal carbon regulation. Placing reliability issues and carbon issues in separate silos would be a significant mistake.

Given that aspects of reliability are managed on a regional basis, continued engagement in the RTO stakeholder processes that are study these issues is essential. Also essential is that questions involving system reliability be addressed by applying rigorous engineering standards, not by the application of political muscle. The rigor brought by the RTOs to this subject matter is demonstrated by the attached documents *Integrated Markets and Operations Update* dated April 26, 2021 and *MISO's Renewable Integration Impact Assessment (RIIA) Executive Summary* dated February 2021.

Second, the "stupid fuel wars" debate approach will bring neither reliability nor emission reductions. The "fuel wars" is my description of corporate and industrial trade group public relations efforts regarding the national climate debate, elements of which have entered the reliability debate prompted by the February winter weather event. The fuel wars debate approach focuses on soft positive reaction to industry groups rather than effective policy debate. I refer to the fuel wars as stupid because in the context of the climate debate this approach has failed to associate calls for climate “action” with potentially large increases in costs to consumers.

The failure of this approach can be demonstrated by the shift in public attitudes regarding climate policy over the past several years and the failure to attempt to include cost to consumers when measuring public opinion on climate policy. The failed public relations strategy of the American Petroleum Institute (API) is symbolic of industries failure to stand up for its customers. API recently announced that it supported the concept of a carbon tax, presumably to accommodate public opinion on the climate issue. Cost will be imposed on consumers with no promise of a solution to the problem and no discussion of international cost allocation issues that have yet to be resolved. Write a check first, solve the problem later. The “stupid fuel wars” approach has been a failure with respect to the climate debate and it will also fail with respect to examination of system reliability of the winter weather event.

Third, a reliable, cost effective system that complies with expected federal carbon mandates is in my view achievable only through policy that rigorously examines all possible new and existing technologies. This will only occur if decisions are made based on engineering and economics rather than by political muscle.

Resource Adequacy Reforms

OMS Spring Seminar

May 24, 2021

Purpose & Key Takeaways

Key Takeaways:

- MISO is looking at refinements to the accreditation proposal that meaningfully address stakeholder concerns while sufficiently mitigating reliability risks
- MISO has extended overall timeline to allow sufficient stakeholder engagement to support a FERC filing now planned for September 2021
- Directional changes were shared at a RAN workshop on May 21st ; these preliminary design changes will continue to be refined with additional detail for the June RASC

MISO will increase transparency in the planning horizon coupled with market price signals to incent needed resource capabilities

Current Hypothesis

Market Redefinition

RESOURCE ASSESSMENT

MISO will provide a forward assessment to provide stakeholders with transparency of forecasted system needs (for capacity and flexibility) versus expected system capabilities based on the aggregation of member plans

MEMBER CAPACITY TO MEET FORECASTED NEEDS

Proposing changes to the current RA construct to assess members' capacity to meet forecasted needs; Planning to move to sub-annual Planning Resource Auction (PRA) construct

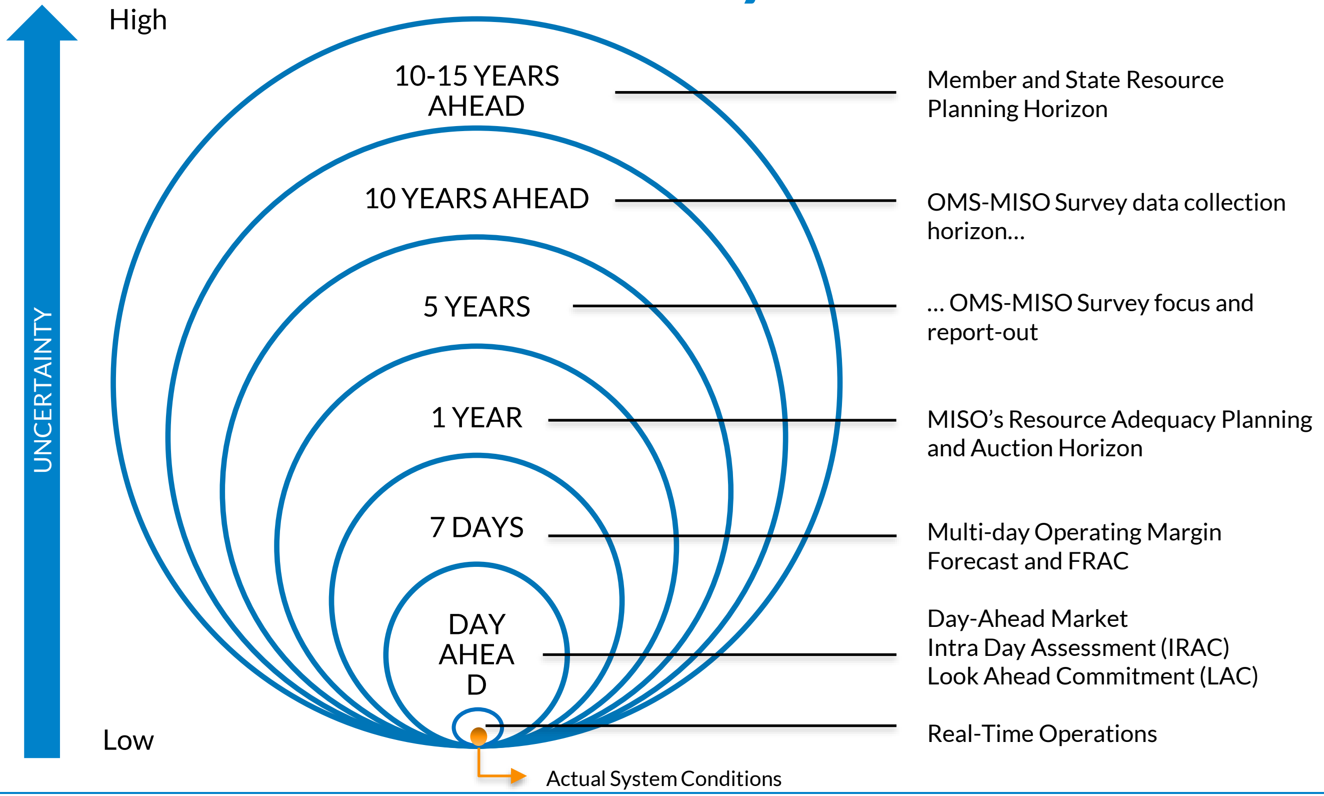
PRA MECHANISM AND AUCTION STRUCTURE

PRA process remains as mechanism to ensure compliance with reserve margin requirement with no substantive changes to auction structure

INCREASED RELIANCE ON ENERGY MARKET SIGNALS

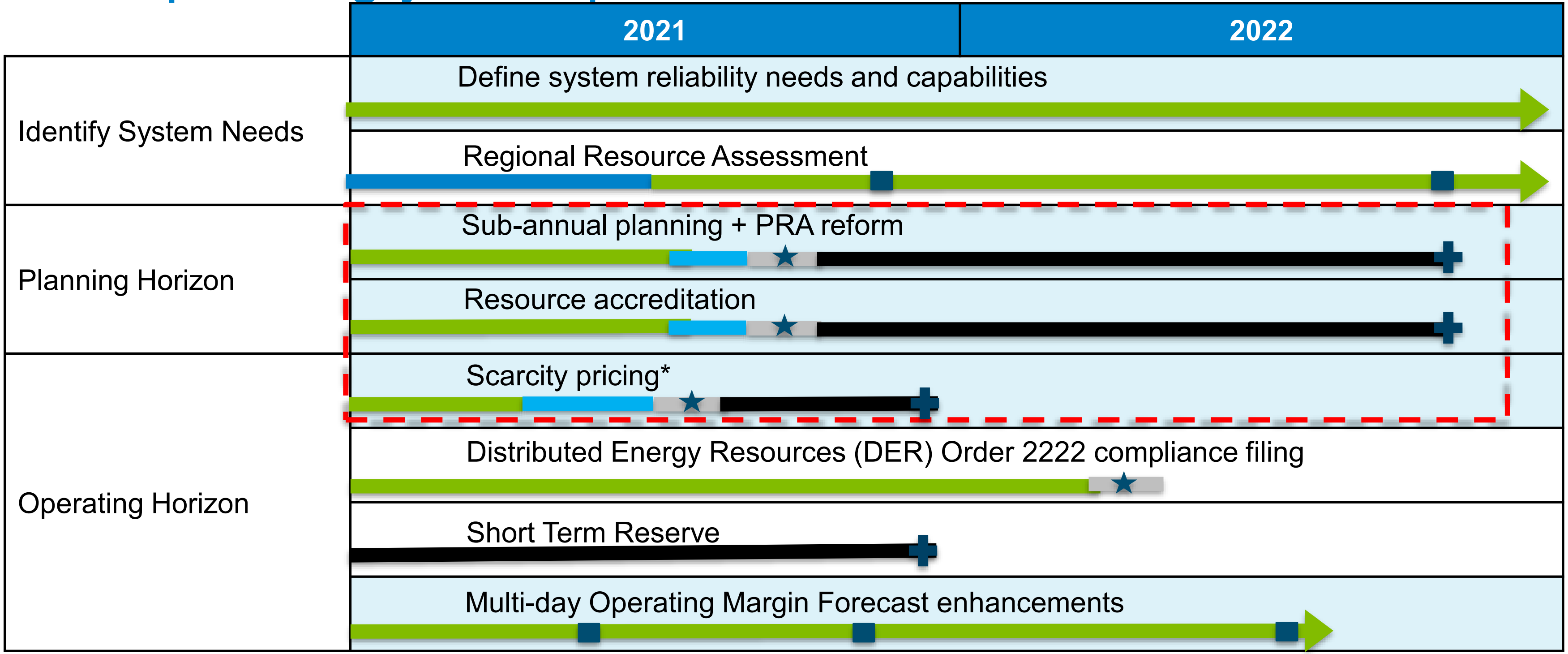
Energy markets to address the challenges of the changing fleet; leverage energy and ancillary service markets to incentivize resources to provide sufficient energy and ramping capabilities in the operating horizon

Resource Availability timeline



OMS = Organization of MISO States FRAC = Multi-day Forward Reliability Assessment Commitment IRAC = Intra Day Assessment Commitment

MISO is working with stakeholders on multiple FERC filings (dotted red lines) in Q2 and Q3 of 2021 targeting a 2023-2024 planning year implementation



Stakeholder engagement
Frame & evaluate stages
Conceptual design
Build solution
Approximate target for FERC filing
Part of RAN initiative
Implementation
Report release
* Same implementation date for Emergency Pricing filed 12/21

5

LOLE analysis to set seasonal requirements

MISO proposes a range of design elements to determine seasonal resource adequacy requirements to reflect analysis findings and stakeholder feedback

	MISO Proposal	Rationale	Preliminary findings
Seasonal Risk Target	Round seasonal targets up to a minimum 0.01 without adjusting other seasons' Loss of Load Expectation (LOLE) target if greater than 0.01	Avoid artificially inflating requirements for seasons with risks greater than 0.01 Meet the BAL-502-RF standard requirement	Increase in requirement may not be trivial if adjusting seasons with LOLE risks greater than 0.01 to compensate for having minimum 0.01 in other seasons
Season Definition	Include September in Summer season	September load shapes generally resemble summer month load shapes	Notable decrease in Fall resource adequacy requirements with minimal impact on summer requirements
Seasonal CIL/CEL	Conduct seasonal transfer limit analysis to determine seasonal CIL/CEL	Capture seasonality of transfer limits in determining Local Clearing Requirements	Variation observed in seasonal transfer limits driven by seasonal conditions

MISO proposes to round seasonal LOLE risk targets up to a minimum 0.01 to set seasonal resource adequacy requirements PRM/LRRs

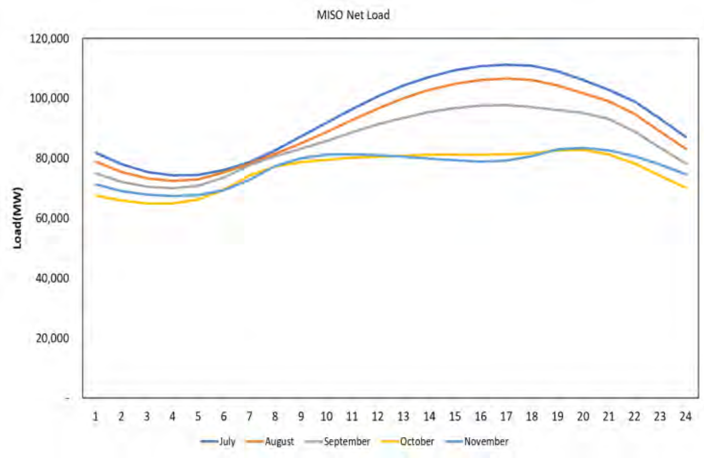
The goal of setting seasonal risk targets is to determine seasonal resource adequacy reserve requirements PRM/LRRs

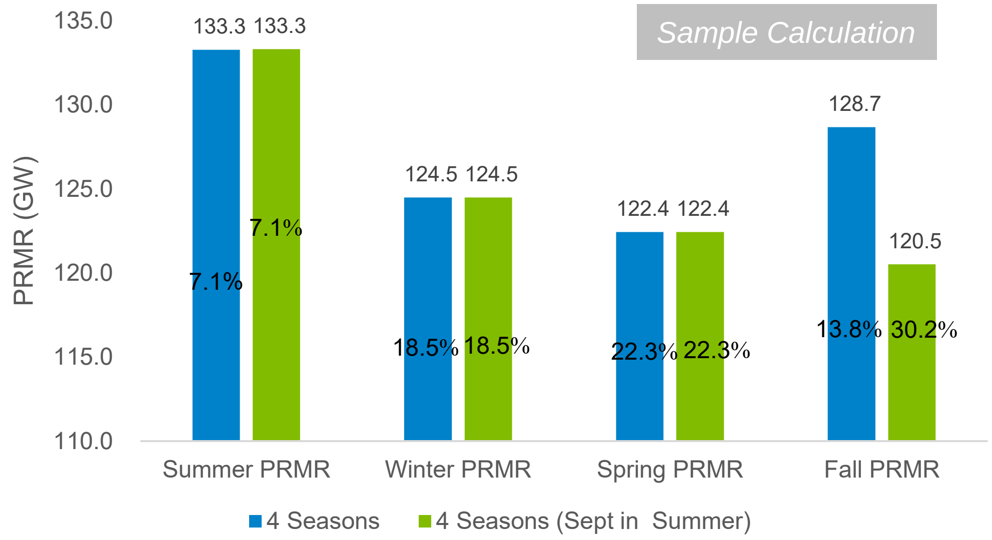
Options	Pros	Cons
Round seasonal targets up to a minimum 0.01 without adjusting other seasons' LOLE	• Only requires an additional modeling run for seasons with LOLE <0.01 • Keep reserve requirements for the seasons with risks as is • Meet the BAL-502-RF standard requirement	• Results in an annual LOLE slightly above 0.1d/year standard
Round seasonal targets up to a minimum 0.01 and adjust other seasons' targets down to maintain a 0.1d/year annual LOLE	• Total 0.1d/year annual LOLE • Meet the BAL-502-RF standard requirement	• Requires additional runs for all seasons to rebalance seasonal targets to meet 0.1 annual LOLE • Increase requirements for seasons where there are risks and procure more capacity than needed, which can be costly

	0.1 Summer LOLE Target*	0.07 Summer LOLE Target*	Difference
PRM %	7.1%	7.7%	0.6%
Summer PRMR (GW)	133.3	134.0	0.7

* The analysis is based on PY21 sub-annual LOLE modeling assumptions
PRM = Planning Reserve Margin | LRR = Local Resource Requirement

MISO is recommending including the month of September to the summer season





- September load shape more closely resembles the summer month load shapes
- Notable decrease in Fall resource adequacy requirements with minimal impact on summer requirements

- The analysis is based on PY21 sub-annual LOLE modeling assumptions
- PRMR – Planning Reserve Margin Requirement

Revised resource accreditation proposal

MISO proposes refinements to the accreditation proposal that meaningfully address stakeholder concerns while sufficiently mitigating reliability risks

	Proposal presented at Feb RASC	Current Revised Proposal	Address Stakeholder Concerns
Hour Selection	Availability during top 5% of tightest hours across the year	Availability across all hours with a two-tiered weighting structure between tight condition hours and non-tight hours	Focus on availability during times of need while reflecting general availability across the year
Recognize coordinated outage planning	N/A	Leverage and enhance RAN Phase I outage planning processes; Include planned outage exemption rules; Refine planned outage modeling in LOLE	Recognize and enhance prudent outage planning; better align modeled and actual outages
Stability in RA planning	Small set of tightest hours selected over three-year period	Account for all hours across the year over a rolling three-year period	Reduce year to year volatility in seasonal accreditation values
Lead time of offline resources	24 hours for identifying tight condition hours, not considered for accreditation calculation	24 hours for identifying tight condition hours and calculating accreditation	Better align with Day Ahead market processes, will monitor and enhance as resource mix evolves

MISO is refining planned outage treatment by leveraging and bolstering RAN Phase 1 provisions

Address Existing Gaps

- Validate how outages* are treated in CROW
- Tighten up language around coding outages
- Improve supporting process for verification and penalties

Develop Enhancements

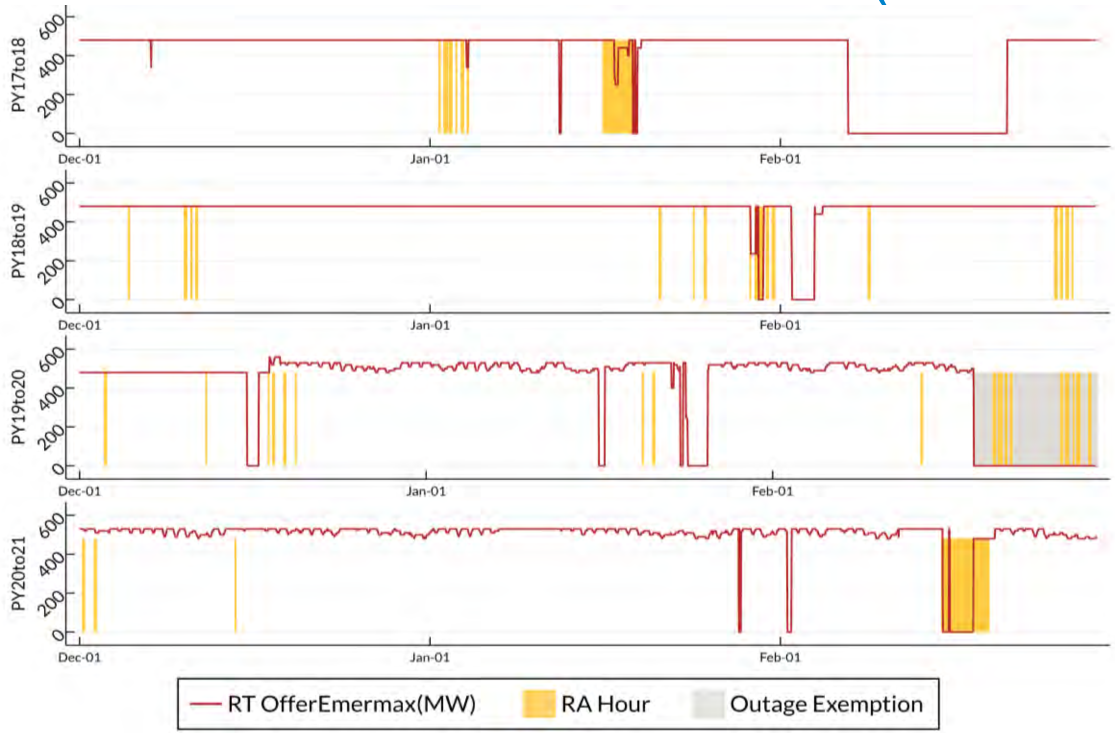
- Expansion of hours applicable for RAN Phase I provisions
- Bolster magnitude of accreditation penalties
- Limit on total MWs of outages and outage extensions

Outages* includes forced and planned outages and de-rates

Proposed enhancements to RAN Phase I are incorporated into the revised proposal

- Address Existing Gaps:
  - Validate: By using offers, de-rates only have a pro rata impact on accreditation as intended
  - Tighten: The revised proposal ensures all non-exempt (insufficiently coordinated) outages are treated like forced outages when they overlap with capacity emergency conditions
  - Improve: The revised proposal accounts for unreported or misreported outages which have been a significant issue based on reporting by the IMM
- Develop Further Enhancements:
  - Expand: The revised proposal considers non-MaxGen tight hours such as conservative ops in addition to MaxGen alerts/warning/events as recently recommended by some stakeholders
  - Bolster: Under RAN Phase 1 non-exempt outages during times of need typically only had a 0.1%/day impact to accreditation
    - Under the revised proposal a tiered approach focused on the tightest 3% of hours creates a 33x multiple that is then discounted by the weighting between the tiers
  - Limit: To support reliability and equity, the revised proposal limits exempt outages regionally and requires reasonable expectation of seasonal availability to participate in each auction

RA hours that occur when a resource is on an exempt outage or didn't clear the seasonal auction are removed from accreditation assessments (illustration for a single resource)



Winter	RA Hours	Exempt* Hours
PY 18-19	87	0
PY 19-20	64	34
PY 20-21	65	0

For tier 2 the proposal only considers RT offers in non-exempt hours which would be 30 hours in PY 19-20

*There are no exempt hours prior to spring 2019 when RAN Phase 1 was approved

Tier 2 tight condition hours are defined across the year based on retrospective tight supply time periods and MaxGen event hours[1]

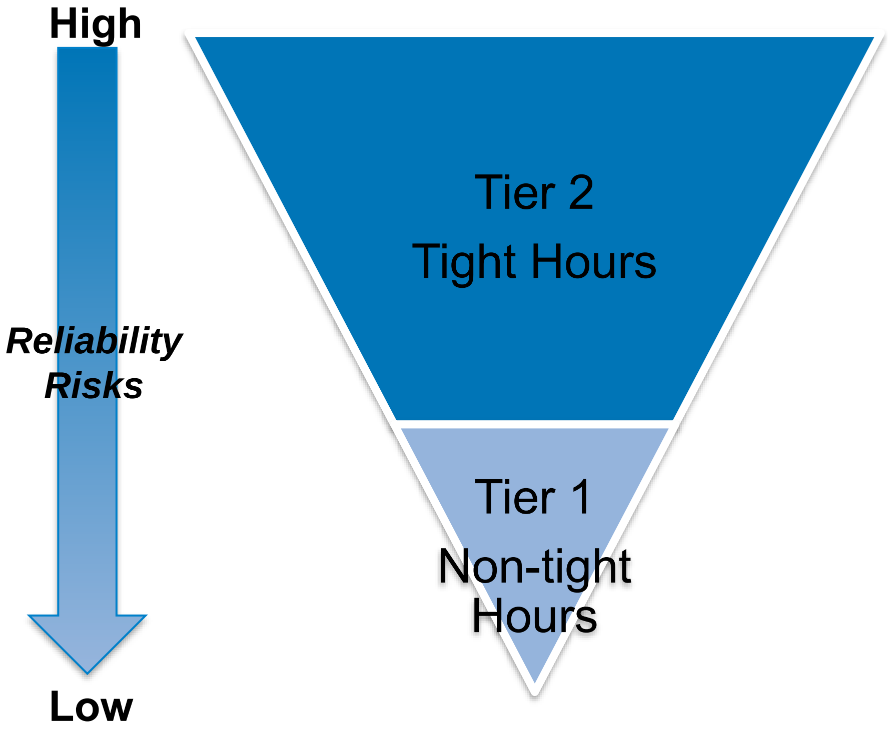
- RA hours are defined as tight margin hours and emergency hours over three historical planning years
  - Margin (%) = online margin + offline margin (24-hour lead time) / RT load
  - For the analysis presented tight margin hours are selected using the tightest 3% of hours across each season in each year, for Central+North and South separately

Sample Calculation

	Central + North						South				
Planning year	**Summer**	**Fall**	**Winter**	**Spring**	**Total**		**Summer**	**Fall**	**Winter**	**Spring**	**Total**
2017-2018	66	66	64	117	**313**		66	67	87	111	**331**
2018-2019	73	65	65	66	**269**		79	67	64	73	**283**
2019-2020	66	65	65	66	**262**		79	65	65	66	**275**
Total	**205**	**196**	**194**	**249**			**224**	**199**	**216**	**250**	

1 Detailed hourly margin data and MaxGen indicators are posted with workshop materials.
2 RT Offer uses EmergencyMax ranges. LMRs and EDRs are excluded. Resources offline with lead time of 24 hours or less are included.

All Hour Availability - MISO proposes a two-tiered weighting approach to reflect general availability while emphasizing availability during times of need



- A tiered weighting accreditation structure will
  - Reflect general availability across the year by counting non-tight hours in accreditation
  - Emphasize availability during times of need by applying higher weighting to tight condition hours
  - Provide a level of stability to inform better resource planning
- Tier 2 includes MaxGen hours overlaying with the top 3% of tightest hours across each season while Tier 1 including all the remaining hours across each season

The diagram is for illustrative purposes only and represents impact to accreditation

MISO's revised accreditation proposal reflects findings from impact analysis and stakeholder discussion

Design Elements		Proposal presented at Feb RASC	Revised Proposal with a two-tiered Weighting structure
Hour Selection	Top X% of tightest margin hours	Top 5% of hours across the year	Tier 1: all hours excluding tight hours in Tier 2 Tier 2: Max Gen hours supplemented with top 3% of tight margin hours
	Max Gen hours	YES	YES
	Regionality (N+C/S) (tight margin and max gen hours)	NO	YES
	Leadtime for offline units (tight margin calc)	24 hours	24 hours
Accreditation Calculation	Annual vs Seasonal	Seasonal	Seasonal
	Tiered Weighting	N/A	Tier 1 20%; Tier 2 80% [1]
	Leadtime for offline units	NO	24 hours
	RT offer considered	Emergency Max	Tier 1 EcoMax; Tier 2 Emergency Max
Planned Outage Exemption	RAN Phase I Enhancement	NO	YES
LOLE modeling	Planned outage modeling	Optimal	Flexible as discussed at May RASC

[1] Weighting factors are indicative and subject to further refinement, 20/80 assigns heavier weighting towards tight condition hours to better incentivize availability during times of need

MISO

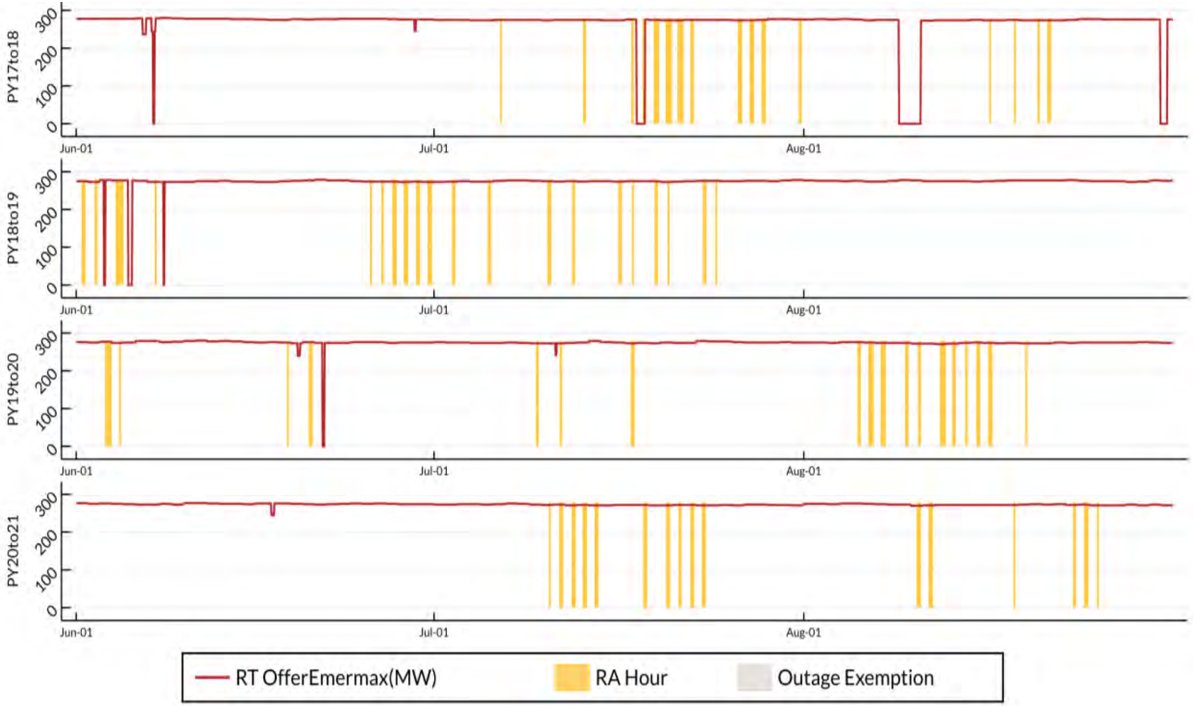
Seasonal PRMR adjustment using a conversion ratio preserves surplus supply

Sample Calculation

Seasonal Conversion of Requirement (MW)		
Seasonal Coincident Peak Forecast	122,398	A
Seasonal Requirement (UCAP)	131,088	B = A * 1.071
Seasonal Thermal UCAP	116,632	C
Seasonal Non-Thermal UCAP	24,678	D
Total Seasonal UCAP	141,310	E = C + D
Seasonal UCAP Surplus/Shortall	**10,222 (7.8% of req)**	**F = E - B**
Seasonal Thermal Accredited MW	108,039	G
Seasonal Conversion Ratio[1]	0.9263	H = G / C
Adjusted Seasonal Requirement	121,430	I = B * H
Seasonal Non-Thermal Accredited MW	22,860	J = D * H
Total Seasonal Accredited MW	130,899	K = G + J
Seasonal Surplus/Shortfall	**9,469 (7.8% of req)**	**L = K - I**

[1]Thermal resources not within the LOLE model or without Real-Time offers were excluded from conversion ratio

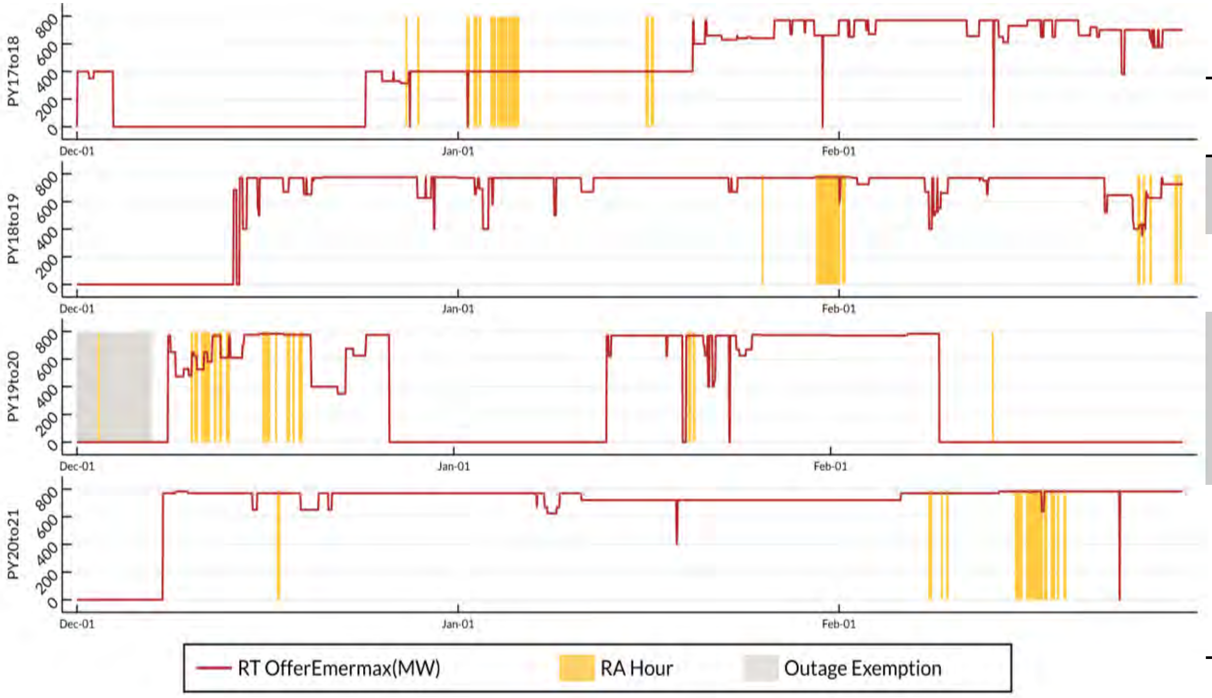
Resources that tend to offer their full availability and don't miss tight hours receive full credit



Season	Winter	Summer*
ICAP	279	276
UCAP	272	260
Accredited Capacity PY17-20**	274	273
Accredited Capacity PY18-21**	277	273

Summer* means June–August, not September
PY17-20** Proposed accreditation based on offers in 3 previous seasons

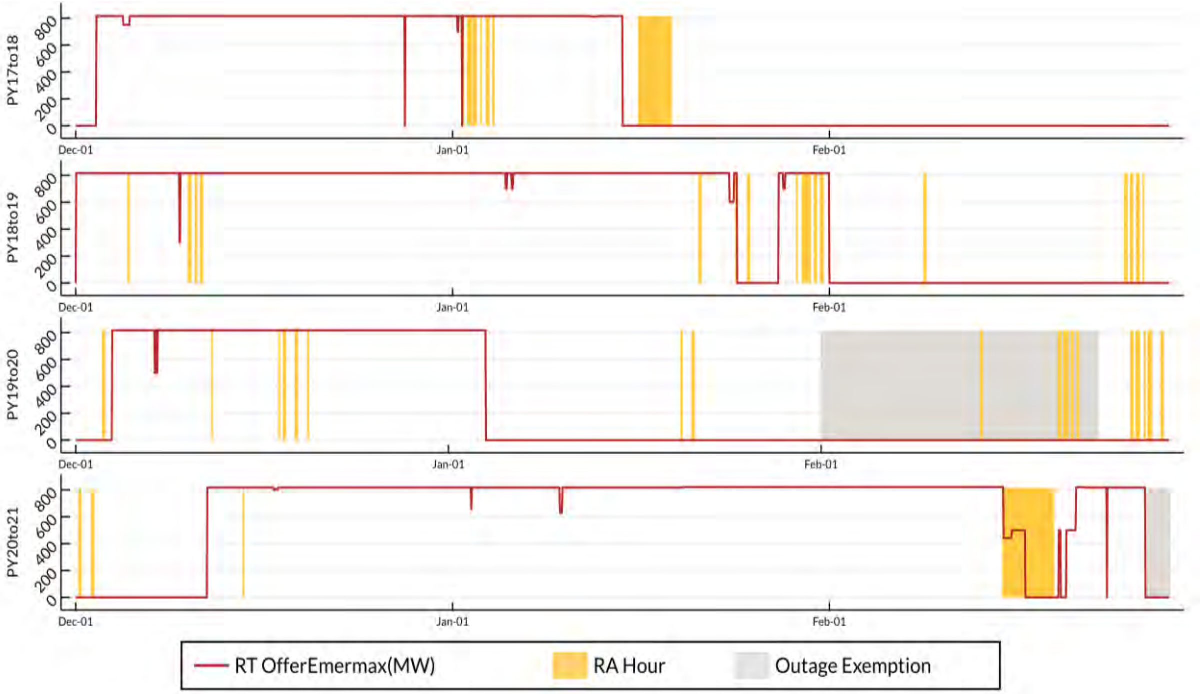
The revised proposal recognizes coordinated outages as exempt and values availability when it counts the most



Season	Winter	Summer*
ICAP	774	771
UCAP	728	705
Accredited Capacity PY17-20**	467	575
Accredited Capacity PY18-21**	680	590

Summer* means June–August, not September
PY17-20** Proposed accreditation based on offers in 3 previous seasons

The proposal also recognizes when resources are frequently unavailable during times of need without sufficient coordination to receive an outage exemption



Season	Winter	Summer*
ICAP	814	815
UCAP	757	777
Accredited Capacity PY17-20**	520	787
Accredited Capacity PY18-21**	348	746

Summer* means June–August, not September
PY17-20** Proposed accreditation based on offers in 3 previous seasons

MISO

Next Steps

Monthly view of discussions, impact reviews and additional opportunities to provide input

Workstream	May	June	July - August
LOLE requirements	Seasonal LOLE targets, zonal CILs, conversion ratio, consider state & LSE resource planning processes	Zonal CEL/LCRs; Review and refine seasonal PRMR targets	Refine requirement calculations
Resource accreditation	Lead time cutoffs for offline units, incentives for coordinated outage planning	System and Zonal accreditation impacts, seasonal outage limits	Review zonal positions and effectiveness of availability incentives to fine tune design
PRA specifics	Impact to outage rules and CONE settlement, pace of change [deferred to June]	Transition needs, potential for prompt, sequential	Finalize detailed design elements and implementation
DA performance obligation	Capacity market power protections [deferred to June]	Evaluate physical withholding exemption	Review and refine seasonal obligations and compliance monitoring
Tariff filing	Discuss outline, filing strategy, key arguments and evidence [also June]	Post available draft tariff language	Post and review needed tariff changes
Input and impacts	Review and comment on zonal impacts and exemptions for prudent planned outages	Review and comment on changes to supply and demand in each zone	Review and comment on conceptual design and draft tariff language

CONE = Cost of New Entry | LRZ = Load Resource Zone | LSE = Load Serving Entity

Next Steps

- Continue conceptual design phase of the proposed RA construct changes and analysis to develop and refine detailed design elements
- Conduct May RAN workshop to review revised RA construct proposal and detailed analysis results

Issue ID	Associated IDs	Project Name	Proposed By	Current Phase	Impact	Priority	2021				2022				2023				2024			
							1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q
Resource Adequacy Subcommittee (RASC)																						
RASC 10	2018-5 IR095 IR096	**Resource Accreditation** Sub Issue of IR025 - (RAN)	Stakeholders, MISO, IMM	Concept Design	MECT	High	C	C	F	F	B	B	B	I	I	V						
RASC 11	2014-5 IR094	**Resource Adequacy Construct** Sub Issue of IR025 - (RAN)	Stakeholders, MISO	Concept Design	MECT	High	C	C	F	F	B	B	B	I	I	V						
RASC 12		**Reliability Requirements & Metrics** Sub Issue of IR025 - (RAN)	MISO	Concept Design	MECT, MSE	High	C	C	F	F	B	B	B	I	I	V						

FRAME	EVALUATE	FERC FILING	BUILD	IMPLEMENT	VALIDATE

MISO

Contact Information

Scott Wright
swright@misoenergy.org

Appendix

Overview of Resource Adequacy construct design decisions developed and under development

	LOLE Analysis Establish RA requirements	Resource Accreditation Register resources and qualification	Planning Resource Auction Demonstrate compliance	DA Performance Obligation Ensure availability
Developed	4 seasonal requirements Planning Reserve Margin (PRM) and Local Clearing Requirements(LCRs)	Seasonal accredited values	4 independent seasonal auctions at one time	Seasonal must offer requirements for cleared seasons
Under Development	• Season definition • Seasonal risk target allocation • Seasonal Capacity Import Limit (CIL) and Capacity Export Limit (CEL)	• Accreditation based on resource availability • Registration and qualification • Seasonal Wind Effective Load Carrying Capability (ELCC)	• Seasonal Auction participation eligibility • Capacity replacement • Minimum capacity requirement	• Cost of New Entry (CONE) calculation and settlement • Capacity market power protections

RA construct changes decisions developed
Design decisions under development

The conceptual design timeline runs from January to August with targeted FERC filing in September

Qualitative and Quantitative Evaluation of RA construct options

We are here

Conceptual design of proposed RA construct changes

Development of RA construct tariff language

August - December | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **Sept.**

RASC & Evaluation Workshops (8/05 – 12/31)
- Develop criteria for evaluation
- Define scenarios and inputs
- Discuss construct options
- Review evaluation results

RASC (1/06)
- Review *initial* RA construct proposal
- Initiate Conceptual Design phase

RASC (2/03)
- Review RA construct proposal
- Discuss conceptual design scope

RASC (3/10)
- Review initial RA construct design options

RASC (4/14)
- Review Stakeholder feedback and motion on Accreditation proposal

RASC &Workshop (5/12 & 5/21)
- Review revised proposal and design options

RASC (6/09)
- Review RA construct design

RASC (7/07)
- Review RA construct design
- Initial draft tariff language

RASC (8/04)
- Review final RA construct design
- Review revised draft tariff language

RASC (9/01)
- Review final tariff language

Note: green indicates opportunity for formal feedback

Conceptual design workshop

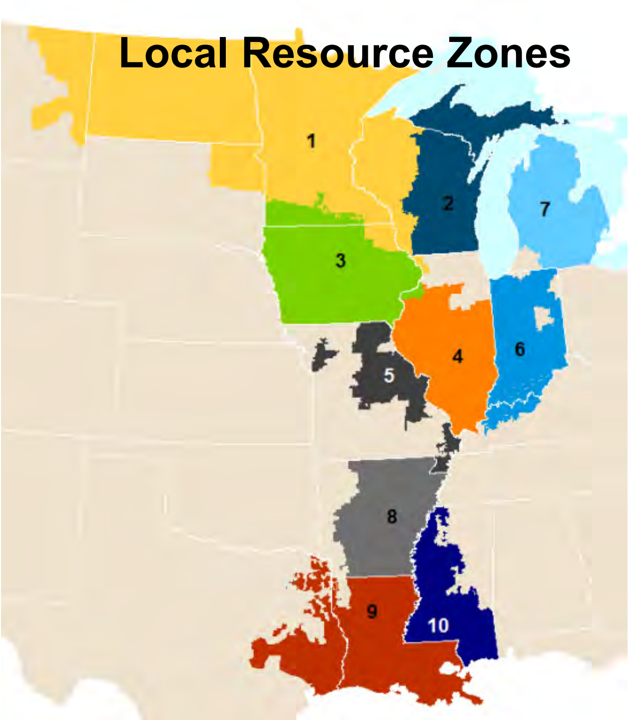
MISO conducted seasonal transfer limit analyses to assess seasonality of CIL using existing methodology in BPM-011

Models	Summer	Winter	Spring	Fall
Powerflow Model	MISO20 Series 2021 Summer Peak (effective date 7/15/2021)	MISO20 Series 2021 Winter Peak (effective date 1/15/2021)	MISO20 Series 2021 Spring Peak (effective date 4/15/2021)	MISO21 Series 2021 Fall Peak (effective date 10/15/2021)
Generation Dispatch	• Local Balancing Area (LBA) NR dispatch • Wind unit output = capacity credit • Solar unit output = 50% • Attachment Y approved retirements and suspensions effective during PY 2021-22 are modeled offline	• Local Balancing Area (LBA) NR dispatch • Wind unit output = 40% capacity factor • Solar unit output = 0% • Attachment Y approved retirements and suspensions effective during PY 2021-22 are modeled offline	• Local Balancing Area (LBA) NR dispatch • Wind unit output = 28.5% capacity factor • Solar unit output = 0% • Attachment Y approved retirements and suspensions effective during PY 2021-22 are modeled offline	• Local Balancing Area (LBA) NR dispatch • Wind unit output = 28.5% capacity factor • Solar unit output = 31% • Attachment Y approved retirements and suspensions effective during PY 2021-22 are modeled offline
Projects Included	MTEP20 Appendix A and Targeted A	MTEP20 Appendix A and Targeted A	MTEP20 Appendix A and Targeted A	MTEP21 Appendix A and Targeted A
Monitored and Contingencies	PY21-22 annual transfer limit input files	PY21-22 annual transfer limit input files with winter model updates	PY21-22 annual transfer limit input files with Spring model updates	PY21-22 annual transfer limit input files with Fall model updates

MISO proposes to conduct seasonal transfer limit analysis to reflect seasonality of CIL/CEL values

Sample Calculation

Zone	PY21-22 ZIA (MW)	Winter ZIA	Spring ZIA	Fall ZIA
1	5,059	4,120	2,839	4,359
2	3,599	3,526	3,952	4,383
3	4,556	6,355	6,080	5,198
4	5,141	7,343	5,418	5,495
5	4,384	4,712	4,227	5,313
6	6,738	5,834	6,118	6,237
7	4,888	4,925	5,383	6,778
8	5,155	5,340	4,598	4,460
9	3,284	3,427	4,769	5,017
10	3,283	1,100	2,268	2,508



- Large variations occur in zonal CILs across seasons mainly driven by topology and generation dispatch

ZIA – Zonal Import Ability

MISO proposes to adjust requirements on seasonal basis using a conversion ratio to better align accreditation and requirements

UCAP Calculation in LOLE

- Calculate thermal resource UCAP values for each season by removing external resources, Wind/Solar and Load Modifying Resources (LMRs)
- Use sub-annual Loss of Load Expectation (LOLE) modeling assumptions to determine seasonal resource adequacy requirements

New Accreditation Calculation based on offers

- Calculate thermal resource availability for each season by averaging the availability of the RT offers over three-year period with a two-tiered weighting structure

Conversion Ratio from LOLE model to accreditation

- Determine MISO system wide and zonal level conversion ratios by dividing total thermal offer based accredited values by total UCAP values
- Adjust PRMR and LCR requirements by multiplying requirements derived from LOLE analysis by corresponding conversion ratios

Seasonal accreditation calculation based on RT offers Example

- Seasonal accredited value is determined by averaging all hours in Tier 1 weighted by 20% and adding it to the average of the RA hours in Tier 2 weighted at 80% [1]
  - Tier 1 average = 100 MW; Tier 2 average = 120 MW
  - Accredited Value = 100 MW * 0.2 + 120 MW * 0.8 = 116 MW

[1] Weighting factors are indicative and subject to further refinement, 20/80 assigns heavier weighting towards tight condition hours to better incentivize availability during the times of need

RAN phase I has enabled better outage scheduling processes as the basis for further improvements

- Planned outages and derates that overlap MaxGens are exempted from accreditation penalties if
  - The outage request is made at least 120 days in advance or
  - Requested 14 to 119 days in advance with positive Maintenance Margin for the duration of the outage or
  - Outages are moved per MISO request
- The RAN Phase 1 accreditation penalty applies to non-exempt planned outages and derates that overlap MaxGens (alerts, warning & events) by treating just the overlapping days as forced outages (1 day out of 1,095 in a 3-year accreditation period)
- Improvements made on outage coordination processes through RAN Phase I created a stepping stone for further enhancements

INTEGRATED MARKETPLACE AND OPERATIONS UPDATE

BRUCE REW, PE

SENRIO VICE PRESIDENT, OPERATIONS

SPP INTEGRATED MARKETPLACE UPDATE

- Marketplace Operational Highlights
- Historical Load and Wind Trends
- Marketplace Highlights and Information
- Enhancements implemented and under development

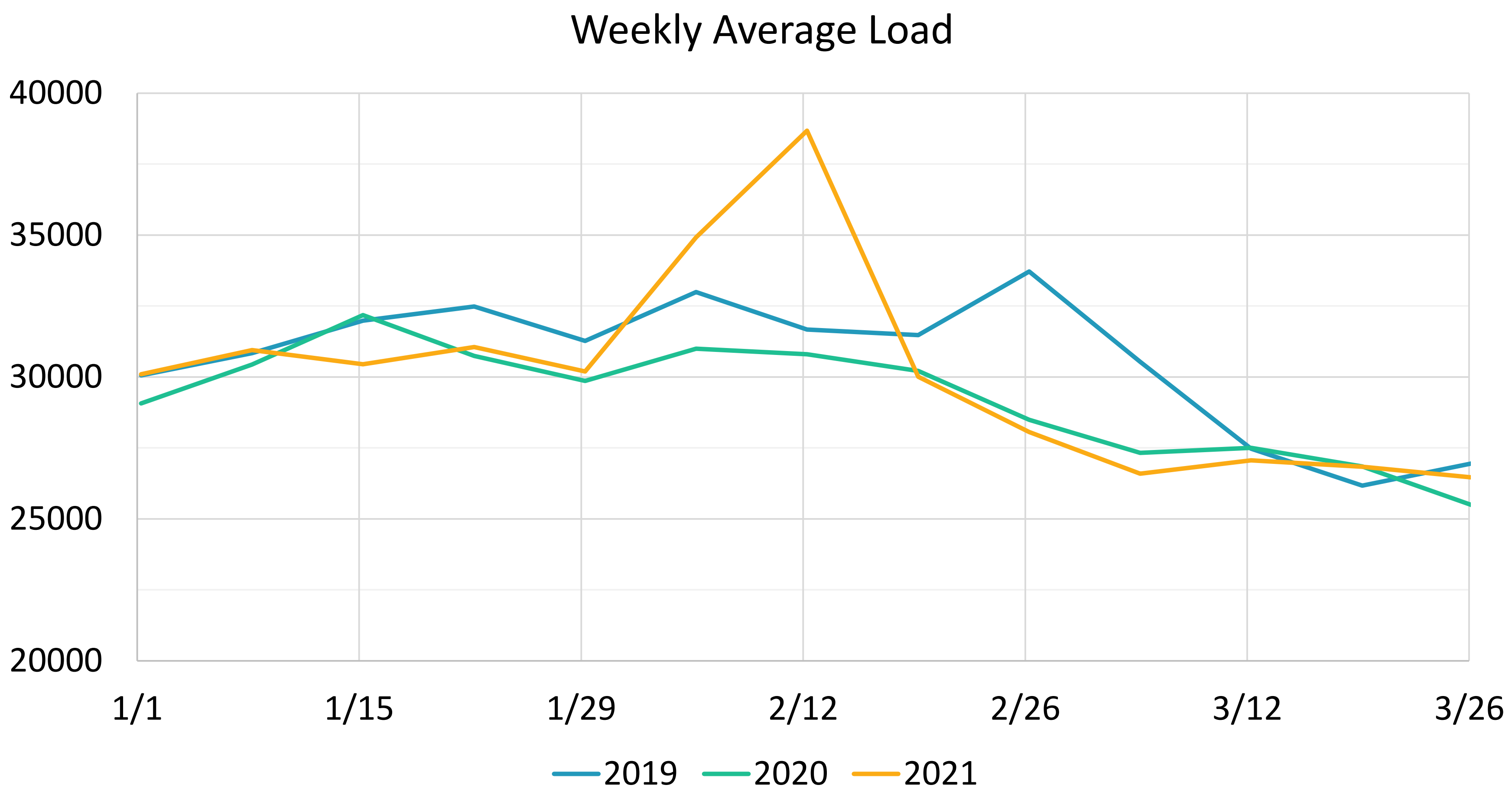
New Records set during the quarter!

- New Historical Max Winter Load peak during the quarter
  - Total MW peak of 43,661 MW on 02/15 at 08:58
- New Historical Max Wind Penetration (as % of BA Load) peak during the quarter
  - Total peak of 81.85% on 03/29 at 04:33
- New Historical Max Wind generation output peak during the quarter
  - Total MW peak of 21,133 MW on 03/29 at 07:35
- New Historical Renewable Penetration peak during the quarter
  - Total peak of 84.2% on 03/29 at 04:33
- New Renewable Total (Wind+Solar+Hydro+Waste) peak during the quarter
  - Total MW peak of 22,685 MW on 03/29 at 07:35

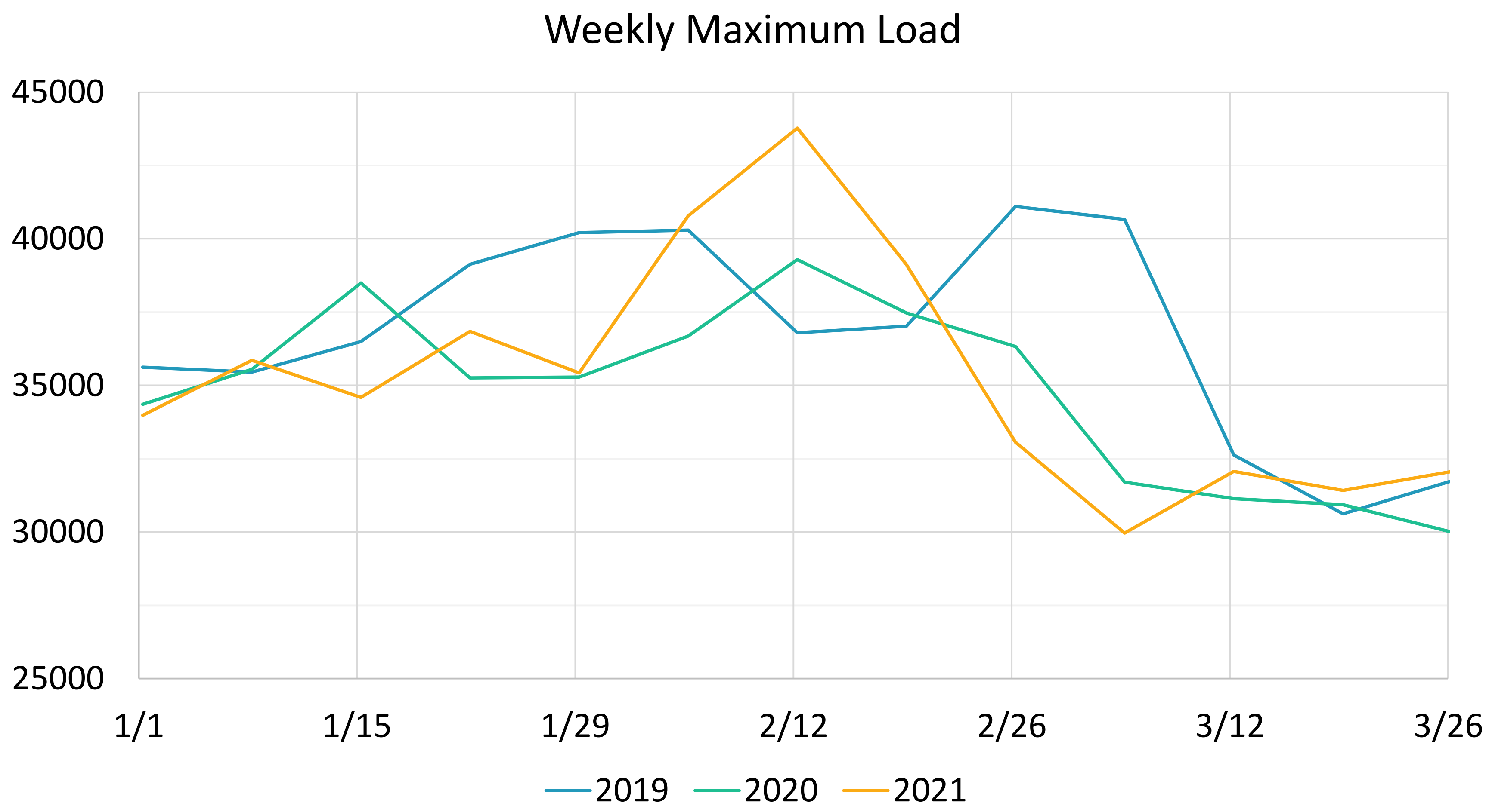
Marketplace Operational Highlights

- Forecasting Accuracy Error averages for the quarter
  - Load forecast error was 2.05%, compared to 1.68% in Q1 2020
  - Wind forecast error was 4.60%, compared to 5.20% in Q1 2020
  - Solar forecast error was 4.88%, compared to 5.63% in Q1 2020
- Currently 27.61 GW of wind registered in the market
- Significant icing event affected Wind generation on Monday, February 8
  - Operations issued a Resource Alert on the morning of the 8th due to wind uncertainty and cold weather
  - Forecast for max loss of 2 GW but experienced loss of over 5 GW of wind
  - Freezing rain and freezing fog contributed to wind loss
- Winter Storm Uri impacts (February 13-17)
  - Set new Winter Peak Load
  - Load shed of 1.5% for less than hour on February 15
  - Load shed of up to 6.5% during a 3 hour period on February 16

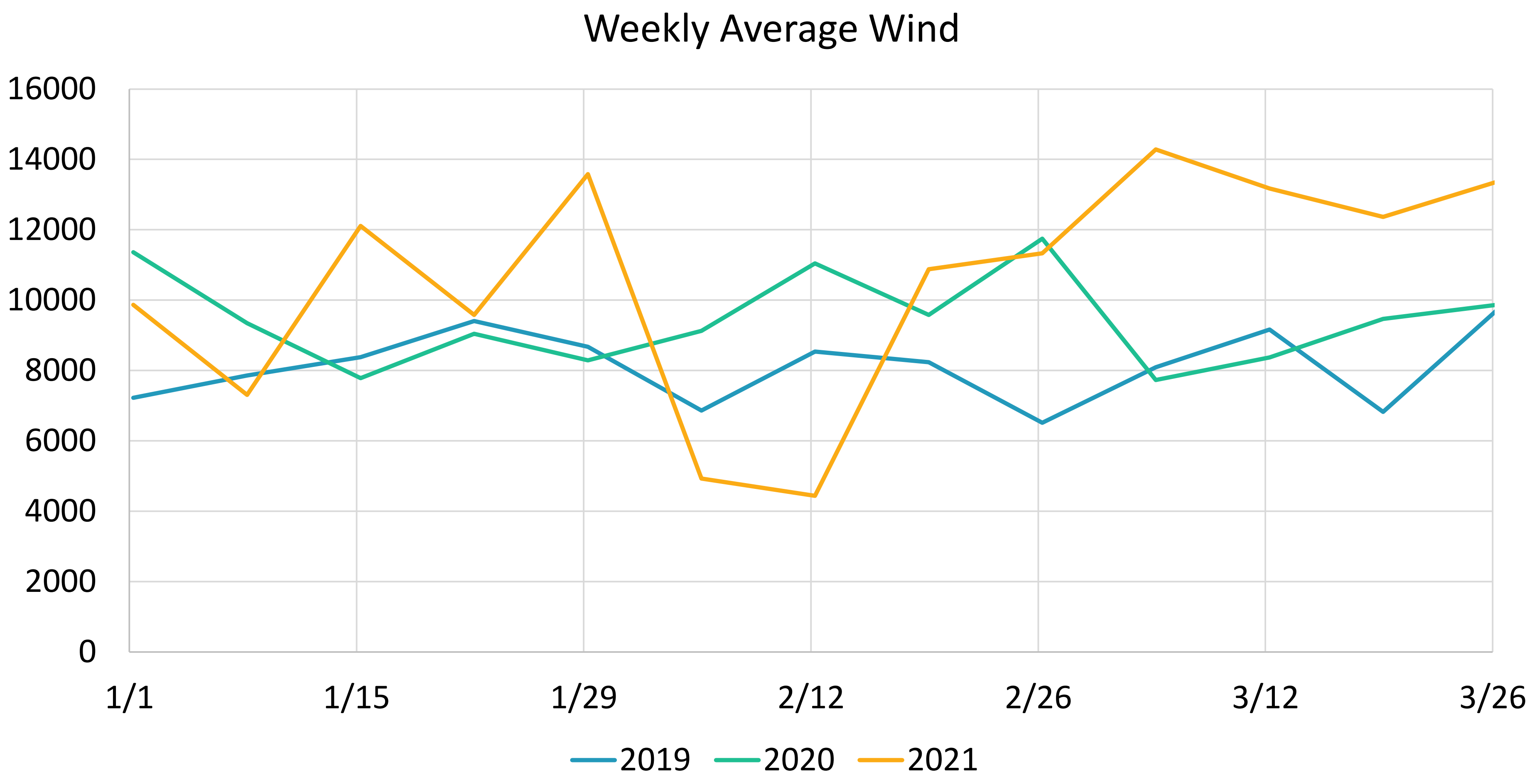
SPP Weekly Average Load profile: January - March (comparing 2019, 2020, 2021 years at same date)



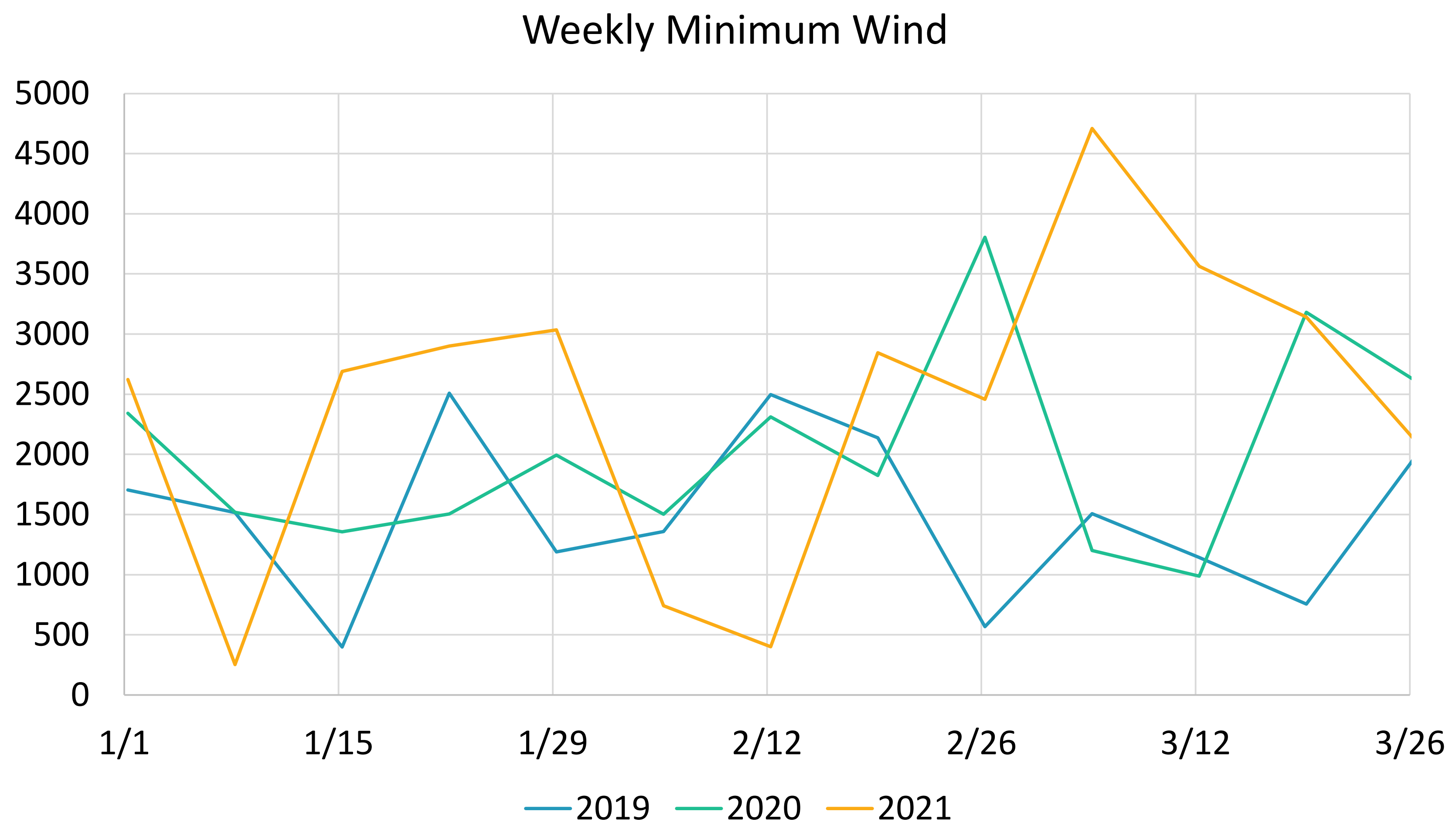
SPP Weekly Maximum Load profile: January - March (comparing 2019, 2020, 2021 years at same date)



SPP Weekly Average Wind profile: January - March (comparing 2019, 2020, 2021 years at same date)



SPP Weekly Minimum Wind profile: January - March (comparing 2019, 2020, 2021 years at same date)



WIND OUTPUT: JAN – MAR 2021

	@ Max Wind Output	@ Min Wind Output
MW Wind	21,133.26 MW	252.32 MW
Time	03/29 @ 07:35:28	01/09 @ 10:06:00
SPP Load	29,109.39 MW	32,867.79 MW
Gen Mix Percent		
Wind	70.5%	0.8%
Coal	14.3%	48.3%
Nat. Gas	7.2%	40.0%
Nuclear	2.7%	6.2%
Hydro	5.1%	4.4%
Other	0.1%	0.2%

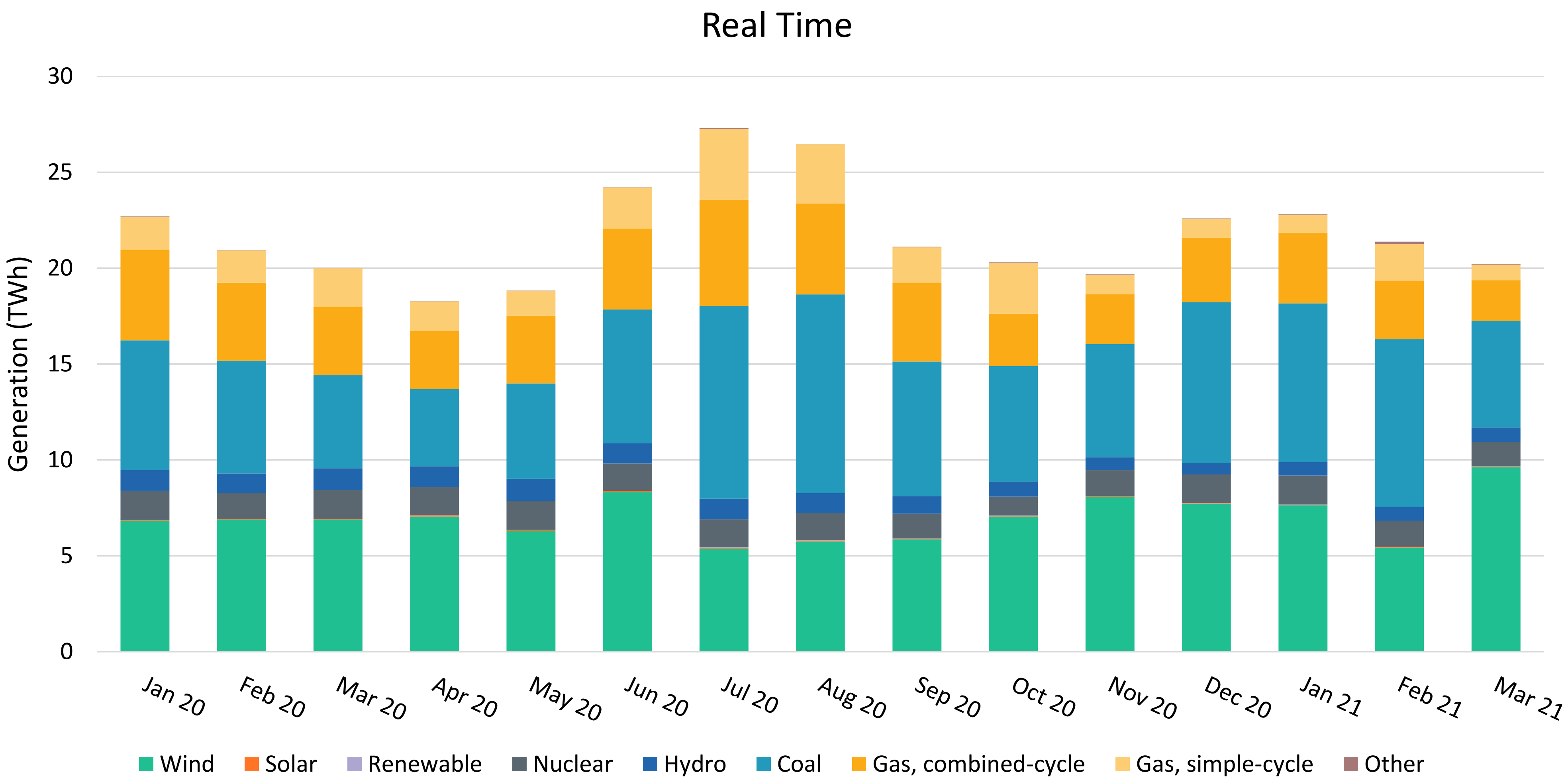
WIND PENETRATION: JAN – MAR 2021

	Max Penetration	Min Penetration
Wind Penetration	81.8% of load	0.77% of load
Time	03/29 @ 04:33:28	01/09 @ 10:06:00
SPP Load	23,901.67 MW	32,867.79 MW
Wind Output	19,563.69 MW	252.32 MW
Gen Mix Percent		
Wind	77.0%	0.8%
Coal	12.2%	48.3%
Nat. Gas	5.2%	40.0%
Nuclear	3.2%	6.2%
Hydro	2.2%	4.4%
Other	0.1%	0.2%

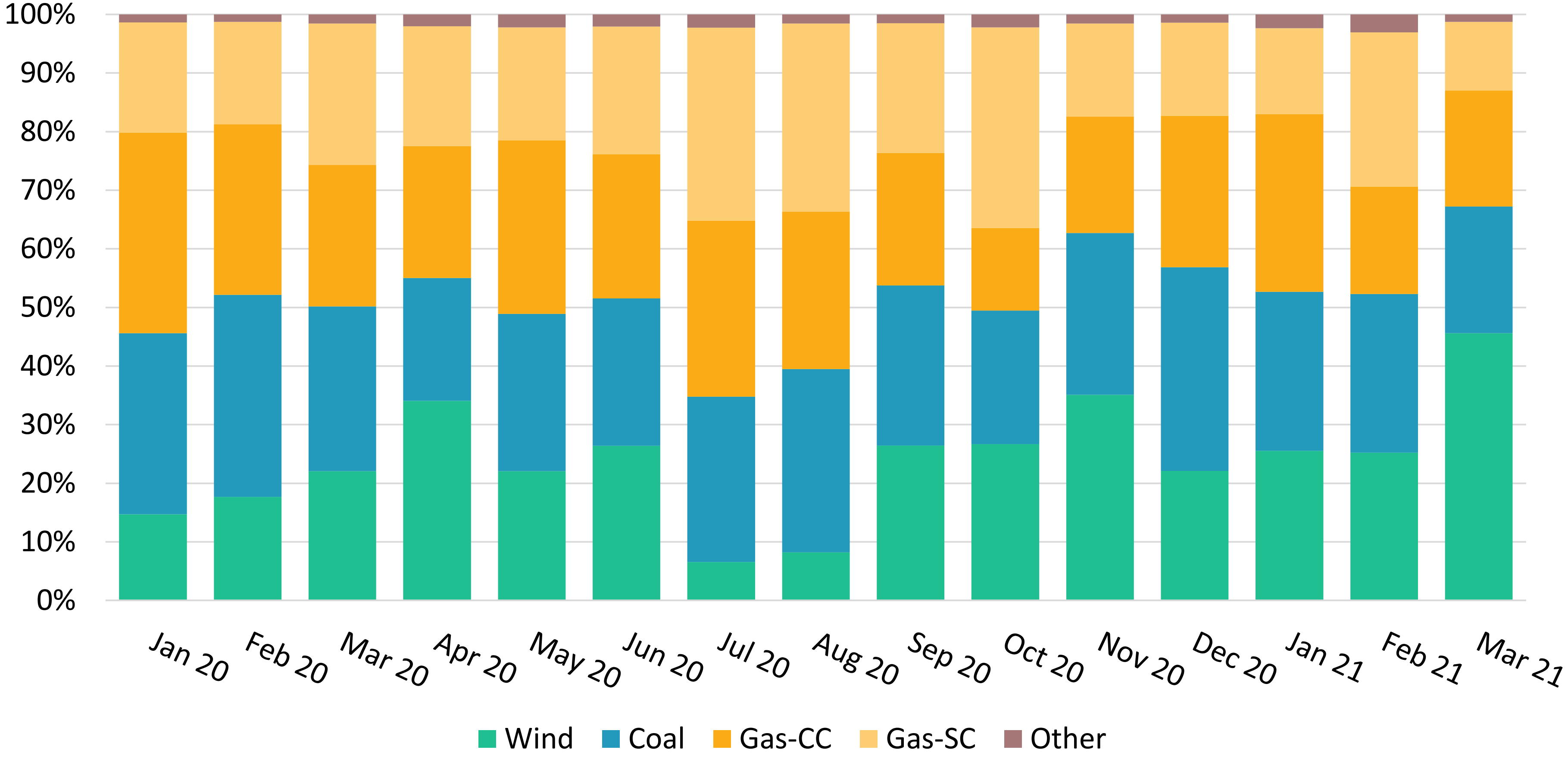
MARKETPLACE OVER LAST 12 MONTHS

- 270 Market Participants
  - 172 financial only and 98 asset owning
- SPP BA has successfully maintained NERC control performance standards (BAAL & CPS)
- High System availability
  - Day-Ahead Market results have posted 99.29% on time in past 12 months
  - Real-Time Balancing Market has successfully solved 99.9% of all intervals in the past 12 months

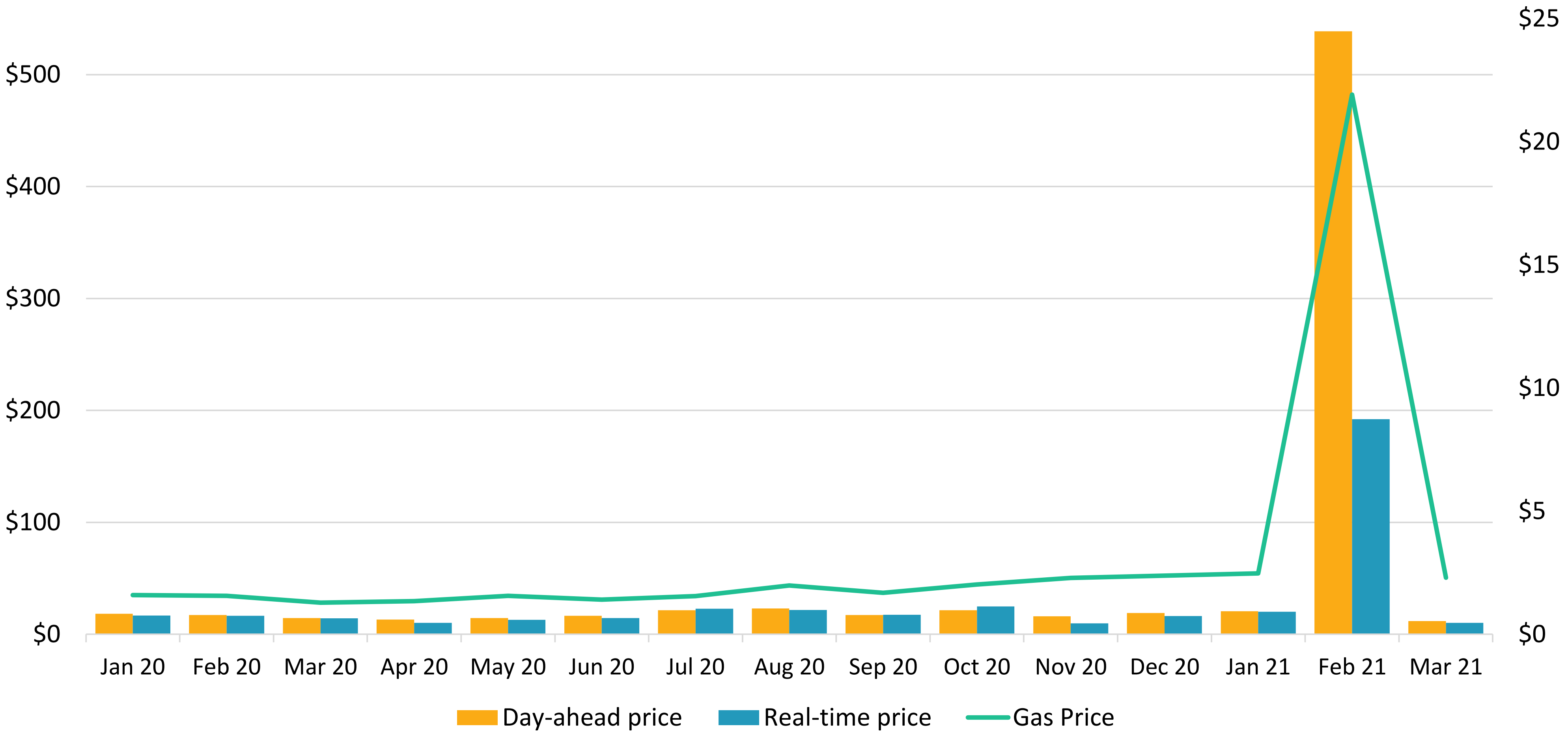
DISPATCH BY FUEL TYPE



FUEL ON THE MARGIN IN REAL-TIME

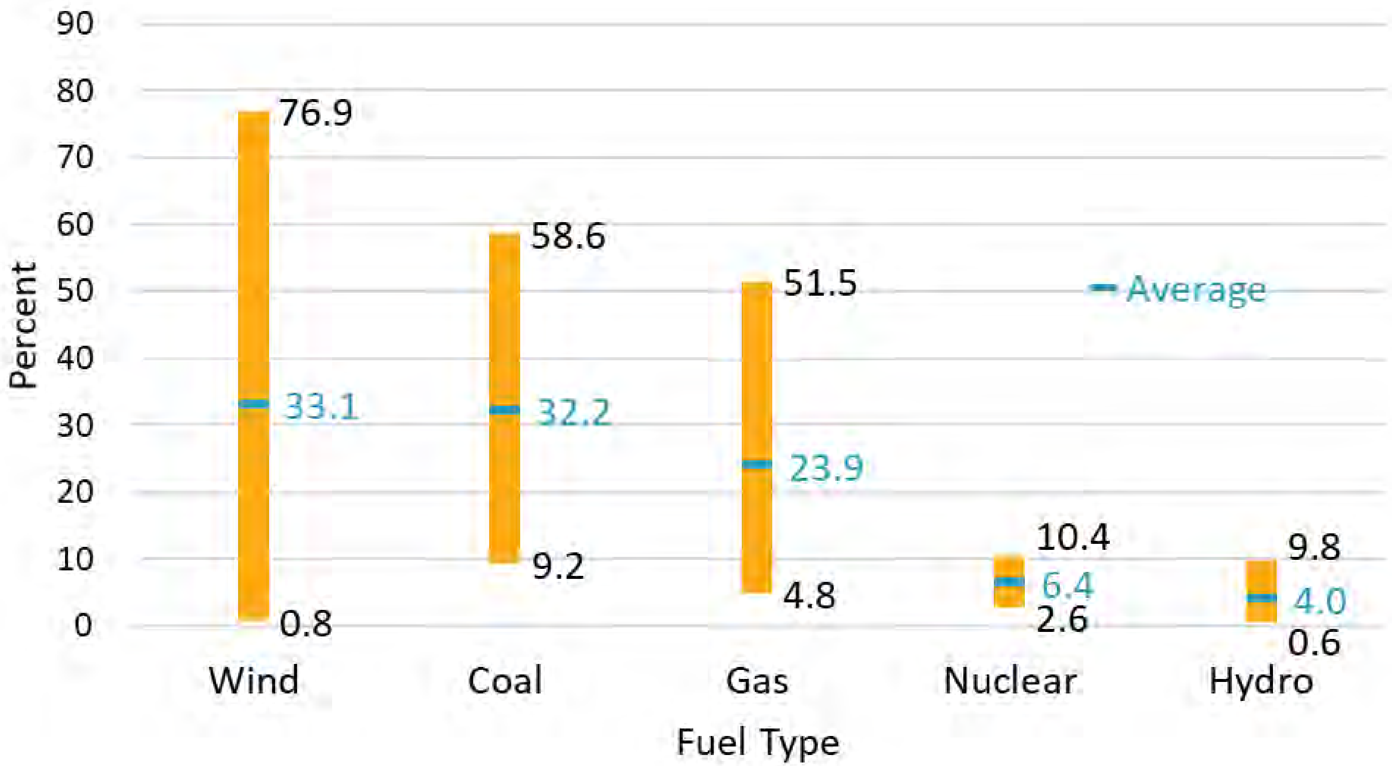


REAL-TIME VERSUS DAY-AHEAD PRICING



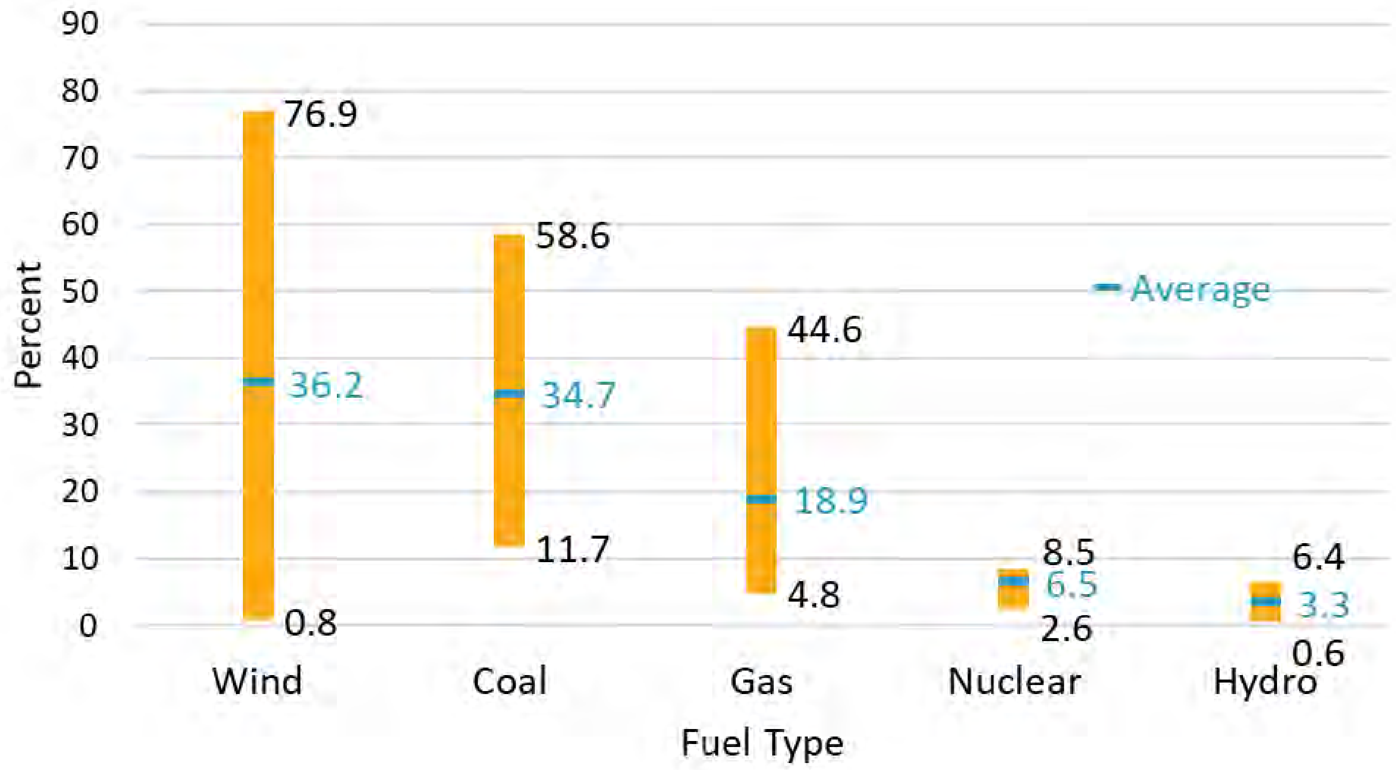
* These prices are average SPP trading hub LMPs

Min and Max Percent of Generation Mix Per Fuel Type - Last 12 Months



*RTBM 5-minute average

Min and Max Percent of Generation Mix Per Fuel Type – Q1 2021



*RTBM 5-minute average

INTEGRATED MARKETPLACE ENHANCEMENTS TIMELINE

- In-Process and Upcoming work
  - RR323: Order 841 – Compliance ESR;
    - August 5, 2021 effective date
  - RR361: Ramp capability products;
    - November 2021 planned implementation
  - RR288: DVER Dispatch Instruction Rules clean-up
    - Implemented with Ramp project, November 2021
  - RR375/402/420: Fast start
    - May 2022 planned implementation


OUR MISSION:
HELPING OUR MEMBERS WORK TOGETHER TO KEEP THE LIGHTS ON ... TODAY AND IN THE FUTURE.

The Effects of Winter Storm Uri on Natural Gas Utilities

John Gunnells, Manager, State Affairs
Juan Alvarado, Director, Energy Analysis
NARUC Gas Committee Monthly Meeting
April 16th, 2021

American Gas Association

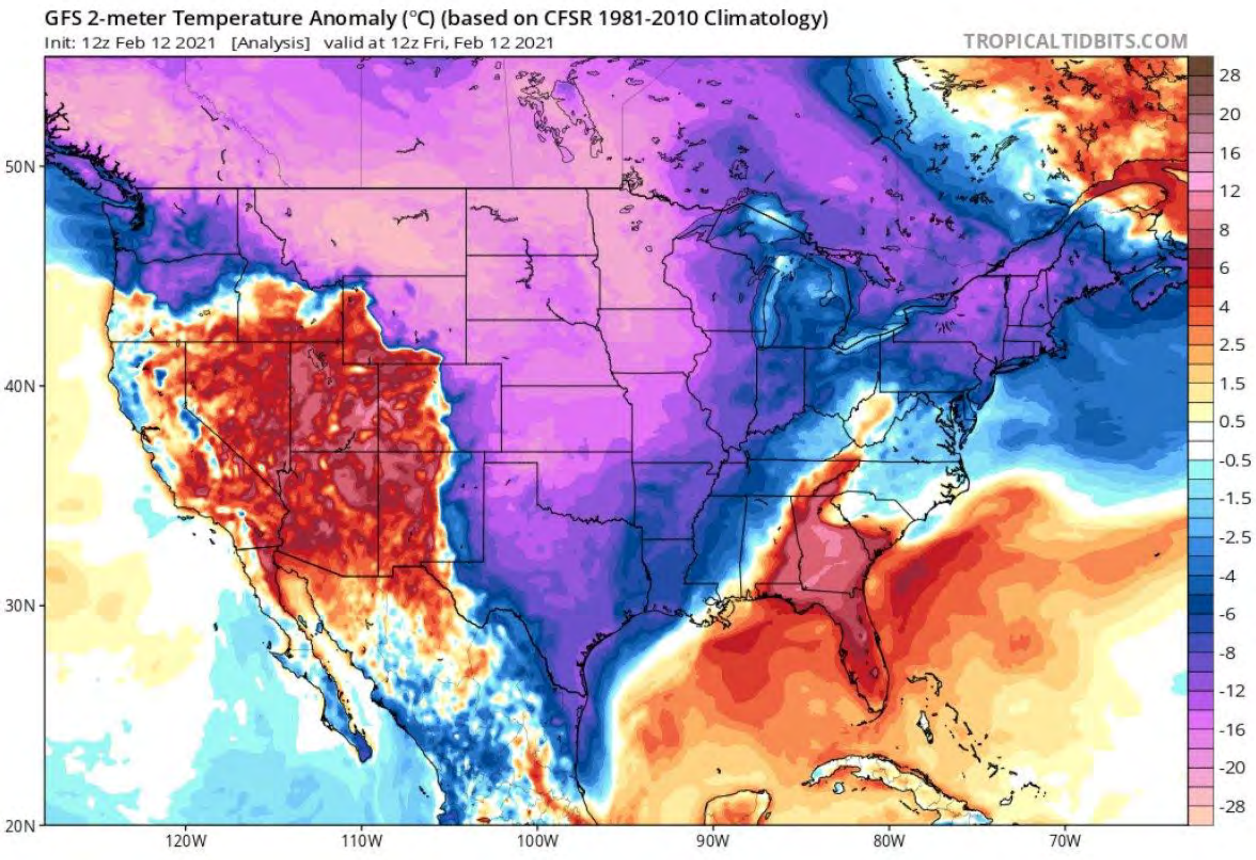
AGA
American Gas Association

The American Gas Association (AGA) represents companies delivering natural gas safely, reliably, and in an environmentally responsible way to help improve the quality of life for their customers every day. AGA's mission is to provide clear value to its membership and serve as the indispensable, leading voice and facilitator on its behalf in promoting the safe, reliable, and efficient delivery of natural gas to homes and businesses across the nation.

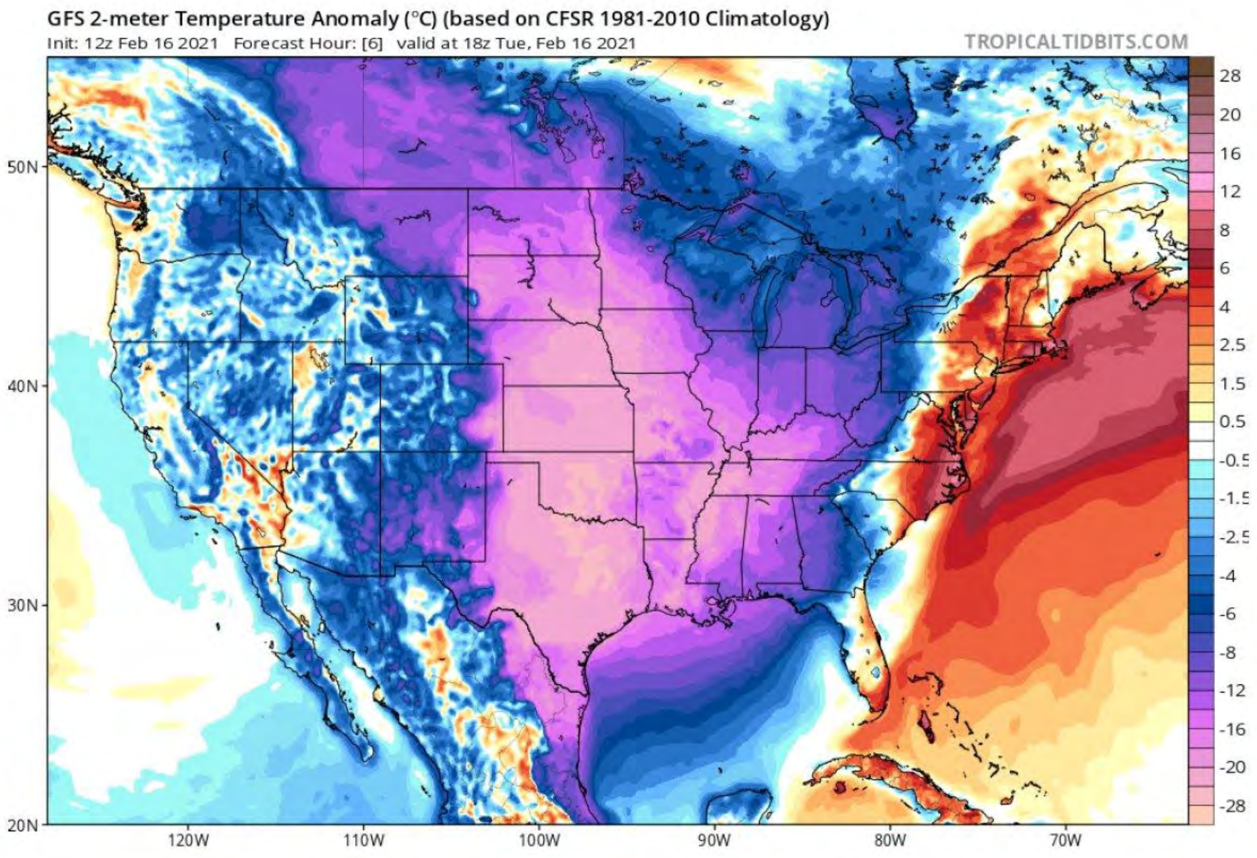
Committed to utilizing America's abundant, domestic, affordable and clean natural gas to help meet the nation's energy and environmental needs.

An arctic air mass led to colder-than-normal conditions in all but six states.

US temperature anomaly map
Friday, Feb. 12

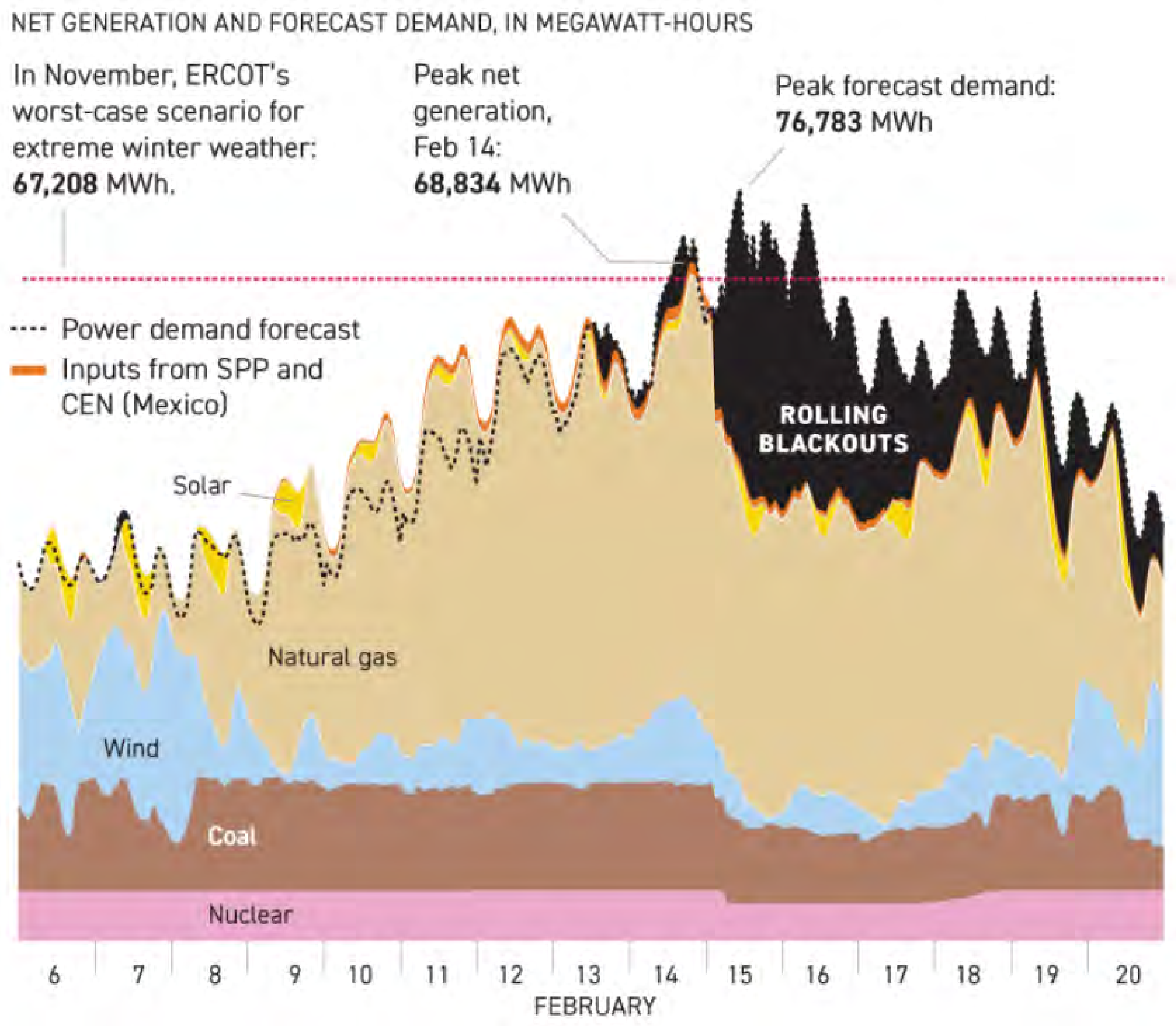


US temperature anomaly map
Tuesday, Feb. 16



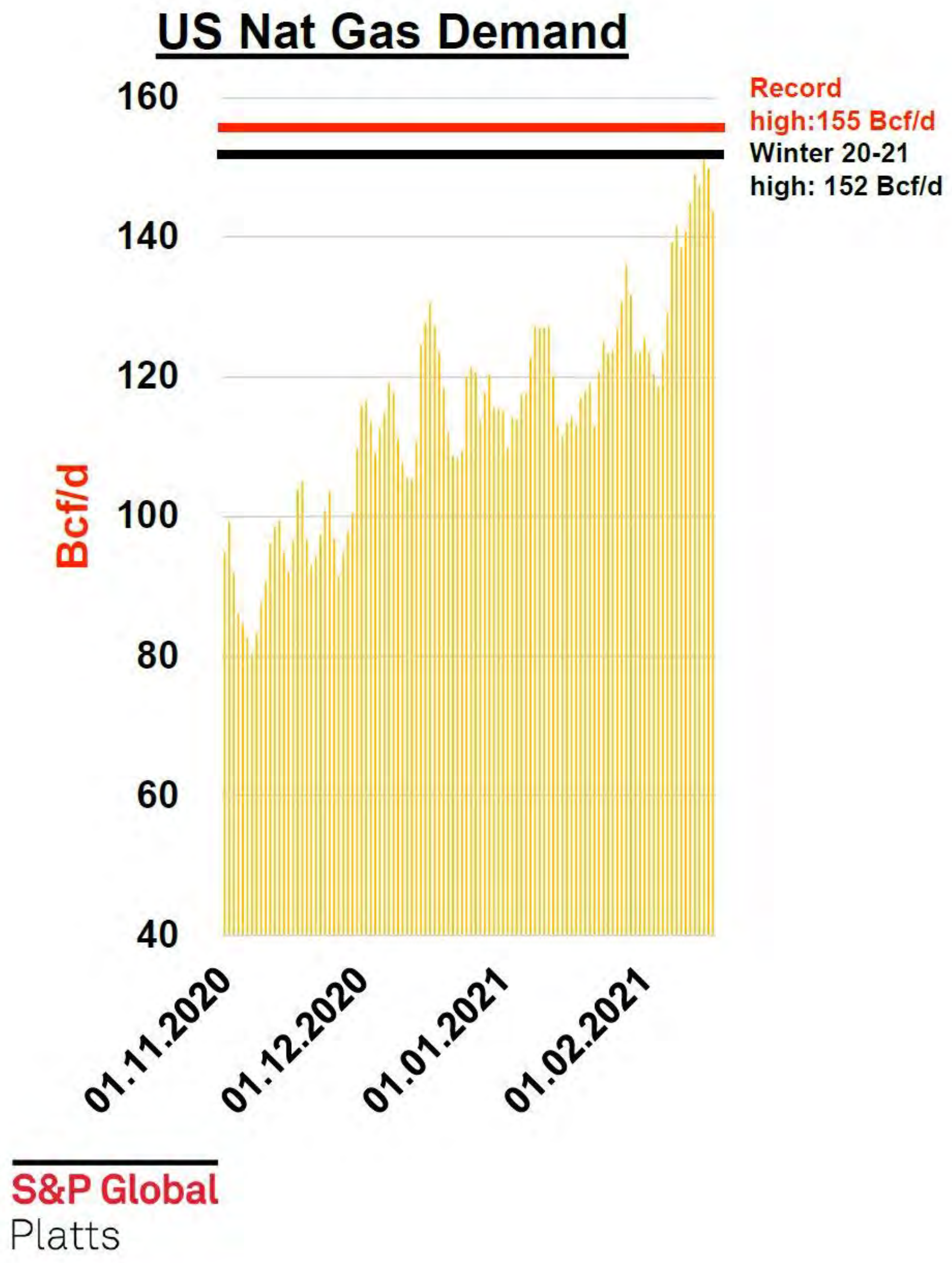
HDD Source: NOAA and Paul Pierson

Source: Tropical Tidbits



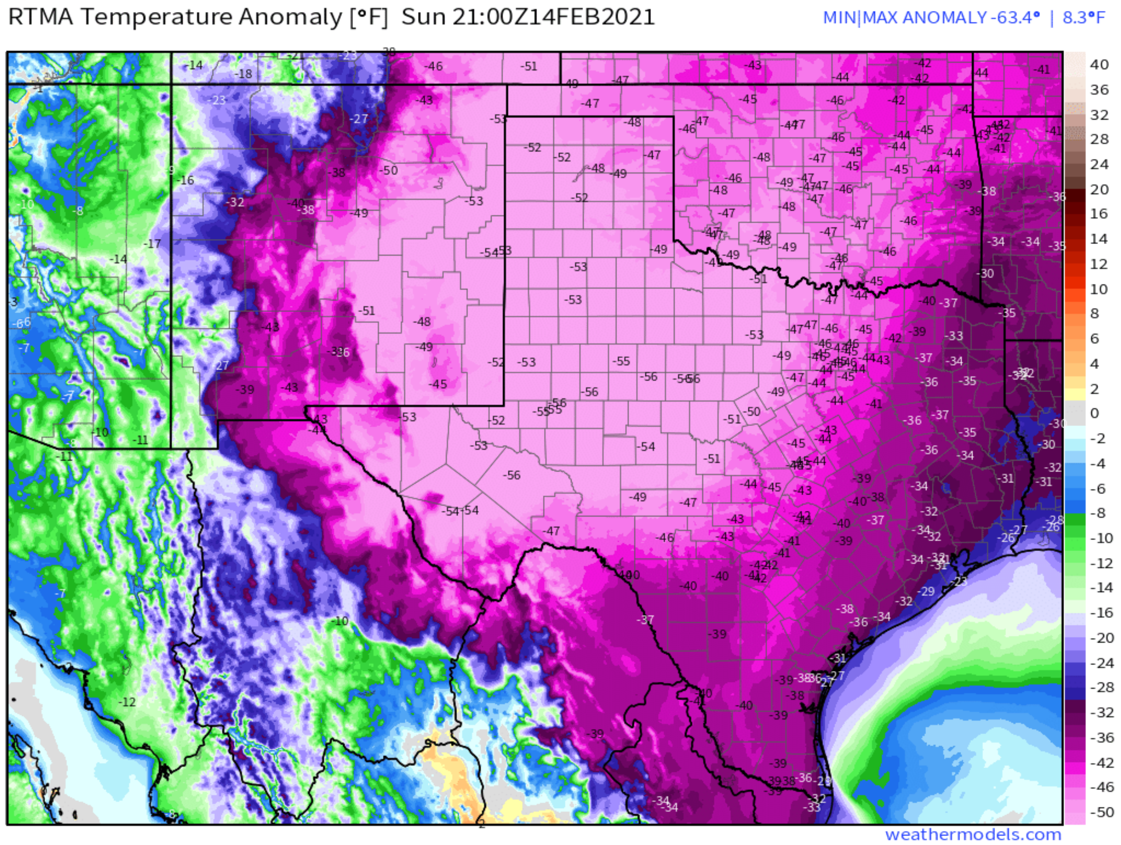
Graphic: Politico

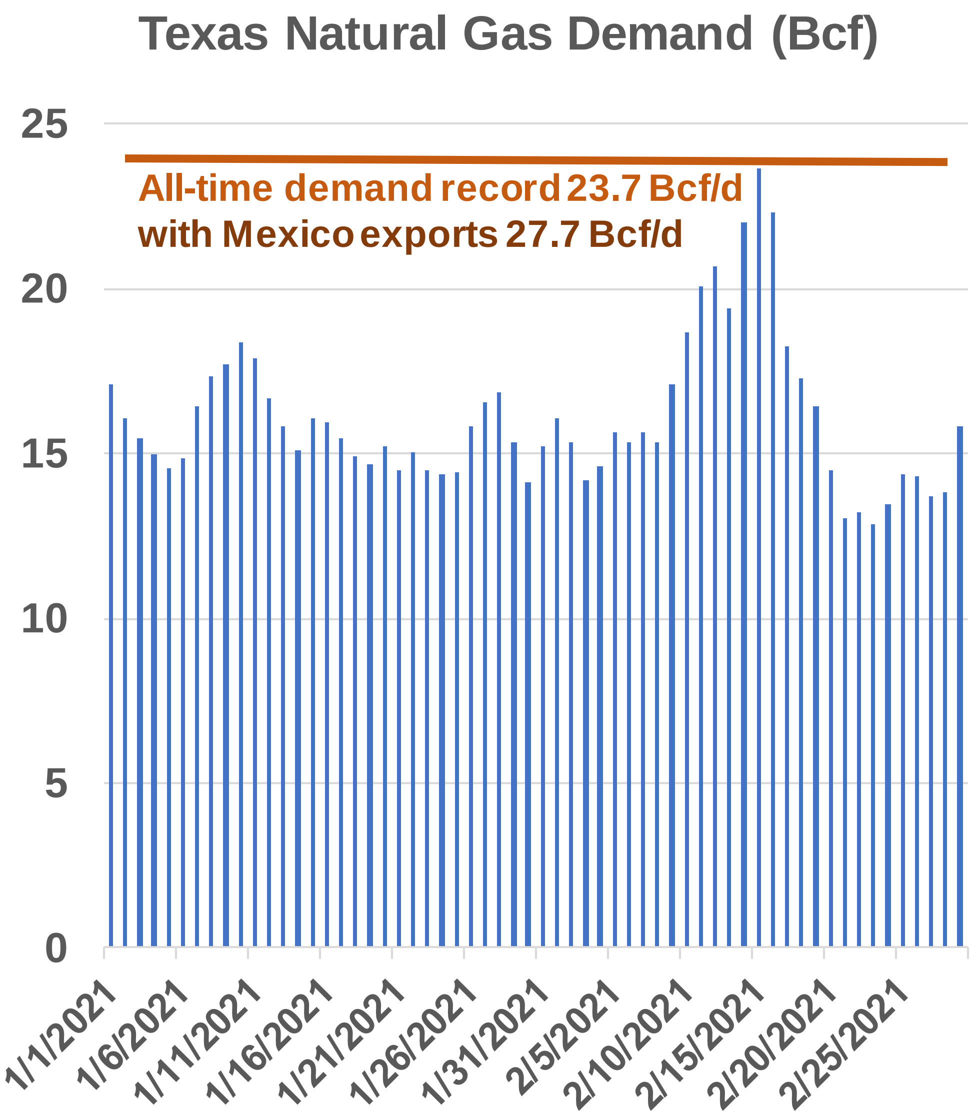
US natural gas demand set a two-day record on February 14 and 15.



Texas set a new demand record for natural gas consumption during the cold event.

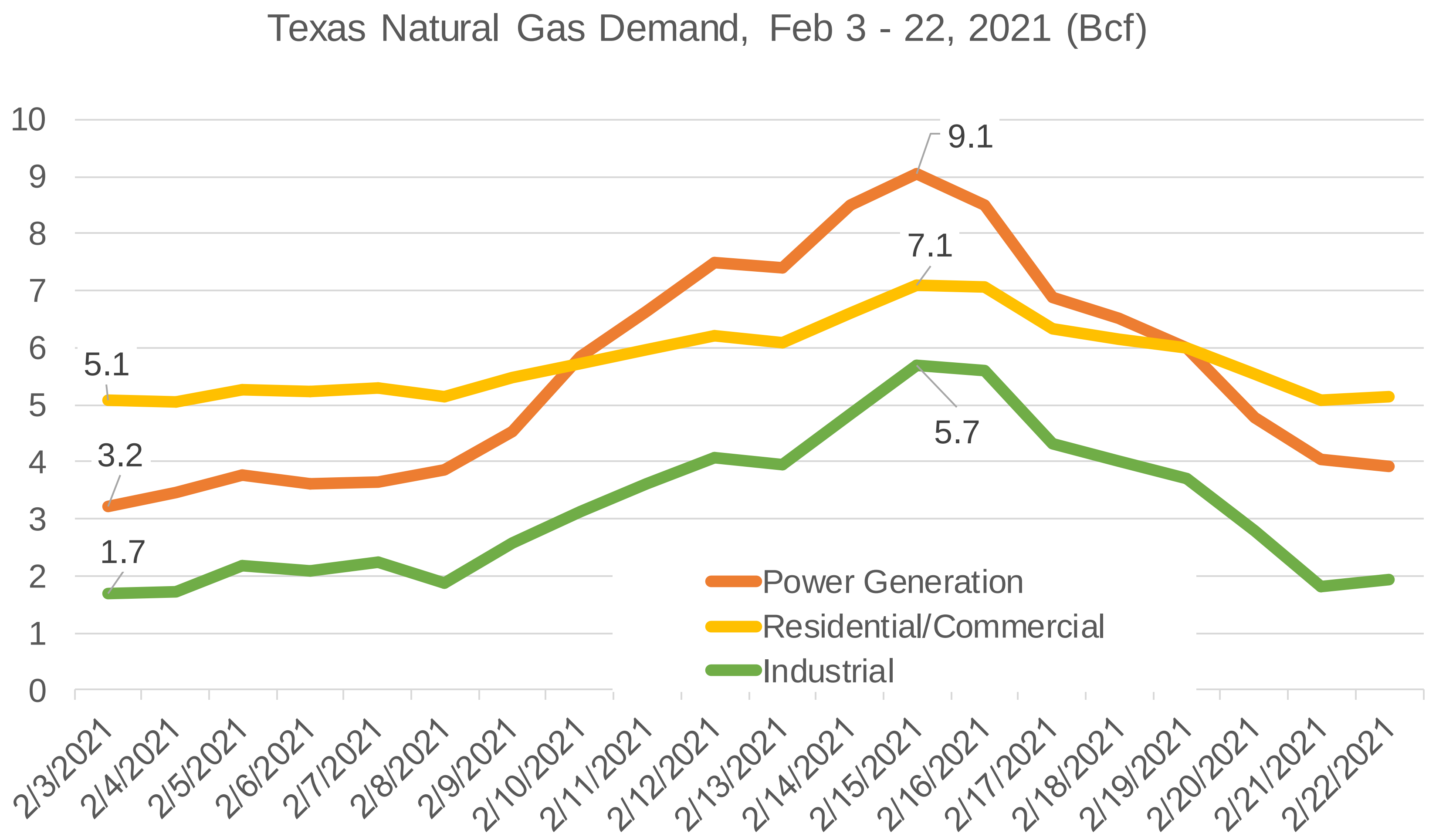
Temperature Deviation from Normal, Feb 14, 2021





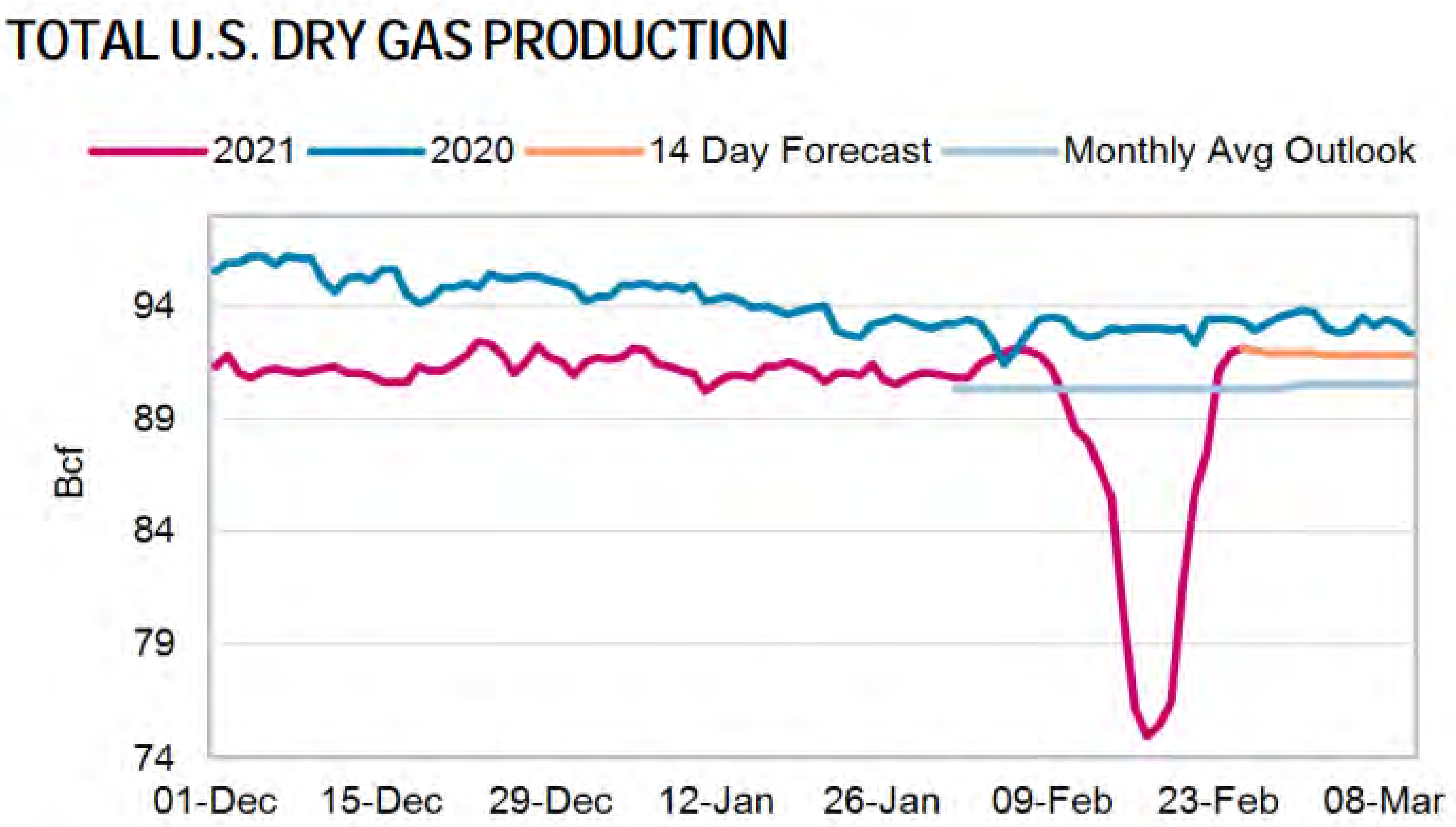
S&P Global Platts

Natural gas served to all Texas customers increased dramatically during the coldest days.



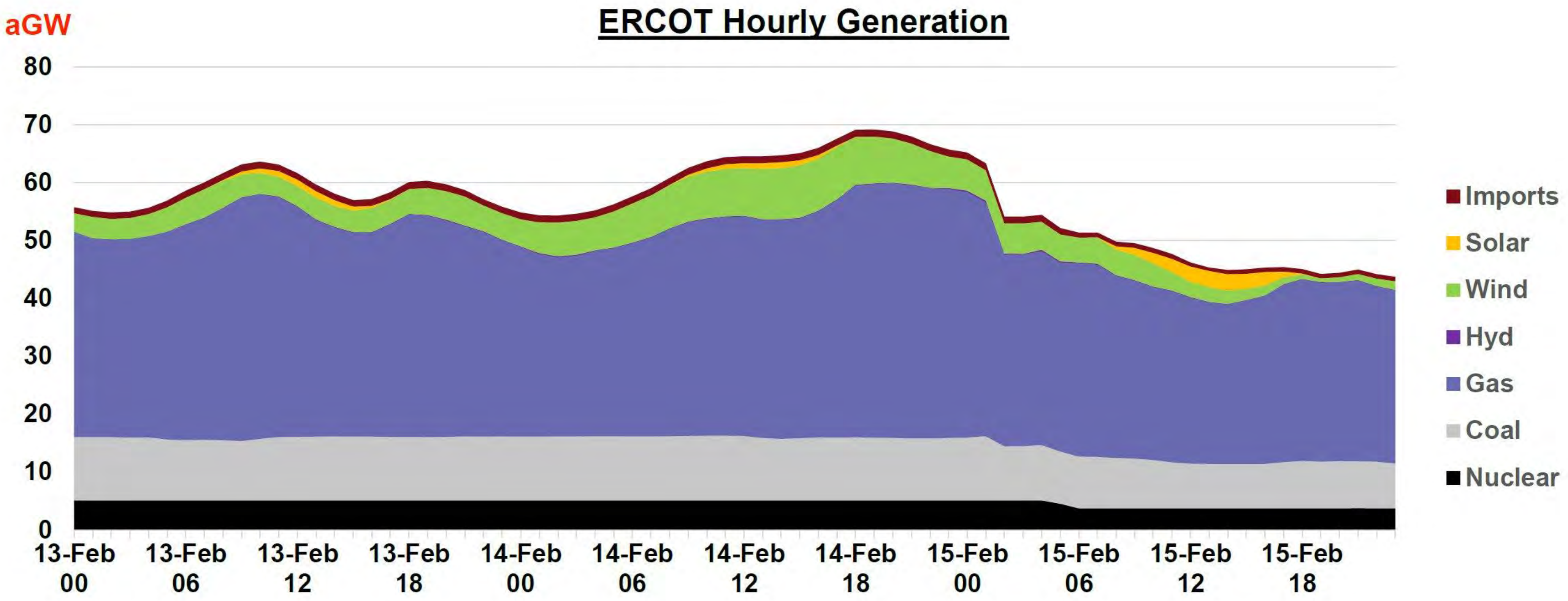
Data: S&P Global Platts

Natural gas production declined sharply as temperatures dropped, and then rebounded quickly.



S&P Global Platts

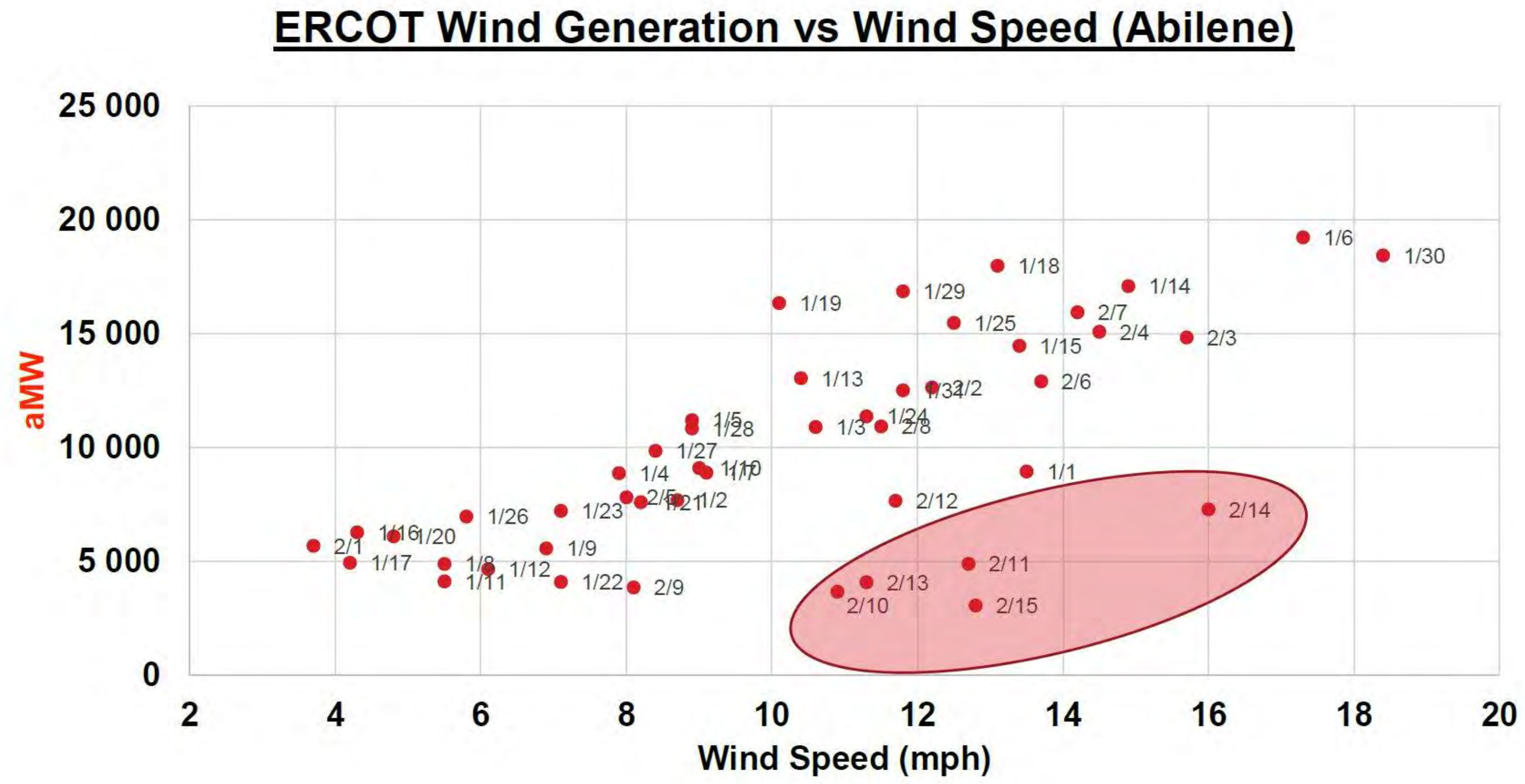
The largest declines in Texas (ERCOT) generation were due to gas-fired units. But, as you can see, natural gas continued to do the heavy lifting even as the grid was stressed under unprecedented demand.



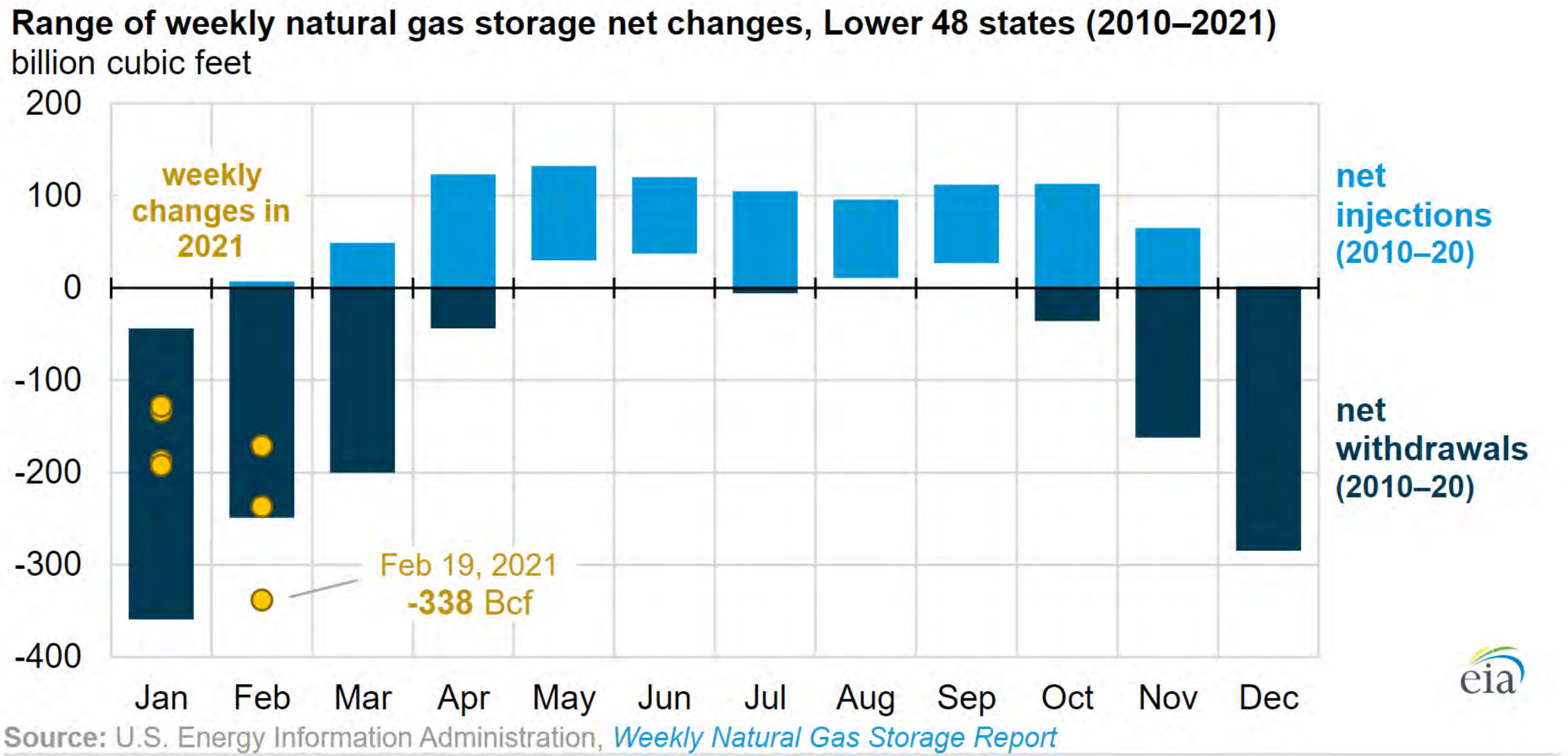
Source: ERCOT, S&P Global Platts Analytics

S&P Global Platts

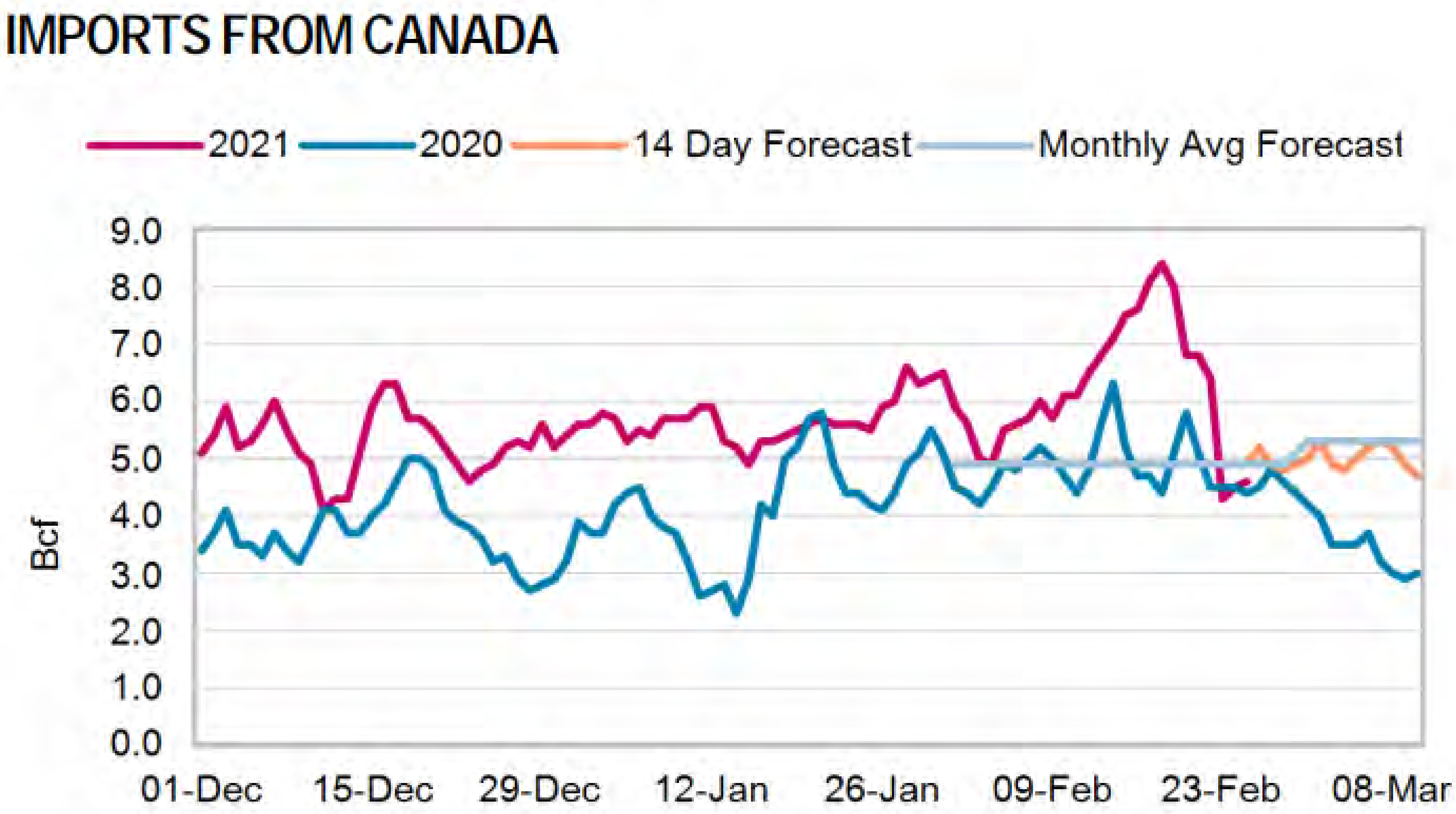
Wind generation in Texas (ERCOT) was well below levels at prevailing wind speeds only days and weeks before the cold event, suggesting severe temperatures were affecting equipment operation.



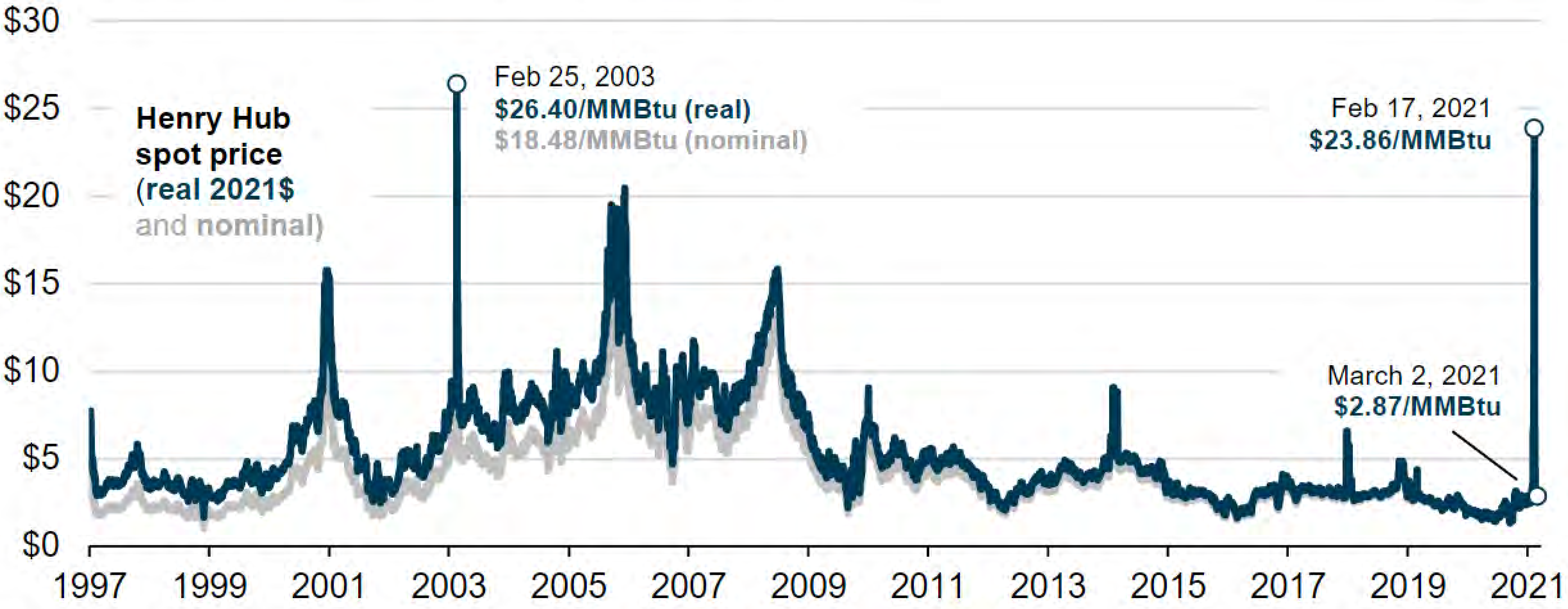
Natural gas storage stepped up in a big way to meet demand across the country.



The Canadian gas market played a key role.

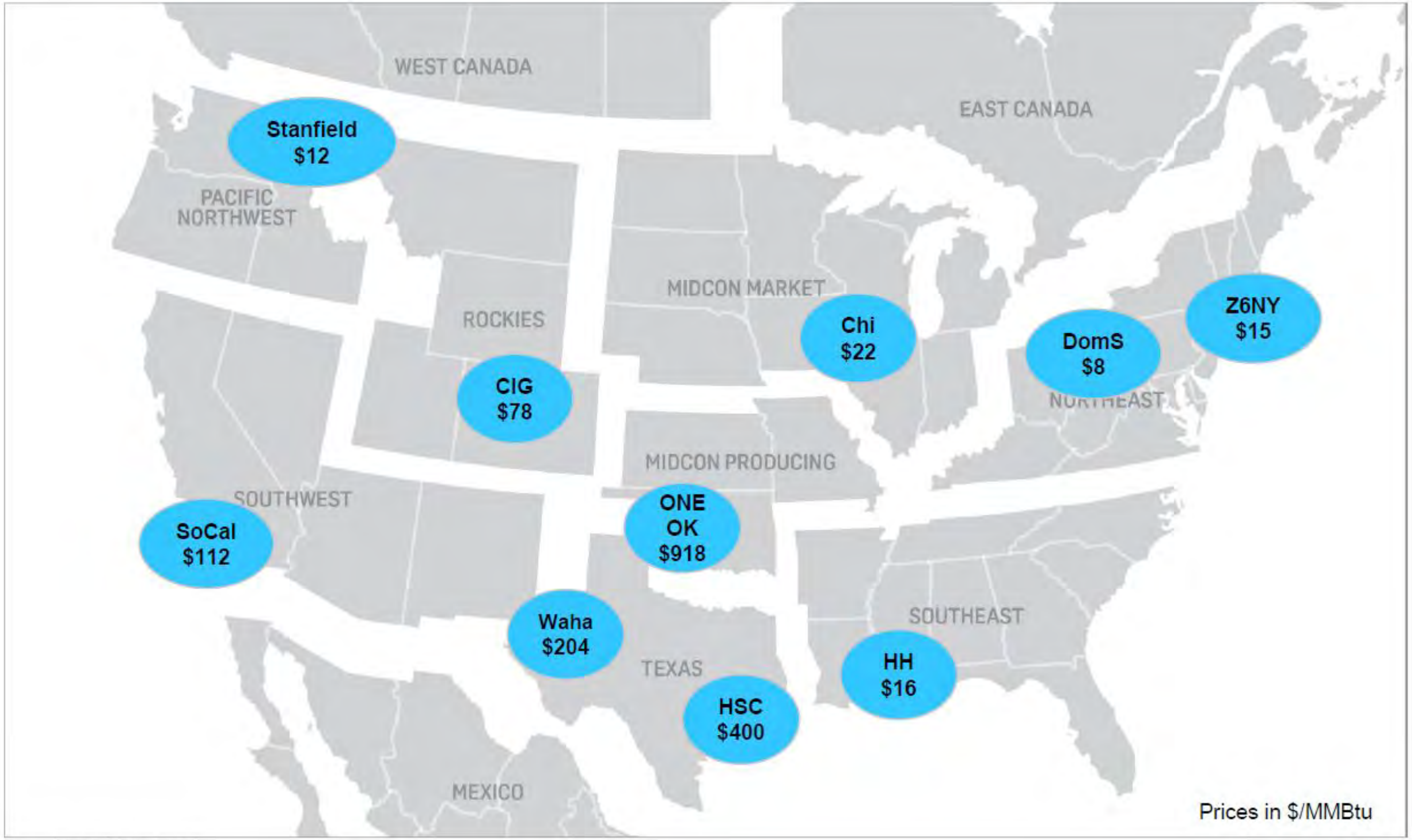


Daily Henry Hub natural gas spot prices (Jan 1997–Mar 2021)
dollars per million British thermal units (MMBtu)



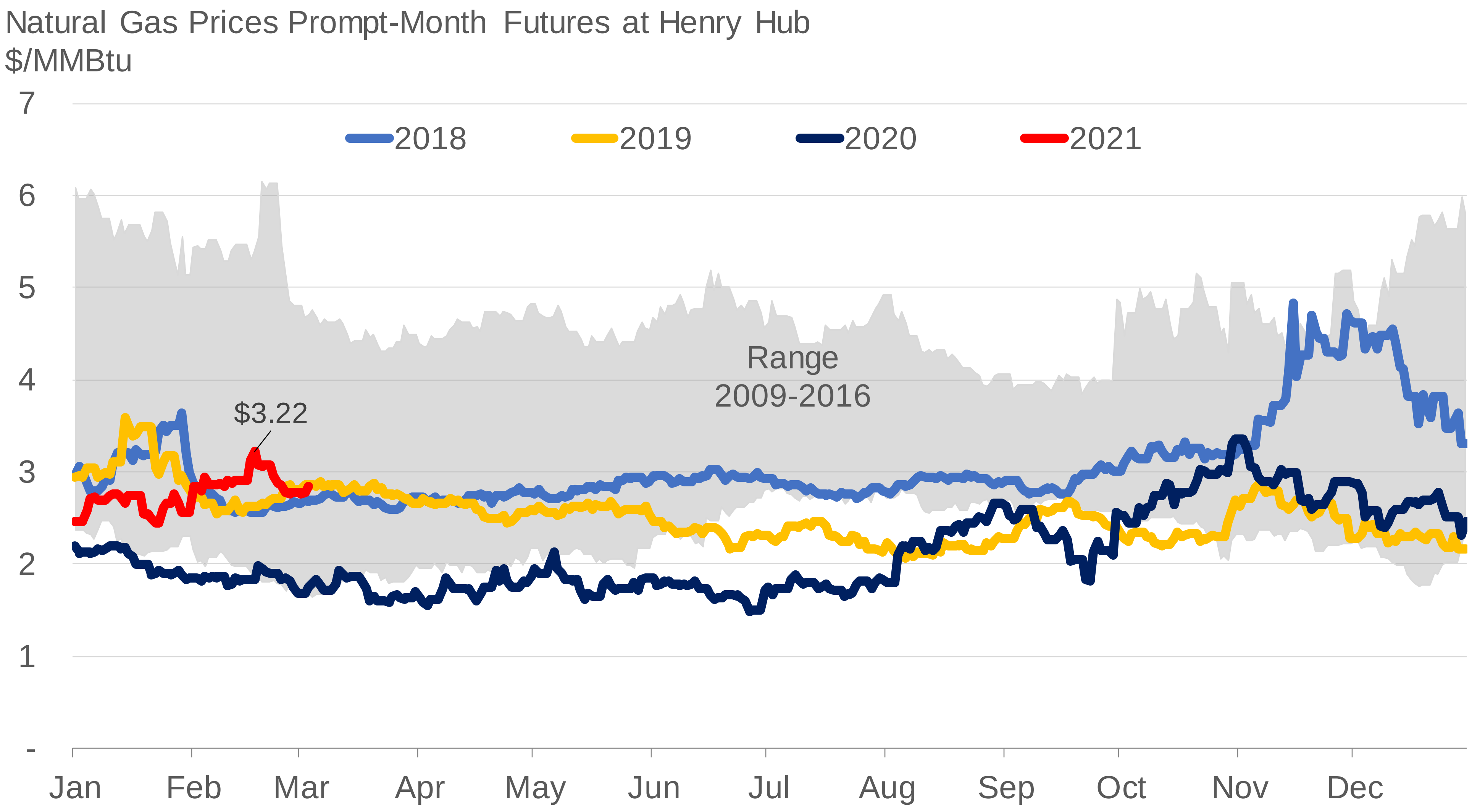
Source: U.S. Energy Information Administration, Henry Hub natural gas spot price

US natural gas prices surged due to supply constraints and record demand



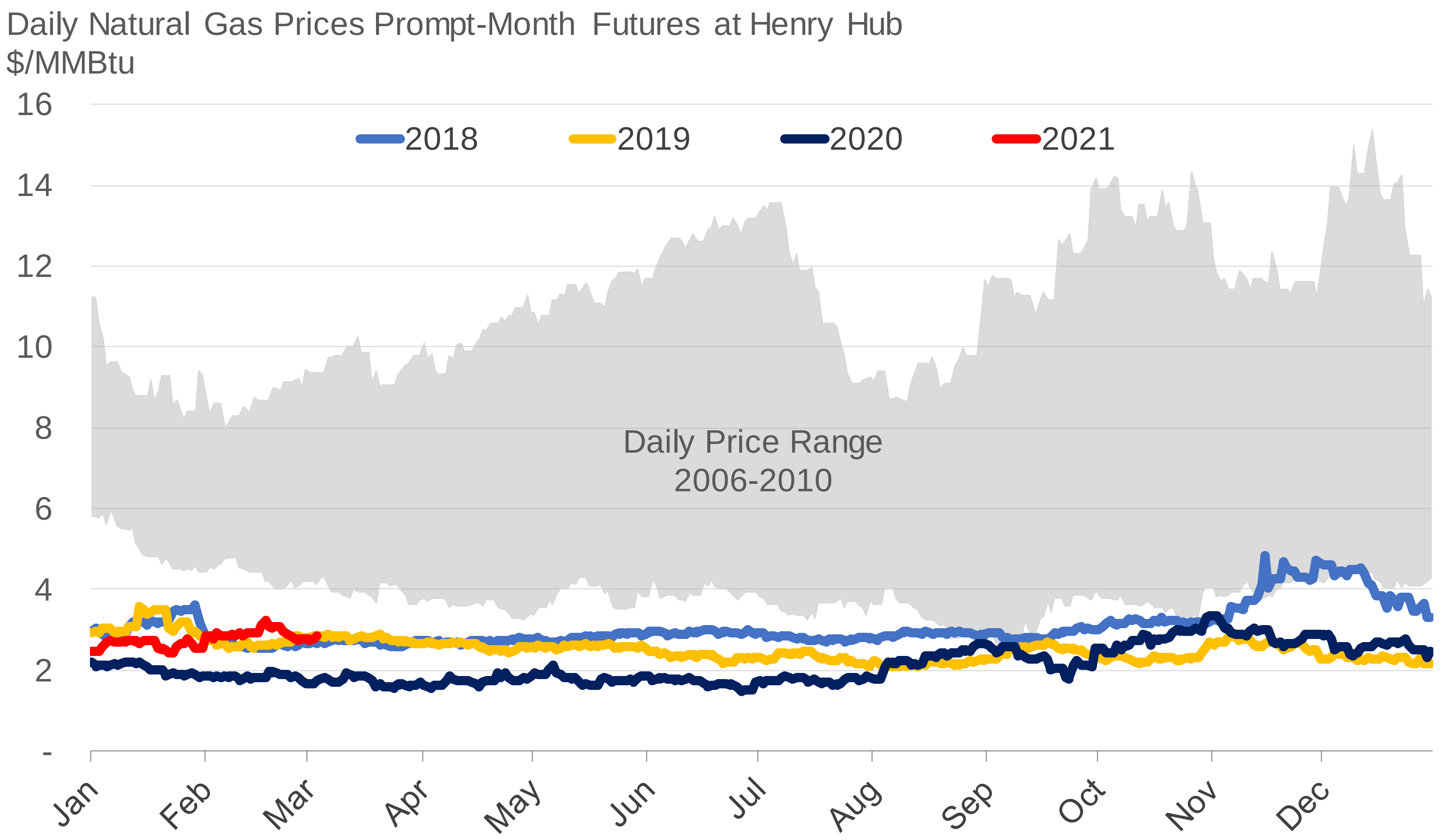
Source: S&P Global Platts Analytics

Despite the sharp increases in daily cash prices, futures contracts faced moderate pressure.



Data: Energy Information Administration

Natural gas prices remain the lowest in decades.



Data: Energy Information Administration

Early Lessons from the 2021 Cold Event

- Natural gas utility operations were largely uninterrupted during the cold event.
- Energy diversity of supply and end-uses is vital.
- Energy systems with heavy dependence on electricity for space heating will be challenged by exceptionally cold temperatures.
- Energy system resilience will be achieved through a diverse set of integrated assets.

Gas Utility Responses to Winter Storm Uri

- Ensuring safe and reliable operations across the life of the storm
- Making sure the financial impact to customers is as minimal as possible
  - Accessing capital to cover the extraordinary costs of gas experienced during the storm
  - Filings for the establishment of regulatory assets

State Regulatory Commission Responses to Winter Storm Uri

Commission ordered investigations into the impacts of Winter Storm Uri on customers and utilities

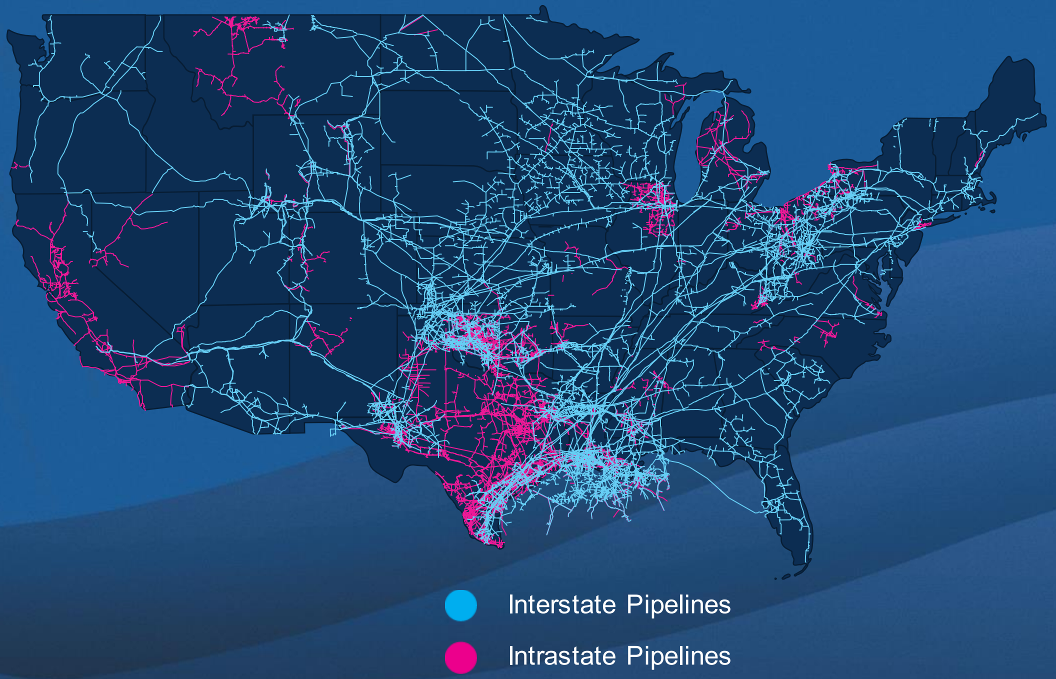
9 state regulatory commissions responded to the event with an ordered investigation

4 state regulatory commissions ordered some form of deferred cost treatment for costs relating to Winter Storm Uri

What were lessons learned from the interactions between state regulators and gas utilities?

- How can gas utilities better serve customers during these extraordinary events?
- The importance of gas supply and capital planning
- Effective strategies to minimalize extraordinary impacts on utility customers

Natural gas is delivered to customers through a 2.6-million-mile underground pipeline system. This includes approximately 2.3 million miles of local utility distribution pipelines and 300,000 miles of transmission pipelines that stretch across the country.



American Gas Association

TrueBlueNaturalGas.org

AGA_naturalgas

naturalgas

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The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 76 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent — more than 72 million customers — receive their gas from AGA members. Today, natural gas meets more than 30 percent of the United States' energy needs.

www.aga.org

SPP Southwest Power Pool

MARKET MONITORING UNIT

MMU MARKET REVIEW OF WINTER EVENT

KEITH COLLINS

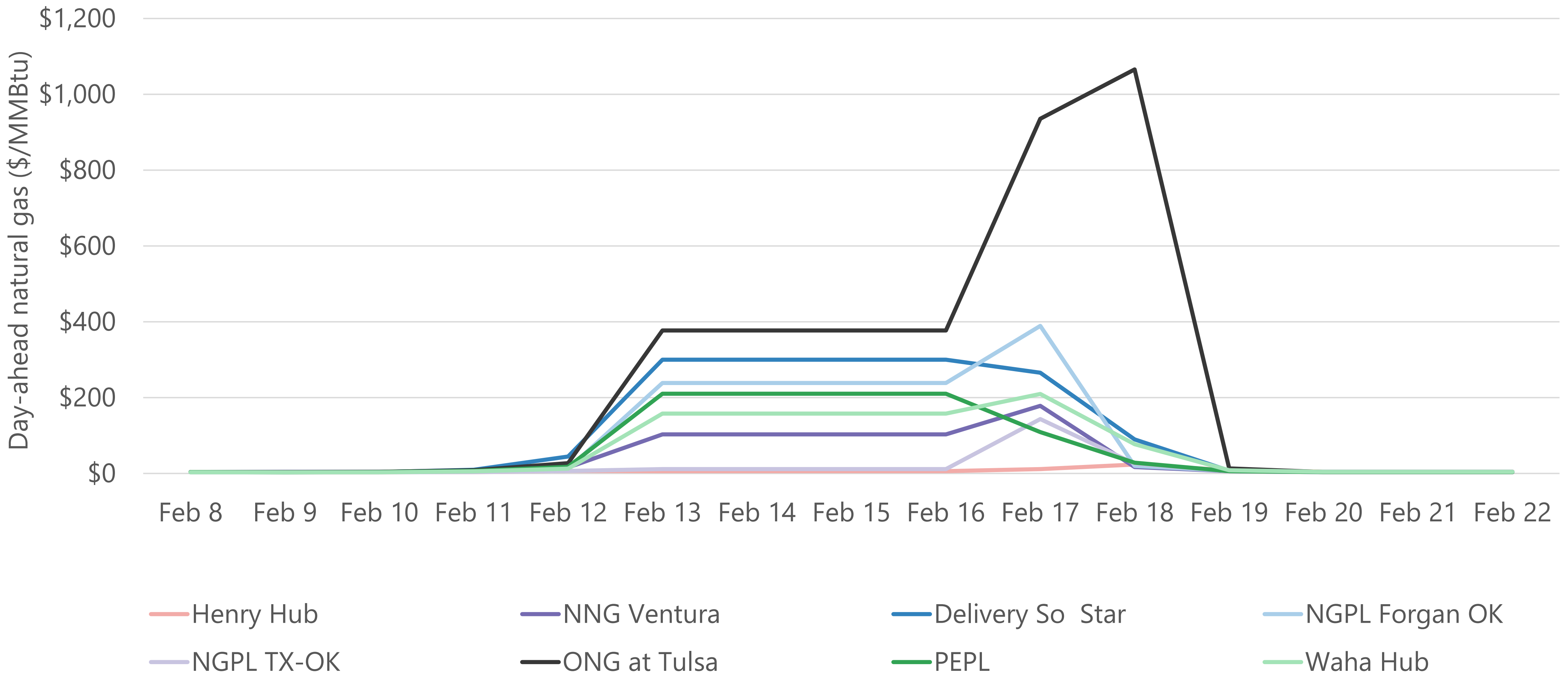
REGIONAL STATE COMMITTEE

APRIL 26, 2021

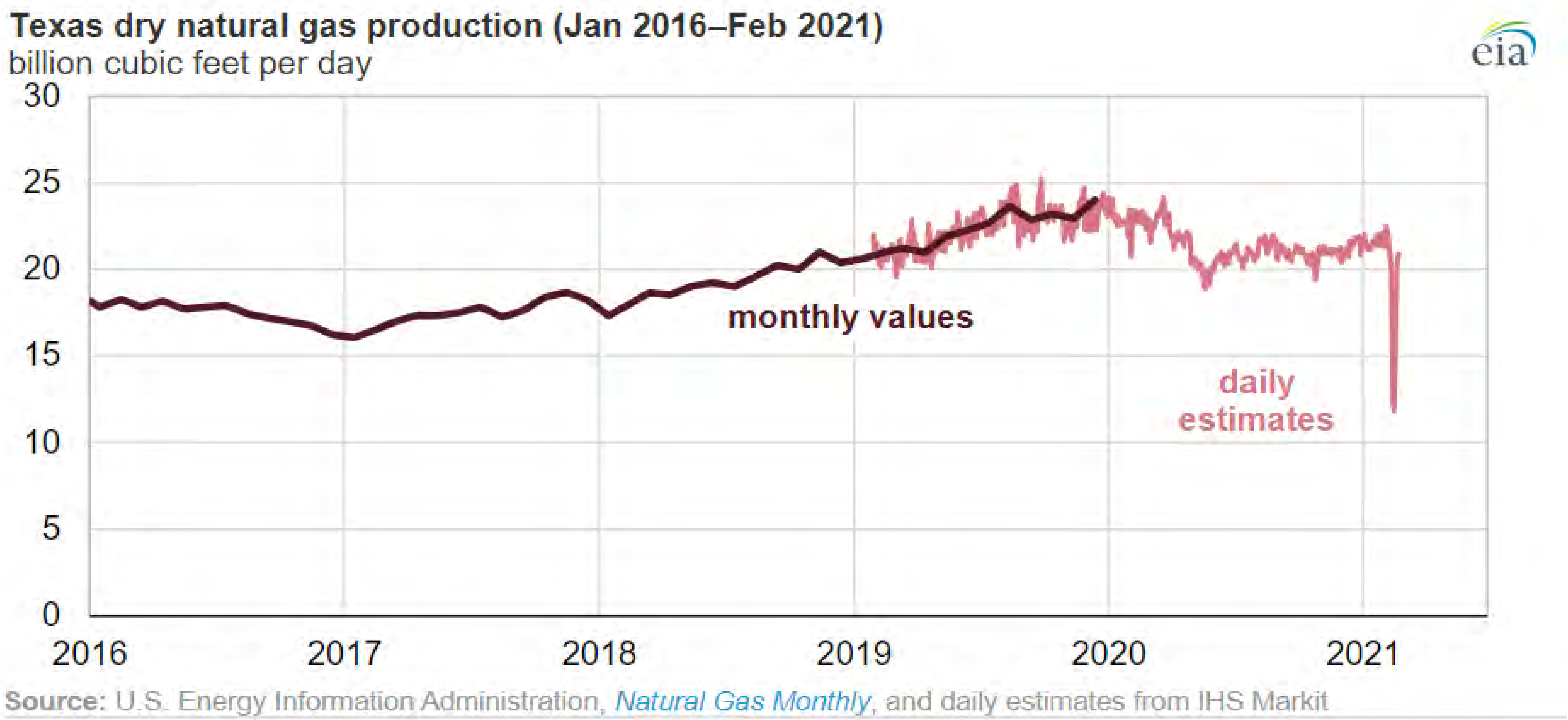
Helping our members work together to keep the lights on... today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

NATURAL GAS HUB PRICES

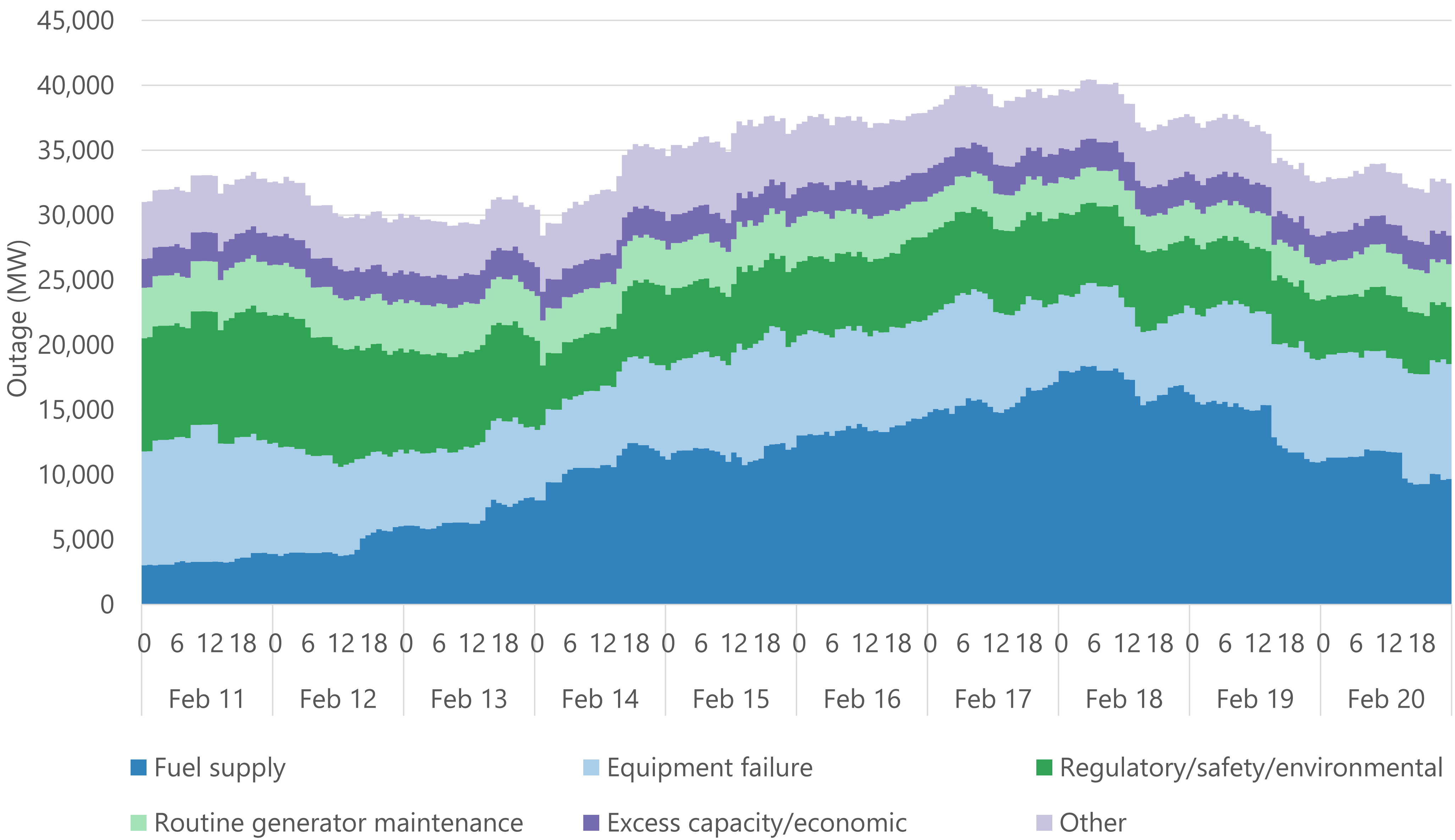


NATURAL GAS SUPPLY DROPPED SIGNIFICANTLY

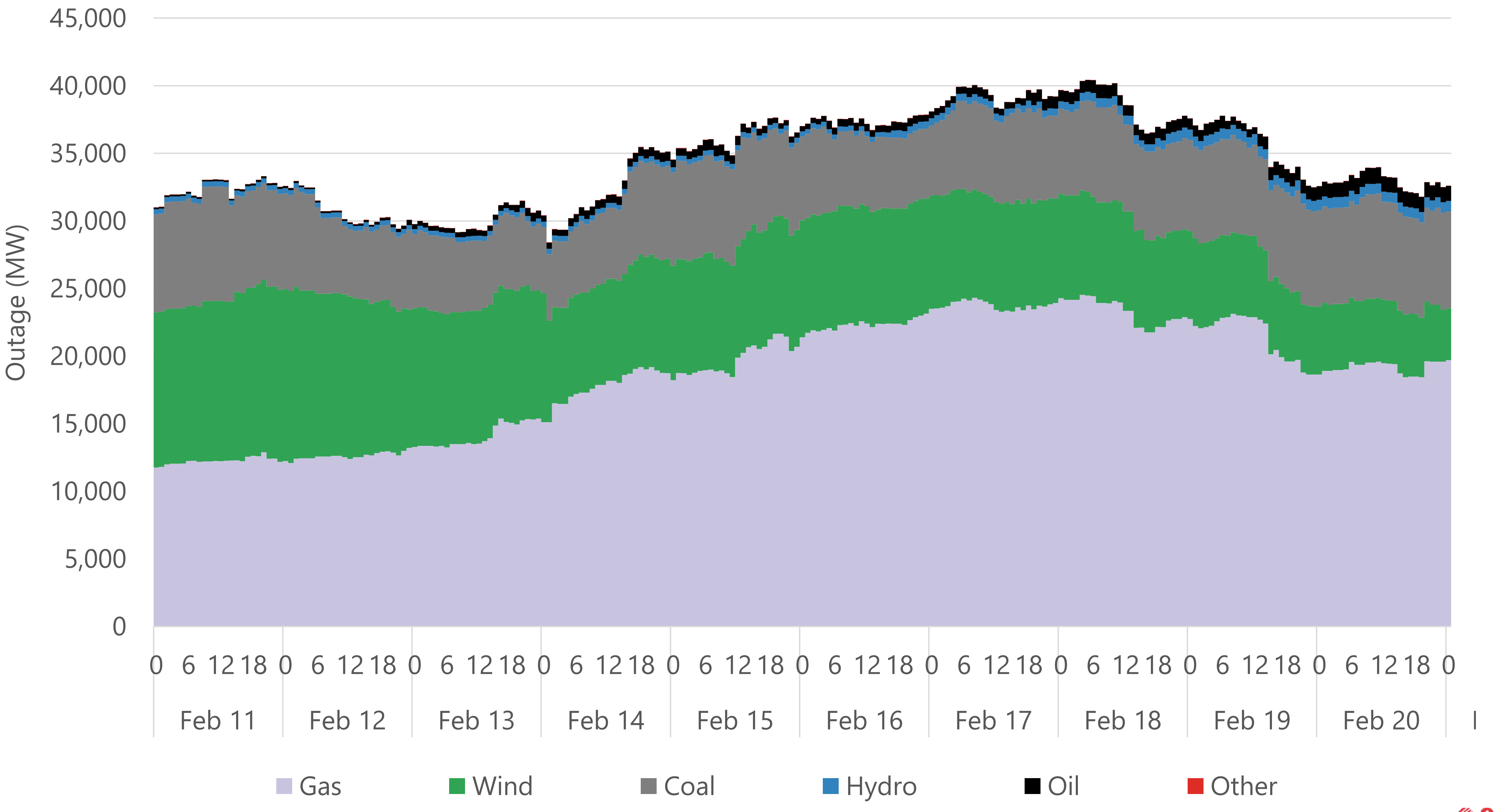


https://www.eia.gov/todayinenergy/detail.php?id=46896

GENERATION OUTAGES BY REASON

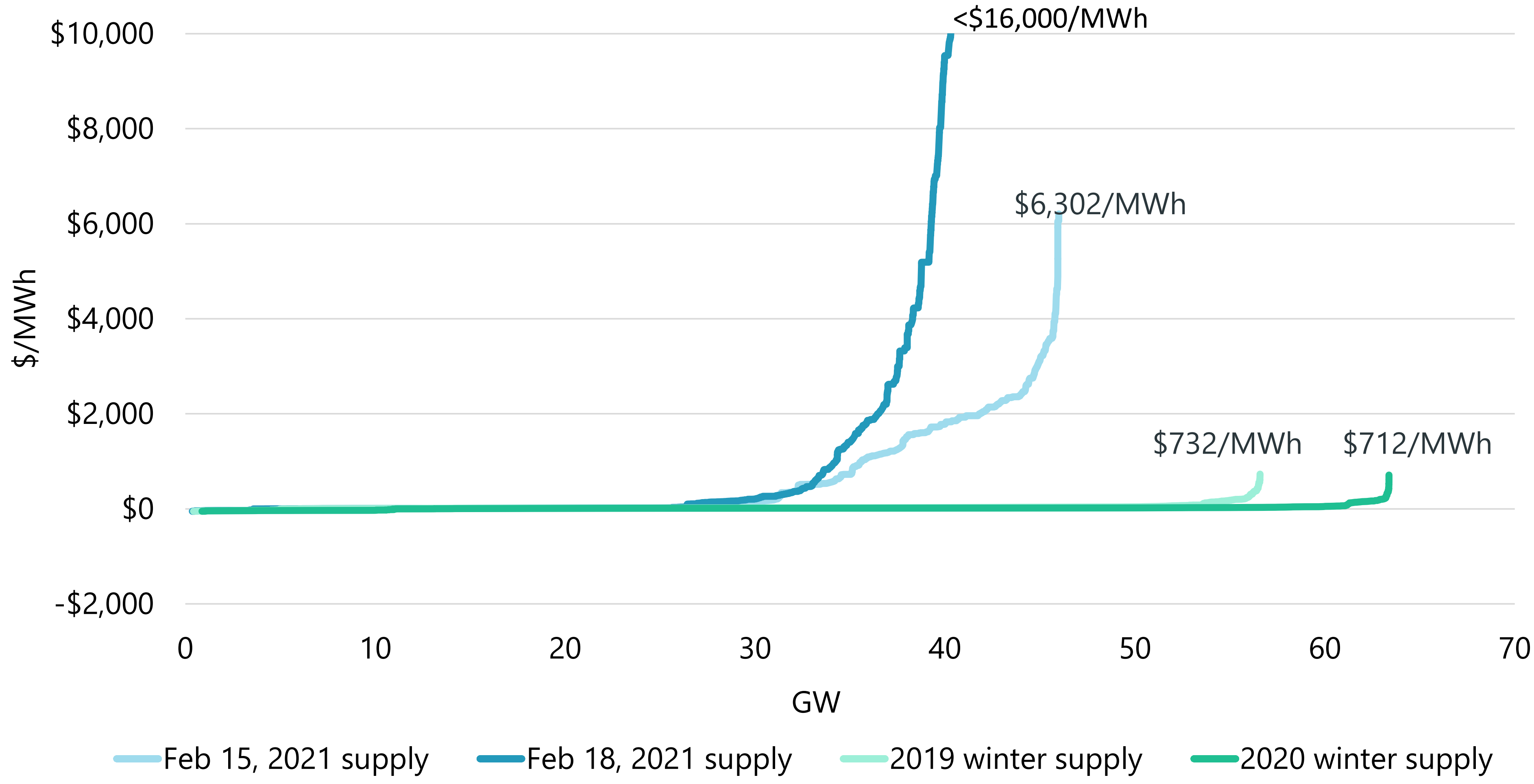


GENERATION OUTAGES BY FUEL TYPE

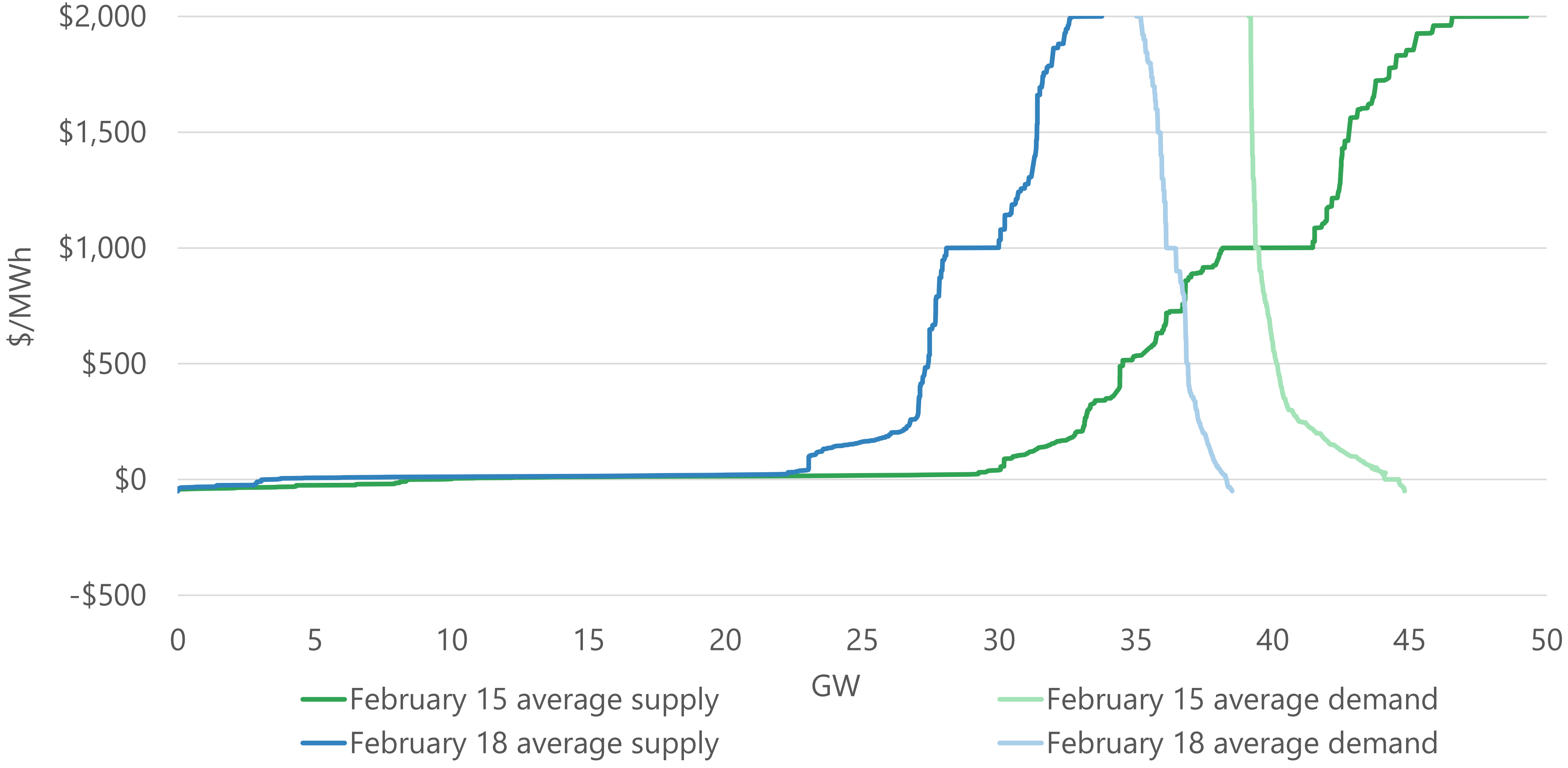


SPP MMU

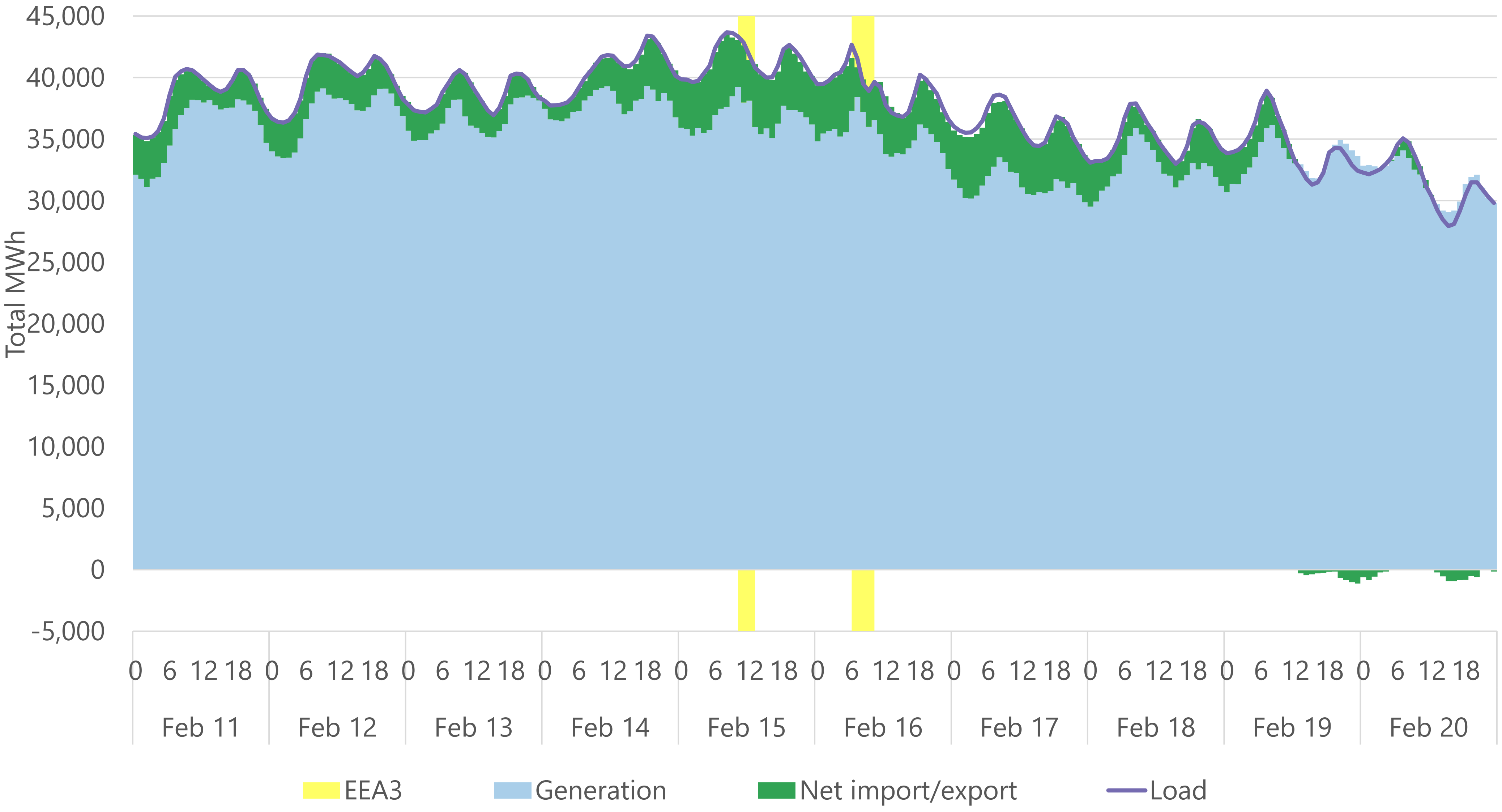
SUPPLY CURVE – UNCAPPED OFFERS



DAY-AHEAD SUPPLY CURVE – CAPPED OFFERS

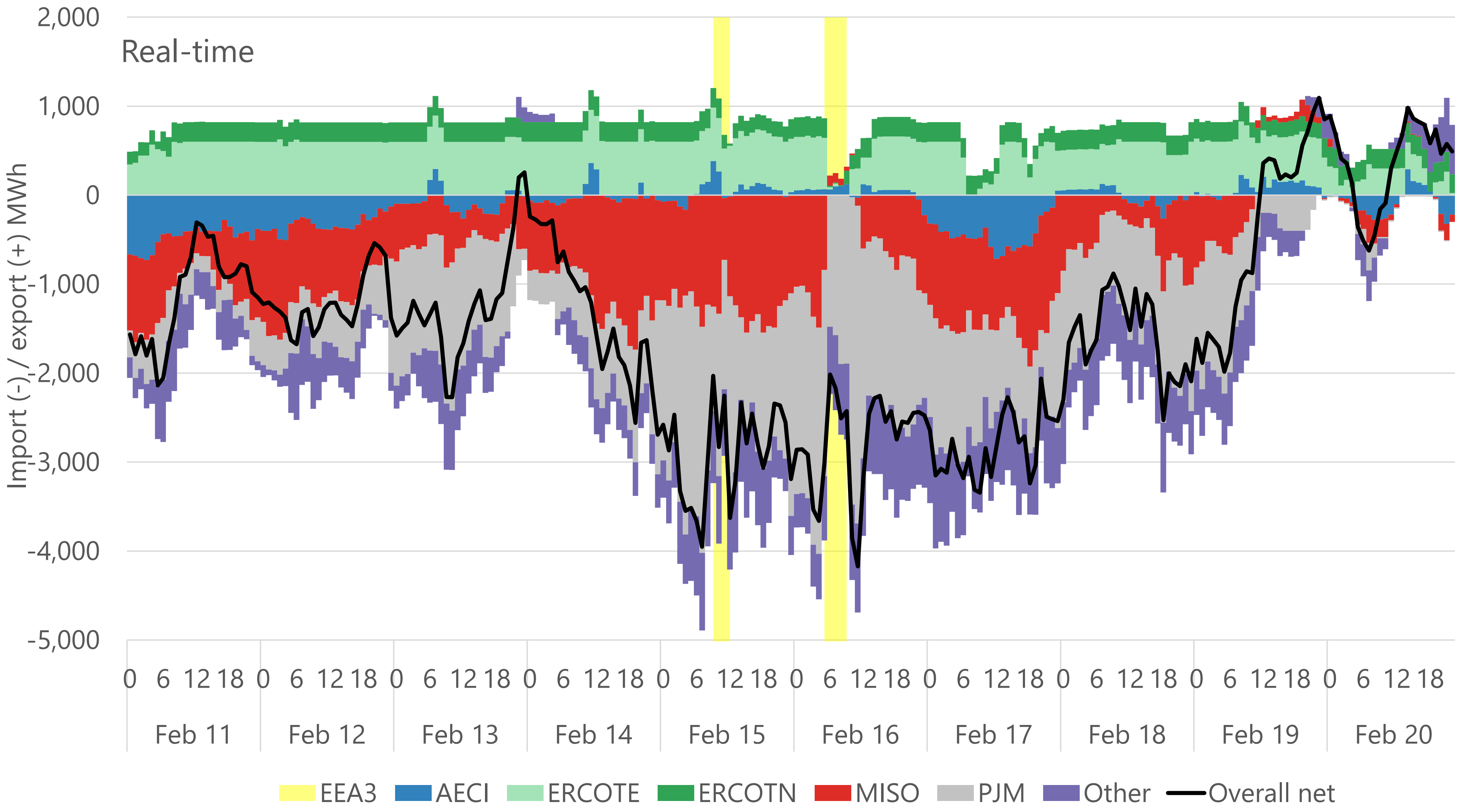


GENERATION AND NET IMPORTS/EXPORTS COMPARED TO LOAD

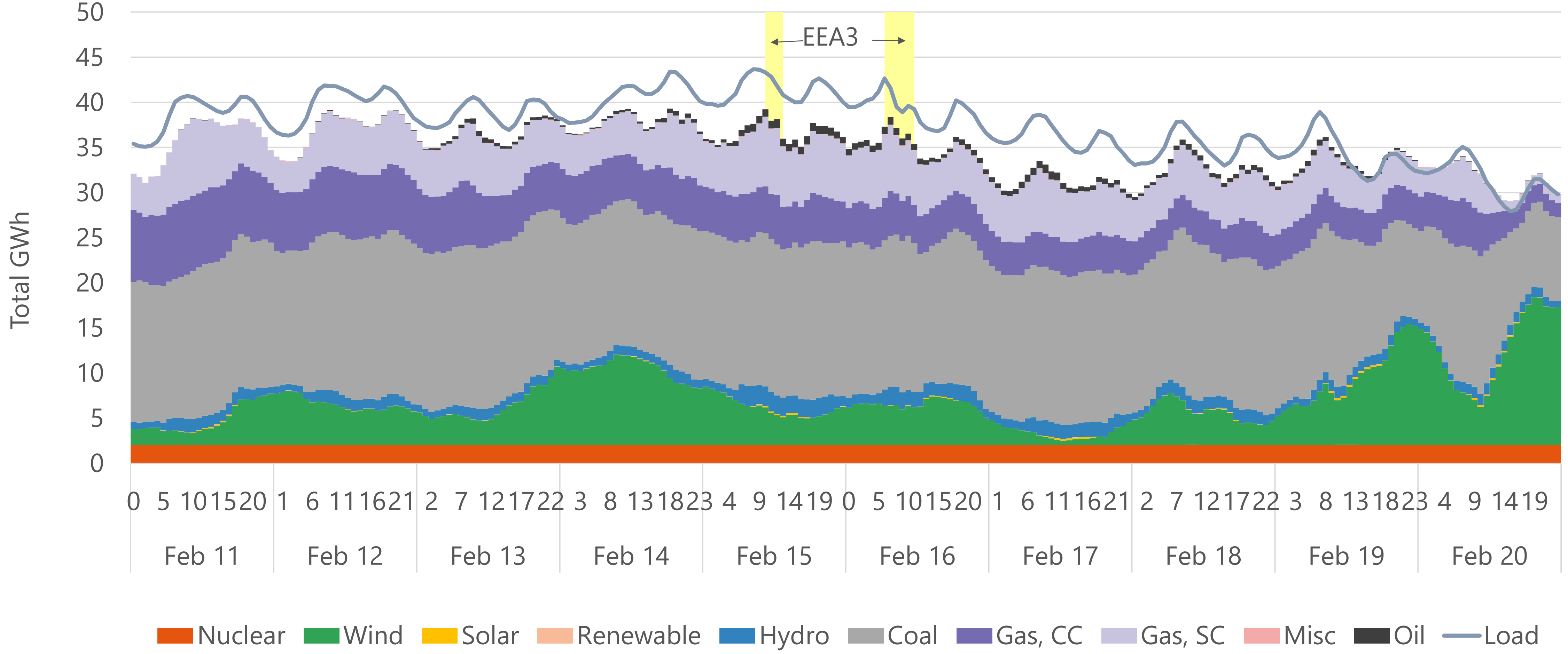


SPP MMU

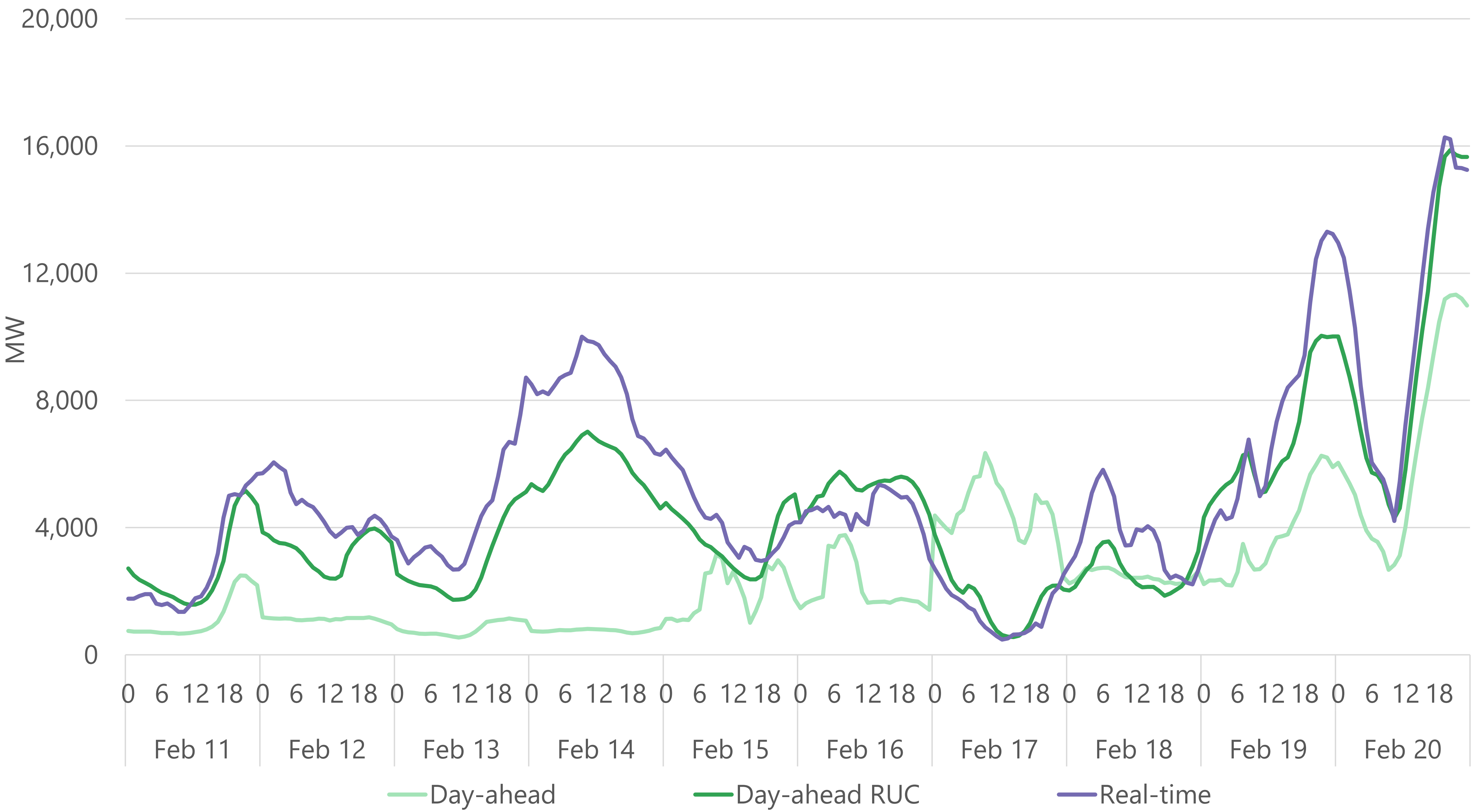
IMPORTS AND EXPORTS



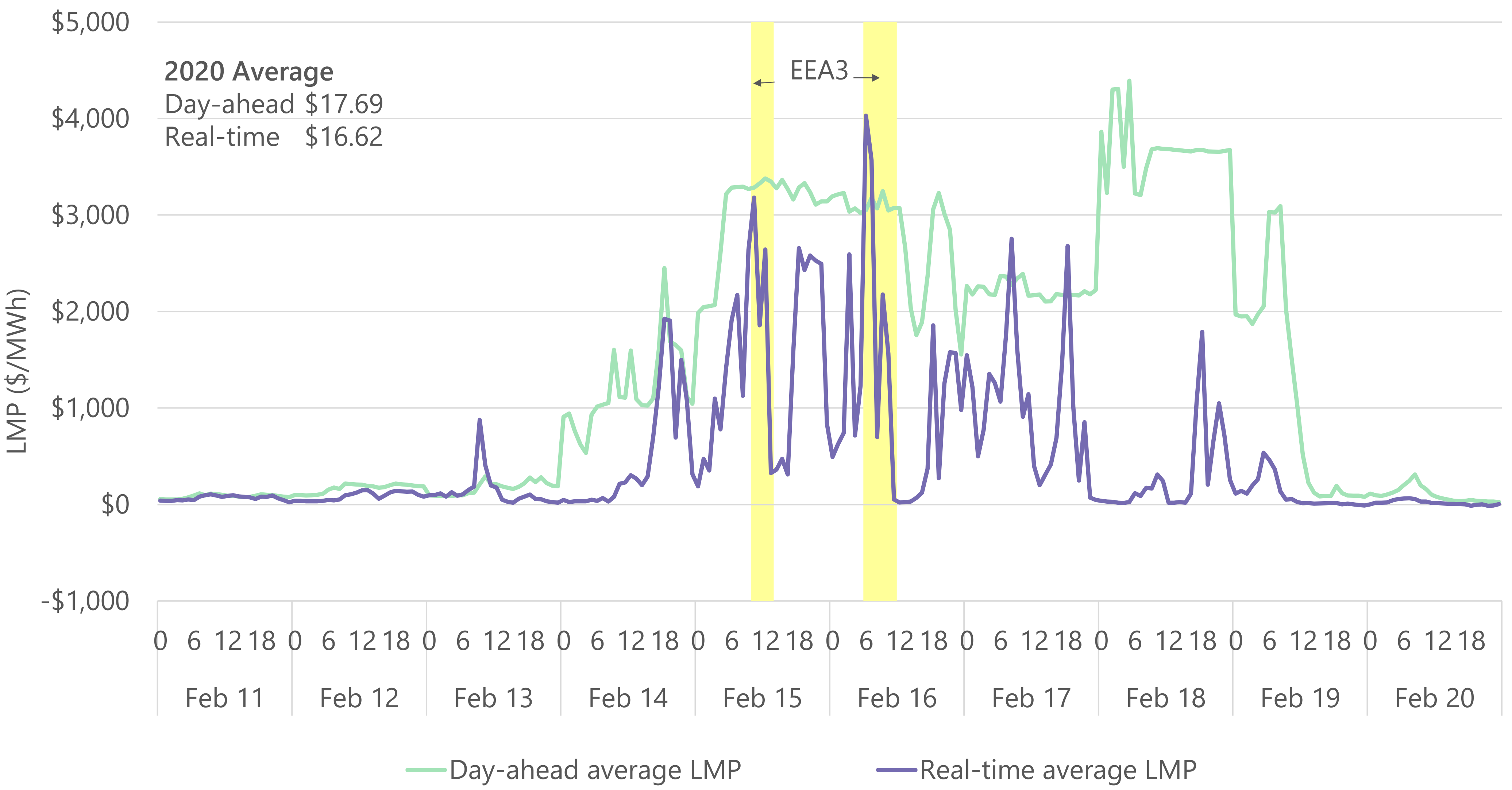
GENERATION BY FUEL TYPE



WIND GENERATION

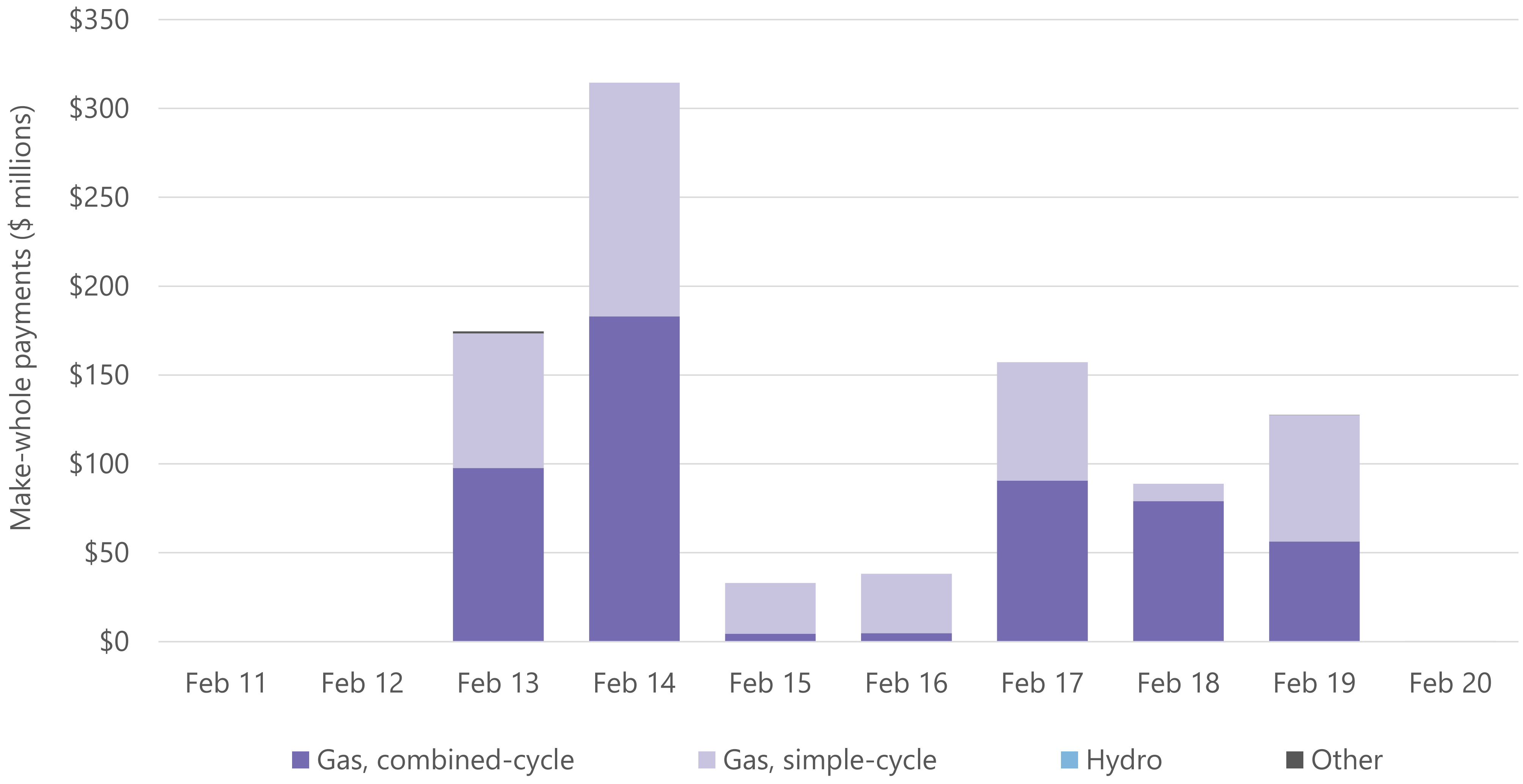


HOURLY ENERGY PRICES

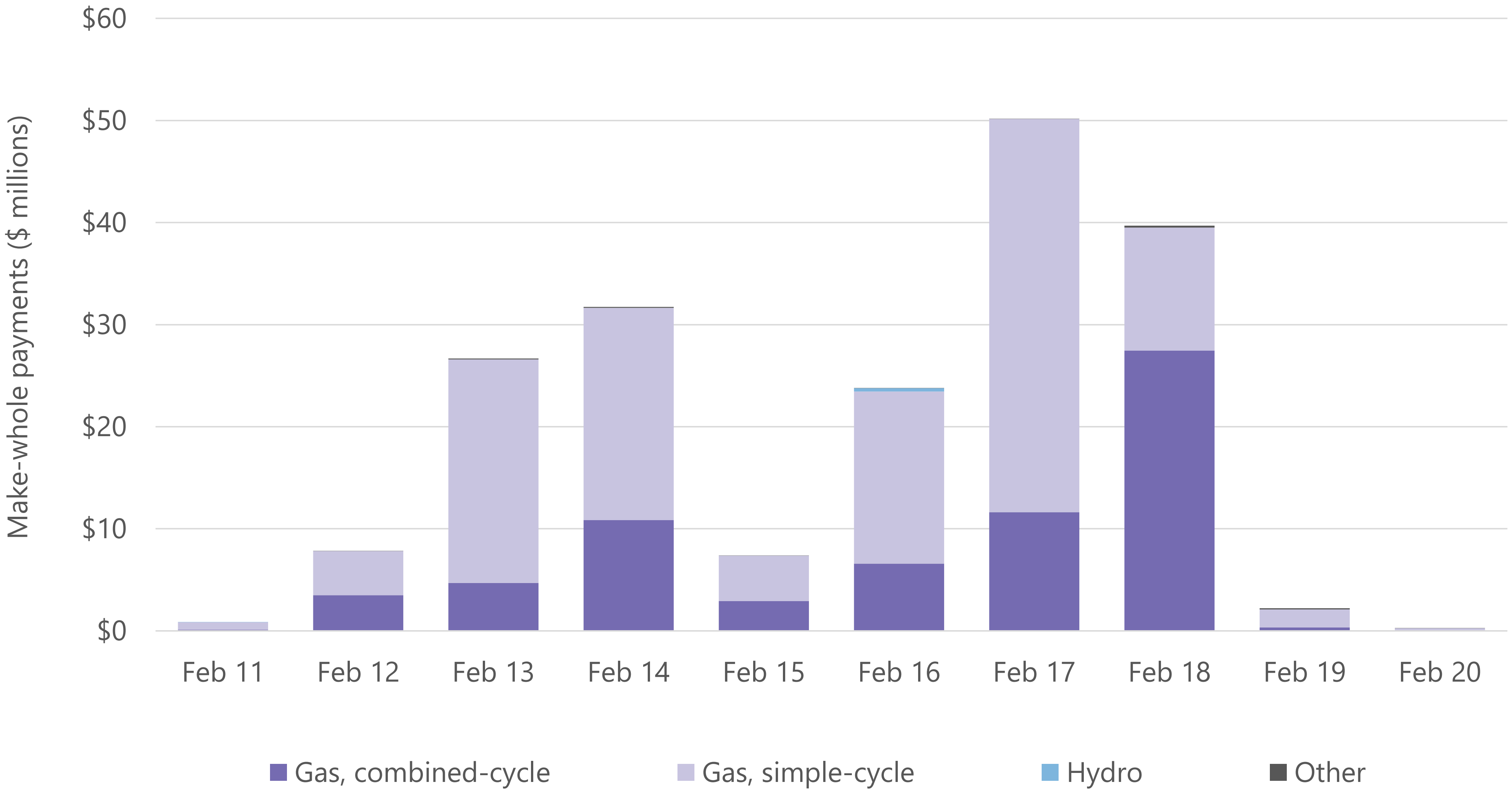


DAY-AHEAD SCARCITY

DAY-AHEAD MAKE-WHOLE PAYMENTS



REAL-TIME MAKE-WHOLE PAYMENTS



KEY TAKEAWAYS

- Overall, electric markets worked
  - High prices in SPP signaled imports from other regions
  - Imports addressed capacity shortfalls in SPP
- Fuel supply issues, primarily natural gas, were a primary cause of outages and resource scarcity
- Exorbitant prices for natural gas drove electric prices and costs

KEY QUESTIONS

- Should there be seasonal or monthly capacity requirements?
- Can natural gas resources be considered firm supply in winter?
- Should there be performance incentives/disincentives?
- How can gas/electric coordination be improved?
- What visibility should the RTO/market have with regards to resources behind the meter?
- How should economic outages be treated during emergencies?
- Could availability payments help manage outages?

QUESTIONS?

NRRI Insights *Practical perspectives on critical policy issues.*

MARCH 2021

The Intersection of Decarbonization Policy Goals and Resource Adequacy Needs: A California Case Study

Elliott J. Nethercutt and Chris Devon

A growing number of states have instituted renewable portfolio standards (RPS) through policies and corresponding commission orders to reduce carbon emissions in the electricity sector. No state has transformed its grid with more ambitious policies than California, which introduced its RPS in 2002, initially requiring 20 percent of retail electricity sales to be served by renewable resources within 15 years.[1] This program has been adjusted multiple times, most recently by Senate Bill 100 (SB100) in 2018, which increased the requirement for carbon-free generation from electric retail sales to 60 percent by 2030 and 100 percent by 2045. The California Public Utilities Commission (CPUC) is charged with implementing this RPS program and administering compliance over the state's investor-owned utilities (IOUs), Energy Service Providers (ESPs), and community choice aggregators (CCAs).[2] The CPUC is also responsible for ensuring that jurisdictional load-serving entities (LSEs) procure enough capacity to meet the commission's resource adequacy program requirements.[3] These two objectives collided on August 14 and 15, 2020, when the California Independent System Operator (CAISO) called on utilities to initiate controlled rotating electricity outages on two occasions to maintain adequate reserves in the midst of a regional heat wave. These two load-shedding events affected 491,600 and 321,000 customers, respectively.[4] California's electric system was ultimately unable to maintain reliable operations for the first time in almost two decades.

Significant loss-of-load events on the bulk power system often result from a combination of factors. After months of collaborative investigation, the CPUC, the CAISO, and the California Energy Commission (CEC) released a final root cause analysis (referred as "root cause analysis" throughout this paper) that identifies several operational factors that contributed to the events, including: actual loads exceeding forecasts; significant variability in wind and solar output; reduced imports from neighboring states (due to transmission constraints, market rules, and high demand throughout the Western Interconnection); and significant unit derates and forced outages. According to the root cause analysis, two of

1 California is one of several states with aggressive clean energy targets, requiring 100 percent carbon-free electricity by 2045. According to the NCLS, 14 states have RPS goals of 50 percent or greater by 2045. The types of resources that qualify for California's RPS have evolved. For additional information, see Section 399.12 of Senate Bill 1078 and the CPUC's RPS Program and Legislative History.

2 The California Energy Commission (CEC) is responsible for the certification of generation facilities as eligible renewable energy resources and adopting regulations for the enforcement of RPS procurement requirements of publicly owned utilities.

3 A 1-in-2 forecast assumes there is a 50 percent probability that the forecasted peak will be less than actual peak load and a 50 percent probability that the forecasted peak will be greater than actual peak load. The demand forecasts are adopted by the CEC as part of its Integrated Energy Policy Report (IEPR) process. The 15 percent planning reserve margin (PRM) includes 6 percent to meet the Western Electricity Coordinating Council (WECC)-required grid operating contingency reserves, plus a 9 percent planning contingency to account for plant outages and higher-than-average peak demand, CAISO/CPUC/CEC Final Root Cause Analysis, p. 11.

The 50/50 load forecast assumes a normal distribution. For example, if the forecasted load for a system is 25,000 MW, there is a 50 percent chance actual load will be higher, and a 50 percent chance load will be lower.

4 Total customer outages amounted to 491,600 on August 14 and 321,000 on August 15, CAISO/CPUC/CEC Final Root Cause Analysis, p. 35.

the three primary causal factors were related to resource planning targets that "have not kept pace" with the changing resource mix, leading to insufficient resources available to meet demand during the early evening hours.[5] The August events highlight the need for continued improvement to resource adequacy constructs, along with developing and implementing enhanced metrics to accurately assess an electric system that continues to be transformed by ambitious state decarbonization policies.

In this *NRRI Insights* paper, we examine how the evolution of California's RPS program has led to increasing system variability with higher potential for reliability events—particularly during extreme weather conditions. We further explain how the rapid retirement of baseload and dispatchable generation has outpaced replacement capacity with adequate characteristics needed to maintain system reliability. We discuss the CPUC's recent finding that future procurement decisions must balance RPS requirements with resource adequacy needs. We then explore how the continued development of advanced reliability metrics can help bridge the gap between decarbonization policy goals and resource adequacy needs. Throughout this paper, we review the ongoing CPUC and CAISO actions in response to the ongoing supply shortages and offer some additional proposals aimed at improving the state's near- and long-term reliability outlook.

California's Decarbonization Policies and System Reliability

The California legislature established the first RPS program in 2002, with subsequent decisions and process modifications introduced by the CPUC.[6] Additional legislation with more stringent requirements and associated compliance timelines were signed into law in 2003, 2005, 2015, and 2018.[7] Load-serving entities repeatedly demonstrated that they could interconnect large amounts of utility-scale wind and solar, while large amounts of rooftop photovoltaic were also installed behind the meter. During this period of relatively rapid system transformation, the CAISO continued to operate the system without any major events, reinforcing the idea that policy-makers could introduce more ambitious RPS requirements without compromising grid reliability.[8] The CAISO has facilitated the interconnection of large amounts of utility-scale wind and solar by providing open and non-discriminatory access to the wholesale transmission grid and supporting comprehensive infrastructure planning through dozens of stakeholder initiatives. These initiatives led to the deployment of over 13 gigawatts (GW) of utility-scale solar and 7 GW of wind on the CAISO system in under 18 years.[9] As a result, the CAISO system is currently able to serve over 80 percent of demand with renewables during certain periods, double the amount reported in 2015, and more than any other system in the country (**Figure 1**).[10]

The Decline of Baseload and Dispatchable Resources in California

California's rapid and ongoing growth of intermittent resources like wind and solar has flourished, while baseload and dispatchable resources have

5 CAISO/CPUC/CEC Final Root Cause Analysis, p. 1.

6 See the CPUC RPS website for a complete list of the state's RPS program.

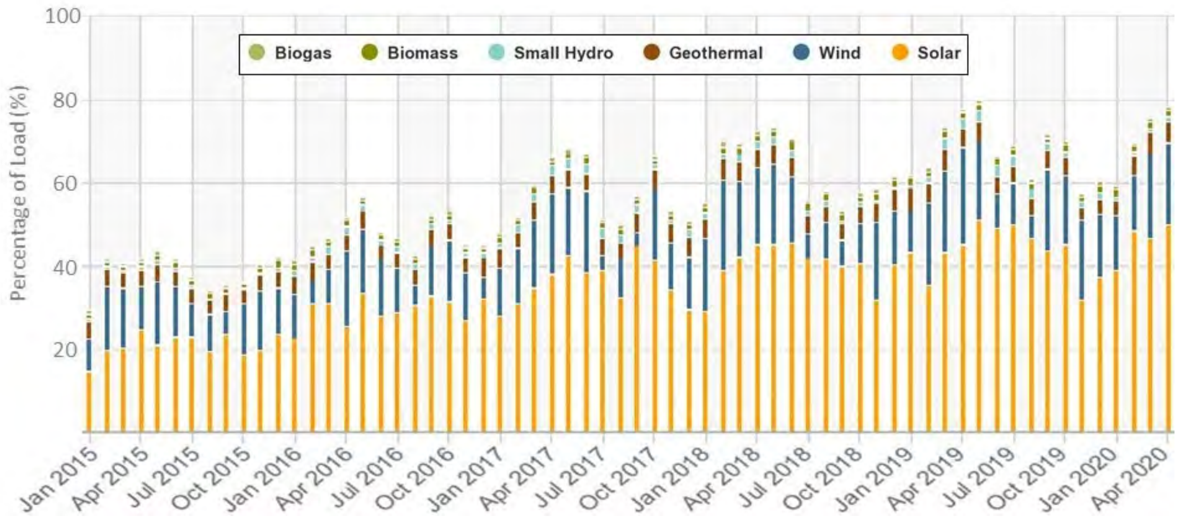
7 The 2003 Energy Action Plan I accelerated the 20 percent deadline from 2017 to 2010 (Senate Bill 107 (2006) codified the accelerated deadline into law). The 2005 Energy Action Plan II examined a further goal of 33 percent by 2020. Senate Bill 350 (2015) required all in-state utilities to source half of their electricity sales from renewable sources by 2030.

8 California's electric system had not experienced wide-spread rotating outages since 2001, when the CAISO declared a Stage 3 emergency leading to the controllable firm load-shedding during the California Energy Crisis. The 2011 Southwest Blackout was not a controlled load shedding event, rather it was determined that the system was not operating at an N-1 state.

9 California Energy Commission's Electric Generation Capacity and Energy data indicates 11.2 GW of solar additions and 4.4 GW of wind additions between 2001 and 2019. In July 2020, the CAISO footprint has 13,383 MW of utility-sale solar and 6,977 MW of wind.

10 The CAISO system served a record 81.88 percent of system demand with renewable generation on May 2, 2020 at 1:40 p.m. The CAISO chart does not show May 2 record of renewables serving demand. Chart modified and resized by authors.

Figure 1: CAISO Monthly Maximum Percent of Load Served by



declined.[11] In 2012, the San Onofre Nuclear Generating Station (SONGS) plant was taken offline and permanently decommissioned one year later. SONGS had provided 2.2 GW of zero-emission baseload generation in close proximity to the densely populated Southern California load pockets. Four years later, plans were announced to close the state's remaining nuclear plant, Diablo Canyon, by 2025. Its two reactors total 2,160 MW and serve three million customers. Nuclear plants maintained an average 2019 capacity factor of 93 percent, compared to approximately 24 percent for solar. Thus, it would require at least 6 GW of nameplate solar capacity to fill the void created by the retirement of the Diablo Canyon plant.[12]

Figure 2: Nuclear Generation in California (2012-2025)

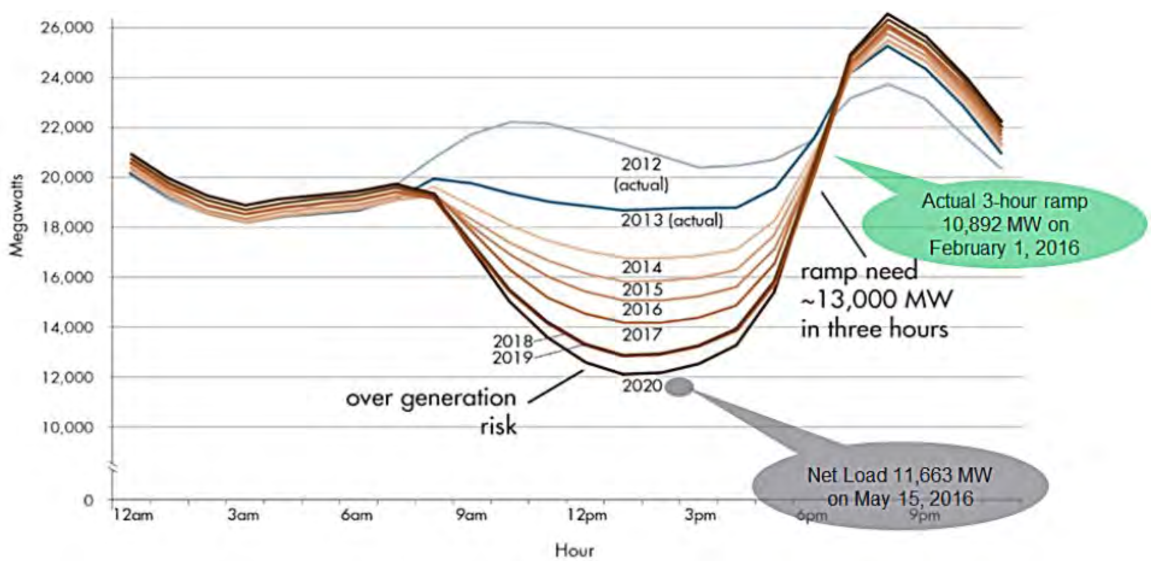
11 Baseload generation includes power plants with high capacity factors that are able to be operated at sustained output levels with limited cycling or ramping. Examples includes most nuclear, coal, and natural gas steam generators, none of which qualify toward achieving the state's RPS. California has essentially retired all coal-fired capacity.

12 EIA 2019 Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels; EFI: Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, p. 40.

In addition to the ongoing loss of baseload generators, dispatchable resources that are highly responsive to intermittent resources are also in decline. Ramping concerns initially emerged as a growing challenge for the CAISO more than a decade ago. Today, the majority of the state's solar resources are not dispatchable by the CAISO, but are located behind-the-meter on customer rooftops.[13] Solar output from these distributed resources (in aggregate) offsets what would otherwise be higher system loads. However, output rapidly declines after the sun sets, creating a steep ramp in demand that must be served by other resources on the CAISO system. During the same period, residential electricity demand also increases, as customers return home from work and use more appliances during the late-afternoon and early-evening (especially air conditioning). This load pattern, often referred to as the duck curve (and more recently referred to as "net-load ramps"), is exacerbated by the long, narrow, north-south geographic orientation of the state (**Figure 3**).[14, 15]

The ongoing challenges associated with meeting increasingly steep net load ramps were identified in the joint report as a contributing factor to the August 2020 events.[16] Concerns about insufficient ramping capability on the system were initially recognized by the CAISO Board of Governors in 2011 and resulted in their approval of a flexible ramping constraint interim compensation methodology. The resulting market policy established a flexible ramping product to address ". . . increasing levels of

Figure 3: The Duck Curve Highlights the Need for Responsive Resources to Address Growing Ramping Needs



13 According to the CAISO's January 2021 Key Statistics, there are 12,697 MW of utility-scale solar (includes load-serving entities participating in California's market). SEIA's Q3-2020 fact sheet indicates that a total of 29,218 MW of total installed solar.

14 If solar resources were instead spread across an east-to-west orientation, the decline in solar output would occur over a longer period as the sun sets. This would allow operators more time to identify and "ramp-up" other dispatchable resources. A ramp refers to the generator responding to the change in load or to changes in output from other generators on the system. Daily net load ramps are especially prevalent during the spring and fall and are the result of growing amounts of distributed solar resources (primarily rooftop photovoltaic) that have caused overall system demand to decline during the middle of the day (the belly of the duck, when solar output is highest). Demand then rapidly increases in the late afternoon and early evening, when solar performance declines as the sun sets, causing net load to increase rapidly.

15 The duck curve demonstrates that the net load variability required fast-acting resources to "ramp-up" as much as 10,892 MW in 3 hours during the late-afternoon on February 1, 2016. CAISO Fast Facts: What the duck curve tells us about managing a green grid (2016).

16 CAISO/CPUC/CEC Final Root Cause Analysis. Executive Summary ES.2, pp. 3-5.

variable energy resources and behind the meter generation…" which contributes to the operational challenges associated with ramping capability.[17] The flexible ramping product promotes securing enough ramping capability in the 5-minute and 15-minute market to address the variability of wind and solar resources.[18] Unlike baseload generation, which provides relatively constant output, generation capable of ramping allows the CAISO to dispatch these plants to change output based on the changing needs of the system. These impacts are on the demand-side (due to the variability of distributed rooftop solar PV), as well as the supply side (due to changes in output from utility-scale wind and solar). Accordingly, the CAISO needs additional flexible resources capable of responding to increasingly variable system conditions. Flexible resources include the ability to perform the following functions:[19]

- Sustain upward or downward ramps
- Change ramp directions quickly (react quickly and meet expected operating levels)
- Respond to operator dispatch to maintain output for a defined period of time
- Store and modify time of energy use
- Start-up from a zero or low-electricity operating level with short notice (i.e., rapid start-up)
- Start and stop multiple times per day
- Provide accurate operating capability projections (i.e., the metered output from a unit matches the information provided to the system operator)

However, resources on the CAISO system with many of these characteristics have been taken out of service at a rapid pace. Approximately 9 GW of natural gas fired generation was removed from service within five years, including many combustion or combined-cycle plants that can respond rapidly to net load ramps.

Table 1: Capability of Different Power Generating Technologies to Provide Flexibility

Plant Type	Start-up Time	Max Change in 30 Seconds (%)	Max Ramp Rate (%/min)
Simple Cycle CT	10 - 20 min	20 - 30	20
Combined Cycle CT	30 - 60 min	10 - 20	5 - 10
Coal Plant	1 - 10 hr.	5 - 10	1 - 5
Nuclear Plant	2 hr. - 2 d	< 5	1 - 5

The ramp rates for most simple-cycle and combined-cycle gas turbine models are shown in **Table 1** and compared with other generating technologies.[20]

Meanwhile, the CAISO previous projections that the 3-hour ramp would grow to 13,000 MW by 2020, actually occurred on January 1, 2019, with an actual 3-hour ramp rate of 15,639 MW.[21] Despite these alarming trends, an additional 1.9 GW of dispatchable capacity was taken offline between June 2019 and June 2020.[22]

Replacement Capacity Must Address the System's Changing Reliability Needs

Generation retirements to meet RPS requirements or

17 CASO Revised Draft Final Proposal - Flexible Ramping Product, p. 3.

18 The Flexible Ramping Product requirements for the 15-minute market is usually higher than the requirement for the real-time dispatch, since there is uncertainty observed between the two market intervals, CAISO Energy Markets Price Performance, p. 72.

19 CAISO Fast Facts: What the duck curve tells us about managing a green grid, 2016, p. 2.

20 Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices (2020). (p.10).

21 Actual ramps have been as high as 14,360 MW during a 3-hour period, CAISO projecting 3-hour ramping needs to surpass 20,000 MW by 2022, p. 20. The net load is defined as system load minus renewable generation, including distributed generation (primarily rooftop photovoltaic), solar thermal, and wind power in California. The net load ramp also refers to the evening period of greatest ramping needs driven by the quickly diminishing solar output. Projections and actual data provided by the CAISO's Flexible Capacity Needs and Availability for 2020, p. 22.

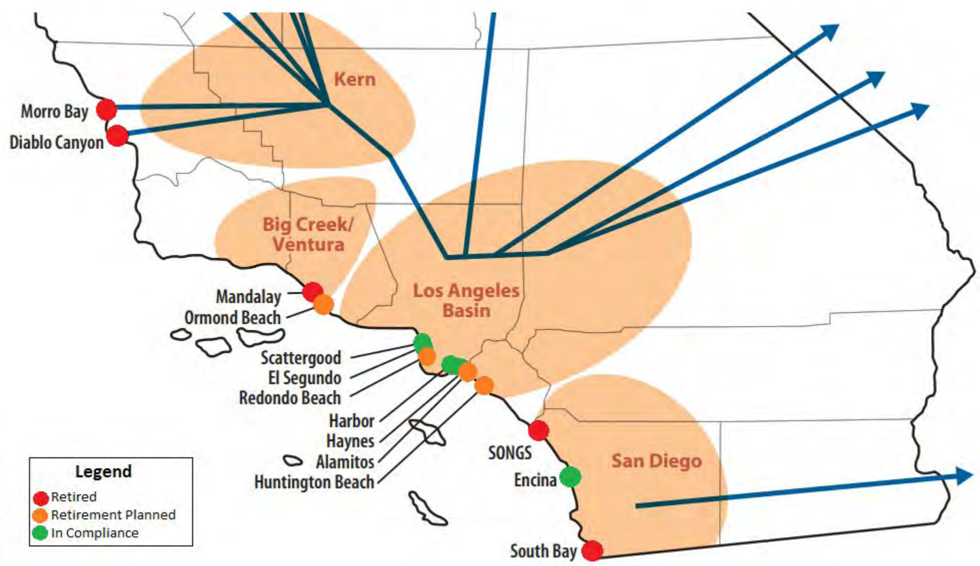
22 A total of 1,926 MW of dispatchable generation was taken out of service from June 1, 2019 to June 1, 2020, CAISO 2020 Summer Loads and Resources Assessment, p. 27.

comply with the California State Water Board's ongoing regulations that phase-out once-through-cooling (OTC), have occurred without securing enough adequate replacement capacity needed to address the operational challenges associated with increased system variability.[23] Former FERC Commissioner Cheryl LaFluer recognized this problem: "In the past three years, California has closed 5,000 MW of gas generation in anticipation of building 3,000 MW of battery storage that is still on the drawing board. In a heat wave, when every resource is needed, this gap in resources came home to roost."[24]

Former Energy Secretary Ernest Moniz also observed that "there is a shortage of [generating] capacity" and warned California policymakers that a combination of solar power and battery storage would not be able to fill the state's projected demand for electricity during the coming decade.

The ongoing retirements of nuclear capacity will significantly reduce the baseload capacity in Southern California. Concurrently, the most concentrated phase-out of gas-fired generation is occurring in the Los Angeles region.[25] To maintain system reliability, replacement capacity must be capable of providing essential reliability services to aid operators in managing growing net-load ramps caused by intermittent wind and solar. Transmission additions or reinforcements can further support the deliverability of resources across the system.[26] Of the 19 identified OTC plants (totaling 20,600 MW), more than half (10,400 MW) have been taken out of service since 2010. As shown in Figure 4, seven of the remaining plants are located near load

Figure 4: Southern California Generation Impacted by the Once-Through Cooling Phase-out Policy



23 Once-through cooling (OTC) technology causes adverse environmental impact by pulling large numbers of fish and shellfish or their eggs into a power plant's cooling system. Organisms may be killed or injured by heat, physical stress, or by chemicals used to clean the cooling system. Larger organisms may be killed or injured when they are trapped against screens at the front of an intake structure.

24 LaFleur, Cheryl A., What's Ailing California's Electric System?, Columbia University Earth Institute, September 2, 2020, https://blogs.ei.columbia.edu/2020/09/02/whats-ailing-californias-electric-system/.

25 The Los Angeles Department of Water and Power (LADWP) plans to retire three natural gas-fired power plants (1,211 MW) by 2025. EFI California Energy Study Outlines Ambitious Agenda to Maintain Global Leadership, p. 39.

26 "Deliverability" refers to a generator's ability to deliver its energy to load during different system conditions, including expected congestion caused by other generators' output, https://www.caiso.com/Documents/Jan2-2020-TariffAmendment-ImplementDeliverabilityAssessmentMethodologyEnhancements-ER20-732.pdf.

centers (Los Angeles and San Diego) providing reactive power, voltage support, inertia, and other essential reliability services to those areas. We expand on the importance of maintaining essential reliability services in the next section.

After the August events, then-President and CEO of CAISO, Steve Berberich highlighted the CAISO's requests to address projected capacity shortfalls needed to maintain established levels of resource adequacy.[27] The joint root cause analysis further recognized the need to "... address electric sector reliability and resiliency considering evolving policy goals of the state."[28] One proposed approach involves more cautious planning approaches for capacity retirements. In recognition of the recent capacity shortages highlighted by the August events, regulators at California's State Water Board extended OTC compliance deadlines and corresponding scheduled retirements of four power plants.[29] The continued availability of this generation will help maintain system reliability through 2023, as appropriate replacement capacity is identified and brought online.

The CPUC has also taken steps to address the concern regarding ongoing capacity shortages, indicating that "at least 3,300 MW of incremental system resource adequacy capacity and renewable integration resources would be needed by summer 2021."[30] The CPUC has contracted for 2,906 MW of Net Qualifying Capacity, scheduled to be online by August 1 of 2021, consisting primarily of intermittent resources and new storage technologies (**Table 2**).[31] Wind and solar resources have lower capacity factors and provide less consistent output compared to fully

Table 2: New Resources Expected – Sum of Net Qualifying Capacity (MW) by Load Serving Entity (LSE) and Technology Type

Sum of Net Qualifying Capacity (NQC), September NQC Megawatts (MW)	Online by 8/1/2021	Online by 8/1/2022	Online by 8/1/2023	Online post 8/1/2023	Grand Total
Contracted NQC MW	**2,388**	**840**	**481**	**267**	**3,977**
Investor-Owned Utility (IOUs)	*1,769*	*548*	*33*	*10*	**2,360**
Energy Storage	1,221	548	25	10	**1,804**
Solar plus Storage	494				**494**
Solar	38		8		**47**
Wind	16				**16**
Community Choice Aggregators (CCAs)	*584*	*274*	*427*	*257*	**1,543**
Solar plus Storage	152	81	269	257	**759**
Energy Storage	240	113	80		**433**
Solar	85	58	78		**221**
Wind	96	9			**105**
Geothermal		14			**14**
Small Hydro	12				**12**
Electric Service Providers (ESPs)	*35*	*18*	*21*		**74**
Solar	35	3	6		**43**
Solar plus Storage			15		**15**
Wind		15			**15**
Confidential or Uncontracted NQC MW	**518**	**156**	**693**		**1,368**
Grand Total NQC MW	**2,906**	**996**	**1,175**	**267**	**5,345**

27 August 17 briefing: "We told the CPUC 4,700 MW was needed through 2022 and that the gap started in 2020…Despite all that, only 3,300 MW was authorized for procurement, but that's not starting [until] 2021." Additionally, Berberich emphasized "…the situation we are in could have been avoided…For many years we have pointed out to the procurement authorizing authorities that there was inadequate power available."

28 CAISO/CPUC/CEC Final Root Cause Analysis. (p.75).

29 The State Water Resources Control Board amendment extends OTC compliance or phase-out dates at four fossil fuel power plants as follows: Compliance dates for Alamitos Units 3, 4, and 5 (1,165 MW), Huntington Beach Unit 2 (225 MW), and Ormond Beach Units 1 and 2 (1,516 MW) extended until December 31, 2023; the compliance date for Redondo Beach Units 5, 6, and 8 (850 MW) extended until December 31, 2021.

30 CPUC Rulemaking 20-11-003: Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021. (p.10)

31 CPUC Status of New Resources Expected, as of December 2020 (See slide 7).

dispatchable resources, especially during peak demand periods, as demonstrated during the August events.[32] Battery storage technology accounts for a small portion of the resource mix, with the CAISO currently operating 216 MW of installed capacity.

Battery Storage as Replacement Capacity Faces Remaining Operational and Market Hurdles

Relying primarily on battery storage additions to address near-term supply shortages poses reliability risks for several reasons. First, while the CAISO has demonstrated the ability to incorporate new technologies, operators still have limited experience with dispatching batteries on the system. Operators must contend with a learning curve associated with the deployment of a novel technology to develop an understanding of the behavioral characteristics and potential challenges associated with large-scale battery storage. Second, the CAISO has identified that the performance and effectiveness of battery storage systems are highly dependent on their location. Battery systems located near load centers can face challenges in accessing available transmission to ensure they are able to be charged and available when called upon.[33] Alternatively, batteries located long distances from load centers may face transmission congestion when attempting to inject power where needed. Related market performance issues are also still in development. A CAISO stakeholder initiative is underway to determine appropriate locational price signals to promote battery charging and availability windows that align with system needs.

Finally, it is important to recognize that even the most advanced batteries can provide continuous, stable energy output for limited durations (approximately four hours).[34] Extreme heat waves can last for days. CAISO's Steve Berberich has suggested that as much as 15,000 MW of fast-acting batteries (of different duration levels and various technologies) would be needed for California to achieve 100 percent renewables by 2045. Ongoing measures by the CAISO and the CPUC to monitor the impact of additional battery storage will help ensure that this technology can be reliably added to California's system to help offset the loss of dispatchable generation.

Reliance on Imports from Neighboring States

The transformation of California's system towards 100 percent carbon-free resources has also increased dependence on imported power from neighboring states. On average, the state relies on imported power to serve approximately a quarter of its annual electricity demand. However, maximum net imports during high-load conditions actually declined from 11,147 MW in 2017 to 8,792 MW in 2019, despite the ongoing expansion of the Western Energy Imbalance Market (EIM).[35] This trend indicates that the availability of imports needed for high load periods could be at risk during a time when CAISO may be most dependent on them.[36]

While the EIM has helped to promote coordinated resource sharing by allowing participants to access CAISO's real-time market, notable benefits won't be recognized until participants can also bid in the

32 According to the CAISO/CPUC/CEC Final Root Cause Analysis, "…with today's new resource mix, behind-the-meter and front-of-meter (utility-scale) solar generation declines in the late afternoon at a faster rate than demand decreases. These changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability…" (p.4). Resource performance will be further discussed in the next section.

33 Transmission congestion can occur in load centers that make it difficult for batteries to charge during certain periods, since lines are already loaded to serve demand. Congestion can also make it difficult for batteries to inject power in some areas of the system.

34 Whereas existing storage technology can provide longer durations, the four-hour output requirement is a function of the RA rules. Specifically, the rules only require that a storage facility produce at least four hours of output to be classified as RA.

35 The EIM participants across the Western Interconnection can bid into the CAISO's real-time market to buy and sell power close to the time electricity is consumed. It offers system operators real-time visibility across neighboring grids. The ability to share a larger pool of resources can support resource adequacy needs by increasing balancing capabilities and reducing costs. "High-load conditions" are described by the CAISO as load that is "equal to or greater than 43,000 MW," CAISO/CPUC/CEC Final Root Cause Analysis, p. 4.

36 CAISO/CPUC/CEC Final Root Cause Analysis, p. 4.

day-ahead market. This would allow entities throughout the west to efficiently plan and commit resources based on price signals. The day-ahead commitment will also help the CAISO identify transfer capability, system congestion, and potential resource shortages with more time to secure additional generation. This ongoing stakeholder initiative to unlock such benefits has been under discussion for several years due to unresolved concerns of some EIM members.

Despite the potential progress toward an extended day-ahead market or a Western RTO, the limitations of the existing transmission infrastructure are also a concern. During the August events, transmission paths across both the California-Oregon Intertie and Nevada-Oregon Border were heavily congested, as "…transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint."[37]

Importing additional power into California will likely require transmission upgrades or additions, assuming that neighboring states are willing to offer these imports in the future. Entities across the west could begin to withhold exporting power to meet decarbonization policies in their own state. For example, Washington State's RPS of 100 percent renewables by 2045 may limit hydro exports to California. Similarly, plant retirements in Arizona, Nevada, and New Mexico may further diminish the CAISO's current access to out of state resources.

The importance of reliance on imports from neighboring states necessitates continued collaboration to better understand how individual state policy goals will impact transfer capability. In the northeast, the Integrated Clean Capacity Market (ICCM) puts individual state energy policies at the center of a revised resource adequacy market, while modernizing existing resource adequacy constructs throughout the PJM Interconnection. Specifically, the ICCM promotes a flexible market framework to accommodate states at varying levels of progress toward a decarbonized electric system so that the energy goals of some states can be supported without imposing any costs on other states with differing policy priorities.

In the near-term, the CAISO may also consider modifying the assumptions for projected imports in their seasonal assessments, which currently assume the inclusion of non-RA imports, despite the risk that this energy may not be available during extreme weather events throughout the region. Future projections of import availability could also include scenarios that examine increased limitations due to potential transmission constraints and/or EIM market rules that impose transfer limits (e.g., flexible ramping sufficiency test).[38]

Limitations of Demand Response

The preliminary root cause analysis partially addresses the issue of procuring additional resources through a recommendation that the CPUC and CEC collaborate "to expedite the regulatory and procurement processes to develop additional resources that can be online by 2021. This will most likely focus on resources such as demand response and flexibility. . . "[39] In November 2020, the CPUC opened a proceeding to address reliability needs for the 2021 summer. Three of the four CPUC proposals supported demand-side solutions.[40]

Demand response and other demand-side management programs have traditionally been used to reduce peak capacity investment needs by reducing electricity consumption during emergency events. However, demand response programs vary significantly in how they are controlled and dispatched by the system operator. Demand response performance is also a concern, as well as limitations on the number of times a program participant can be called upon to respond per season or year. In evaluating

37 Ibid, p. 48.

38 CAISO/CPUC/CEC Final Root Cause Analysis. "On August 14 and 15, the CAISO failed for less than two hours on each day and a cap was imposed on the transfer limit into the CAISO." See B.3.4 Energy Imbalance Market, pp. 130-131.

39 CAISO/CPUC/CEC Preliminary Root Cause Analysis, Preliminary Recommendations ES.5, p. 15.

40 CPUC Press Release, "CPUC Acts to Establish Policies and Procedures for Ensuring Grid Reliability during Extreme Weather Events," p. 1.

these proposals, it will be important to recognize the flexibility limitations associated with demand response, particularly in the inland portion of the state, where there is less tolerance for cutting air conditioning or temporarily suspending the operation of agricultural pumping stations during the summer months.[41] For this reason, demand response programs need to complement, not substitute for "iron in the ground" capacity.

Supplemental Reliability Procedures

Despite the ongoing system retirements described above, the system operator holds two important backstops to address unresolved resource adequacy deficiencies and/or meet specified reliability needs. The first backstop, the capacity procurement mechanism (CPM), provides an economic incentive to keep generators online. The CAISO tariff provides two compensation options. The CPM resource can either receive compensation based on its capacity bid price up to the CPM soft offer cap (set at $6.31/kw-month),[42] or the CPM resource can offer capacity at a cost above the soft offer cap. Offering capacity above the cap requires the provider to file a justification for the higher price with the FERC. Both options allow the CPM resource to retain all future revenues earned in the CAISO markets.[43] The CPM provides a useful tool for incenting retiring resources to remain online, although the CAISO may need to revisit the soft offer cap in 2021.[44] Future revisions to the program will likely be informed by the August events, including the impacts of 1,900 MW of dispatchable generation taken out of service between October 2019 and January 2020.[45]

The second reliability backstop allows the CAISO to designate certain power plants as Reliability Must-Run (RMR).[46] This delays any scheduled retirements or recalls mothballed units when needed to meet the established reliability criteria. Prior to the summer of 2020, the CAISO designated three natural gas units (totaling approximately 125 MW) to remain available for the 2020 summer.[47] Even with the extended availability of these RMR units, system operators did not have enough controllable resources to serve load during the August supply shortages.

While these backstop mechanisms are effective, regulators might also wish to examine policies that further promote the mothballing of certain plants. Similar to the RMR approach, this would involve collaborating with the CAISO to identify units that would remain idle, but not decommissioned, to support compliance with environmental requirements, but available to address future capacity shortages and local resources adequacy concerns. Similar approaches have been introduced in Texas, where NRG Energy restarted a 385 MW natural gas-fired combined-cycle plant that had been mothballed since 2016, for the 2020 summer season, partly to address tight supply conditions in ERCOT. Germany, a country with decarbonization goals similar to California's, used a similar approach to return approximately 1.4 gigawatts of mothballed

41 The CPUC, CEC, and the CAISO assign derates to DR programs based upon the results of DR load impact studies and program dispatch requirements (e.g., price, demand, location, duration).

42 This cap is based on the fixed operations and maintenance costs, ad valorem taxes, and insurance costs of a reference unit, plus a 20 percent adder to that total cost. See FERC's May 29, 2020, Order Accepting CAISO Tariff Revisions.

43 A 2019 stakeholder initiative to increase the soft offer cap was rejected in mid-2020 when it was determined that the current soft offer cap was still relevant to the existing grid composition.

44 A higher offer cap may further incent additional generation, or incent existing generators to remain operational, instead of retiring.

45 Including: Alamitos units 1, 2, 6, 7 (844 MW); Redondo unit 7 (493 MW); Inland Empire Energy Center Unit 1 (340 MW); and Huntington Beach Unit 1 (225 MW).

46 Local Reliability Criteria are unique to the transmission systems of each of the Participating Transmission Owners. Local Reliability Criteria and related Local Capacity Requirements reflect CAISO, NERC, and Western Electricity Coordinating Council (WECC) Planning Standards, as well as WECC Operating Criteria (OC) Path Ratings and System Operating Limits (SOL).

47 These units included Greenleaf Unit 2 (47 MW), the E.F. Oxnard plant (48 MW), and Channel Islands Power plant (27 MW).

gas plants to service in 2020.[48] Introducing market mechanisms to keep certain capacity idle but operable could help California meet carbon emission reduction goals, while still maintaining enough standby capacity for periods when system reliability is threatened. Examples of this process include ERCOT's Operating Reserve Demand Curve, PJM's capacity markets, ISO-New England's competitive forward capacity auctions (used competitive forward capacity auctions, and other market structures for securing system supply to meet projected resource adequacy needs.

The next section examines ongoing efforts by the CPUC and the CAISO to enhance their infrastructure planning approaches. We also explore potential opportunities for regulators and operators to more accurately capture the changing reliability characteristics (and potential risks) associated with an increasingly variable system.

Addressing Resource Adequacy Needs through Enhanced Planning Metrics

The final root cause analysis recognized that "changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability [and] . . . additional work is needed to ensure that sufficient resources are available to serve load during the net peak period and other potential periods of system strain."[49]

In order to understand the additional work that is underway, it is important to identify the multiple participants that share responsibility for infrastructure planning in California. These entities and planning processes have remained largely intact since the late-1990s, with key responsibilities summarized in **Table 3.**[50]

California's infrastructure planning processes necessitate close collaboration with – and input from – both the CAISO and CEC. System-wide and local reliability requirements, as well as flexibility needs, are ultimately developed within the CPUC's resource adequacy (RA) program.[51] Established after the 2000-2001 California Energy Crisis, this program creates requirements for jurisdictional LSEs to maintain resource availability through contractual obligations. The planning reserve margin (PRM) is a critical element of the RA program and is used to

Table 3: Primary Entities Involved in California's Resource Planning Processes

CPUC	Jurisdictional LSEs	CAISO	CEC
Manages the state's Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP). This process is designed to ensure that the electric sector meets its GHG reduction targets while maintaining reliability (with a resource adequacy program) at the lowest possible cost. This process involves modeling the system topology and market dispatch results to determine the appropriate resource portfolio needed to meet policy goals.	Must submit individual IRPs (based on the parameters in the IRP-LTPP) for CPUC review and approval.	Develops an annual Transmission Planning Process used to identify needed transmission upgrades and inform the CPUC's IRP-LTPP process.	Develops long-term energy demand forecasts as part of their Integrated Energy Policy Report (IEPR). The CEC's IEPR demand forecasts are inputs into the CPUC's long-term resource planning process and the short-term annual resource adequacy process, used to establish RA procurement obligations for LSEs.

48 Germany met over 40 percent of the country's power consumption with renewables in 2019, exceeding the 2020 target of 35 percent one year ahead of time. The government is now taking aim at 65 percent by 2030, as stated in its Climate Action Programme 2030.

49 CAISO/CPUC/CEC Final Root Cause Analysis, p. 5.

50 A detailed process is available within the CPUC's Long-Term Procurement Plan History and Related Process Documentation. (See Process Diagram (v3.8). While the terminology has changed since the release of the v3.8, the CPUC has not released an updated diagram.

51 CPUC Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP).

establish monthly requirements to ensure LSEs procure sufficient resources for the CAISO to reliably operate the system. The PRM targets also inform the commission's procurement decisions.

Limitations of Existing Resource Adequacy Metrics

As discussed earlier, jurisdictional LSEs must procure enough capacity to serve the peak demand forecast, plus a 15 percent PRM.[52] To demonstrate this concept, we examine California's planning reserve margin leading up to the August 2020 events.[53] From a seasonal planning perspective, the CAISO system appeared to have had adequate planning reserves going into the summer of 2020. The CAISOs projected 46,903 MW of capacity to be available in August, with a 1-in-2 net peak load forecast of 40,370 MW. Using NERC's reserve margin method would have indicated that this was a healthy reserve margin of 17.1 percent, excluding the projected 1,339 MW of demand response capability:[54]

$$\begin{matrix}\textit{CAISO}\\ \textit{Reserve}\\ \textit{Margin}\end{matrix} = \frac{\text{Peak Resources–Forecasted Load}}{\text{Forecasted Load}} = \frac{46{,}903-40{,}037}{40{,}037} = 17.1\%$$

The reserve margin metric provides a snapshot of system adequacy and reliability at the highest forecasted demand. It is based on the important assumption that system reliability will be maintained throughout all other hours of the analysis period (planning horizon). Based on traditional planning criteria, a 17.1 percent margin (well-above the 15 percent PRM target) indicated that the system had adequate planning reserves for the 2020 summer season. However, the current PRM target of 15 percent was established in 2004, based on "analysis of then-current market data and forecasts of how the market was expected to evolve due to anticipated increases in renewables, energy efficiency, demand response, and other factors."[55] A significant finding of the final root cause analysis of the August events was that "resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging."[56]

California's PRM targets are based on Loss of Load Expectation (LOLE) modeling, designed to measure the reliability of an electric system, based on assumptions that incorporate a variety of conditions.[57] The PRM targets are ultimately dependent on the level of system reliability that the CPUC determines to be acceptable for the state. Currently, PRM targets are developed based on an annual LOLE target ranging from 0.095 to 0.105. This roughly translates to 1 loss of load event over a 10-year period. The CAISO's current LOLE assumptions combine multiple loss-of-load events occurring within one day into a single event (for purposes of counting events toward a reliability targets).[58] Accordingly, the analysis fails to capture a series of smaller events that could, in aggregate, impact system reliability.

Annual LOLE Target ≈ .01 → **PRM Target = 15%**

The LOLE analysis and the more commonly referenced reserve margin have both been heavily relied-upon by the industry for decades. Although useful and informative, these metrics must be examined in the proper

52 Like RA, IRP modeling is also based on the CEC's adopted 1-in-2 demand forecast plus a 15 percent PRM.

53 This example is a simplistic example examining the entire CAISO system. PRM requirements apply to individual of LSEs.

54 NERC (the North American Electric Reliability Corporation) defines the reserve margin as "…the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage" (p.35). Available demand response capability: CAISO 2020 Load and Resources Report, p. 5.

55 CPUC Rulemaking 19-11-009. Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations, pp. 18-19.

56 CAISO/CPUC/CEC Final Root Cause Analysis, pp. 1, 4, 38.

57 CPUC 2020 ELCC Methodology Working Group – Review of ELCC Study improvements, September 2019.

58 CPUC Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies, p. 11.

context. Baseball enthusiasts don't rely on a single statistic to evaluate a player. They examine the player's on-base percentage (OPS), runs batted in (RBI), home runs (HR), stolen bases (SB), and dozens of other measures of performance in various aspects of the game. Measuring resource adequacy and system reliability should be no different – especially considering the significant changes on California's system during the past decade.

Increasingly, the LOLE and deterministic reserve margin approaches do not fully capture the level of resource adequacy for systems with large amounts of intermittent wind and solar. This is because the LOLE methodology was initially developed to measure the resource adequacy of systems with mostly controllable resources (e.g., large hydro, fossil-fired, and steam-powered generators) serving relatively predictable load patterns. Because these resources were controllable by system operators, planners made procurement decisions based largely on serving changing demand projections. Today, system operators also have reduced control over the supply side due to growing levels of utility-scale wind and solar that is variable in nature (i.e., operators cannot increase wind speed). On the demand side, load projections have also grown in complexity with the rapid deployment of distributed solar PV, which causes net-load to fluctuate based on cloud cover and other factors that are outside the system operator's control.

The CPUC took action to address these concerns prior to the 2020 summer supply shortages. Their June 2020 order initiated a review of the PRM target range, authorizing the commission's Energy Division to facilitate a working group to develop a set of assumptions for use in an LOLE study.[59] After the August events, the commission also opened an Emergency Reliability rulemaking to prioritize resource adequacy and resource procurement for the 2021 summer season. Several entities involved in California's resource planning efforts responded, including CAISO:

> The CAISO greatly appreciates the Commission's efforts to increase resource adequacy procurement to address summer 2021 reliability. Importantly, this incremental procurement should be tied to an increase in the planning reserve margin (PRM) to 20 percent for two critical reasons. First, increasing the PRM will ensure new resources do not substitute for existing capacity, thus leading to little or no net increase in the resource adequacy resource fleet. Second, increasing the PRM will allow the CAISO to use its capacity procurement mechanism (CPM) to backstop to the higher PRM.[60]

The CAISO subsequently revised its recommendation to 17.5 percent.

Increasing the PRM will improve short-term resource adequacy by requiring jurisdictional LSEs to secure additional reserve capacity.[61] The CPUC will ultimately need to examine the cost implications associated with a higher PRM requirement. The commission might also consider developing a PRM range with localized requirements to address areas facing insufficient resources or transmission constraints. Local reserve requirements designed to co-optimize the energy dispatch and reserve schedules could promote local market prices that reflect constraints based on reserve availability in a sub-area.[62]

The Case for Hourly Modeling

Because LOLE and reserve margin analyses are becoming a smaller part of the resource adequacy puzzle, the CPUC recognized that "a LOLE value of 0.1, which is a direct translation of the decades old industry "one day in ten years" standard, may warrant

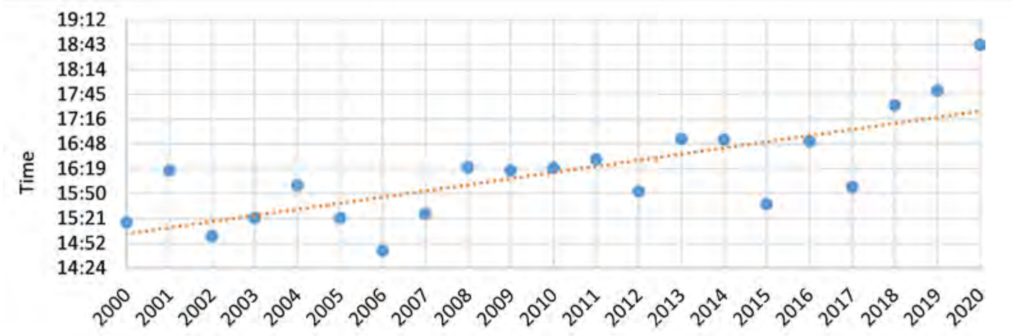
59 CPUC Decision 20-06-031. Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations, pp. 4, 21, 89.

60 CAISO Responses to Ruling Proposals and Questions. Response to question 5, p. 3.

61 Any change in the PRM would not apply to non-firm (independent power producers) capacity, as the CPUC will likely require all qualifying resources to provide qualifying RA.

62 William Hogan has suggested this approach for ERCOT, Harvard Electricity Policy Group: Priorities for the Evolution of an Energy-Only Electricity Market, 2017.

Figure 5: The Summer Peak Is Occurring Later in the Day



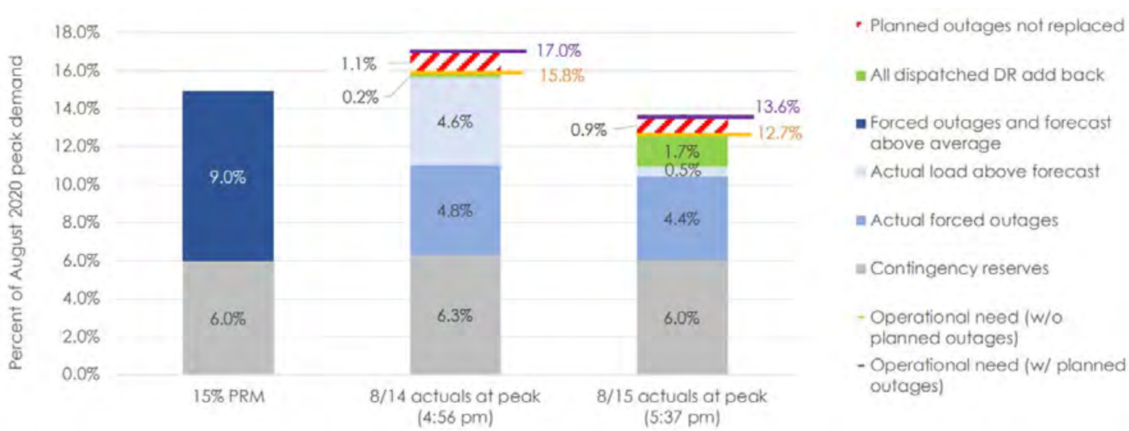
reconsideration in light of the sophisticated hourly models and advanced computing available now. . . "[63] Hourly modeling is necessary to address the changing load patterns, which have pushed seasonal system peaks further into the evening (**Figure 5**).[64]

Figure 6 demonstrates that the CAISO system was able to reliably serve load during the both peaks on August 14 and 15 and "although a PRM comparison is informative, the rotating outages both occurred after the peak hour..."[65] Hourly modeling can provide important insights for planners, allowing them to identify and prepare for potential reliability risks that occur outside of the peak period.

Resource Adequacy Accountability

The final root cause analysis recommended increasing RA requirements for LSEs to address extreme weather events.[66] However, as the number of CCAs and smaller electric service providers (ESPs) continues to increase, it's important to ensure these entities are providing sufficient levels of RA capacity. CCAs and ESPs currently provide 26 percent of the load formerly served by the state's three largest investor-owned

Figure 6: August 2020 PRM and Actual Operational Need during Peak



63 CPUC Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies, p. 11.

64 Figure created by NRRI staff using the following CAISO data: CAISO historic peak loads; CAISO Key Statistics – August 2020.

65 CAISO/CPUC/CEC Final Root Cause Analysis, p. 43.

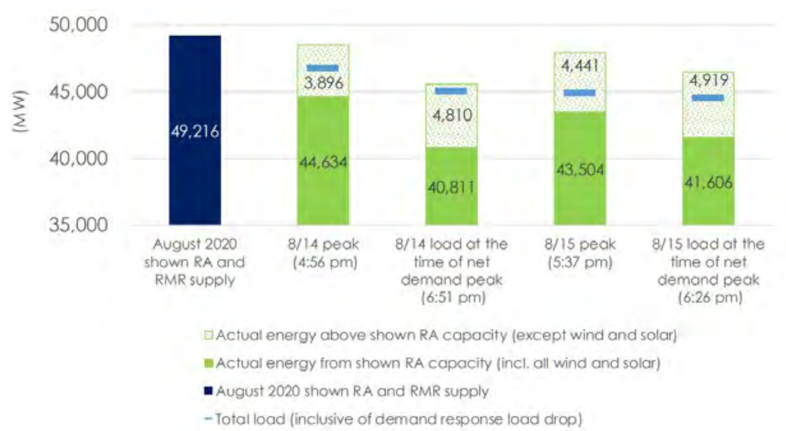
66 Ibid, pp. 91-92.

utilities (IOUs).[67] The CPUC has warned that this trend contributes to a state-wide planning process that is less consolidated and "creates a more complex paradigm for assessing both system reliability and whether California is on-track to achieve its climate goal. While CCAs and ESPs are subject to the same annual RPS Procurement Plan (RPS Plans) requirements as required by the IOUs, recent RPS Plans show that many CCAs and ESPs continue to provide minimal information in their RPS Plans… inadequate procurement planning may cause LSEs to not meet the state's requirements, resulting in negative implications for reliability of the power system."[68] As CCAs continue to expand their generation portfolios and customer base, these entities must be increasingly involved in planning activities and held accountable for meeting system reliability requirements.[69] The CPUC plans to address challenges during the coming years within their IRP-LTPP program by possibly introducing enforcement penalties for CCAs and ESPs that fail to provide them with adequate planning data.[70]

Developing More Robust Resource Adequacy Metrics

Recognizing these shortfalls, system planners across the country have made significant progress in improving resource adequacy metrics, moving away from deterministic approaches and toward a greater focus on stochastic and probabilistic methods. One of the recommendations of the final root cause analysis called on the CAISO to coordinate with the CPUC and other stakeholders to "refine the counting rules as they apply to hydro resources, demand response resources, renewable, use limited resources, and imports."[71] The analysis further indicated that the actual output of RA and reliability-must-run (RMR) capacity did not reflect their projected availability (**Figure 7**).[72,73]

Figure 7: August 2020 Shown RA and RMR Capacity vs. August 14 and 15 Actual Energy Production



The CPUC and CAISO will benefit by further examining these discrepancies and updating the underlying assumptions used in future RA and RMM projections. In terms of actual performance by resource type, the final root cause analysis further reported that the natural gas generation fleet collectively experienced between 1,704 MW to 2,371 MW of forced outages, more than any other resource.[74] These outages translate to between 4-6 percent of the natural gas generation fleet that was not already scheduled to be

67 CCAs allow for communities to join together to choose their electric provider and sources of electricity.

68 *CPUC 2019 RPS Annual Report to the Legislature,* p. 54.

69 According to the CPUC, "load allocated to CCAs in the year ahead process went from two percent of the peak in 2016 to 25 percent of the peak in 2019. Energy Division anticipates 'this trend towards disaggregation of load to continue…'" CPUC Rulemaking 17-09-020, p. 21.

70 Additional information on the CPUC gap analysis that addresses CCA RA shortfalls is available here: California Customer Choice Project - Choice Action Plan and Gap Analysis.

71 CAISO/CPUC/CEC Final Root Cause Analysis, p.72.

72 Ibid, p. 110.

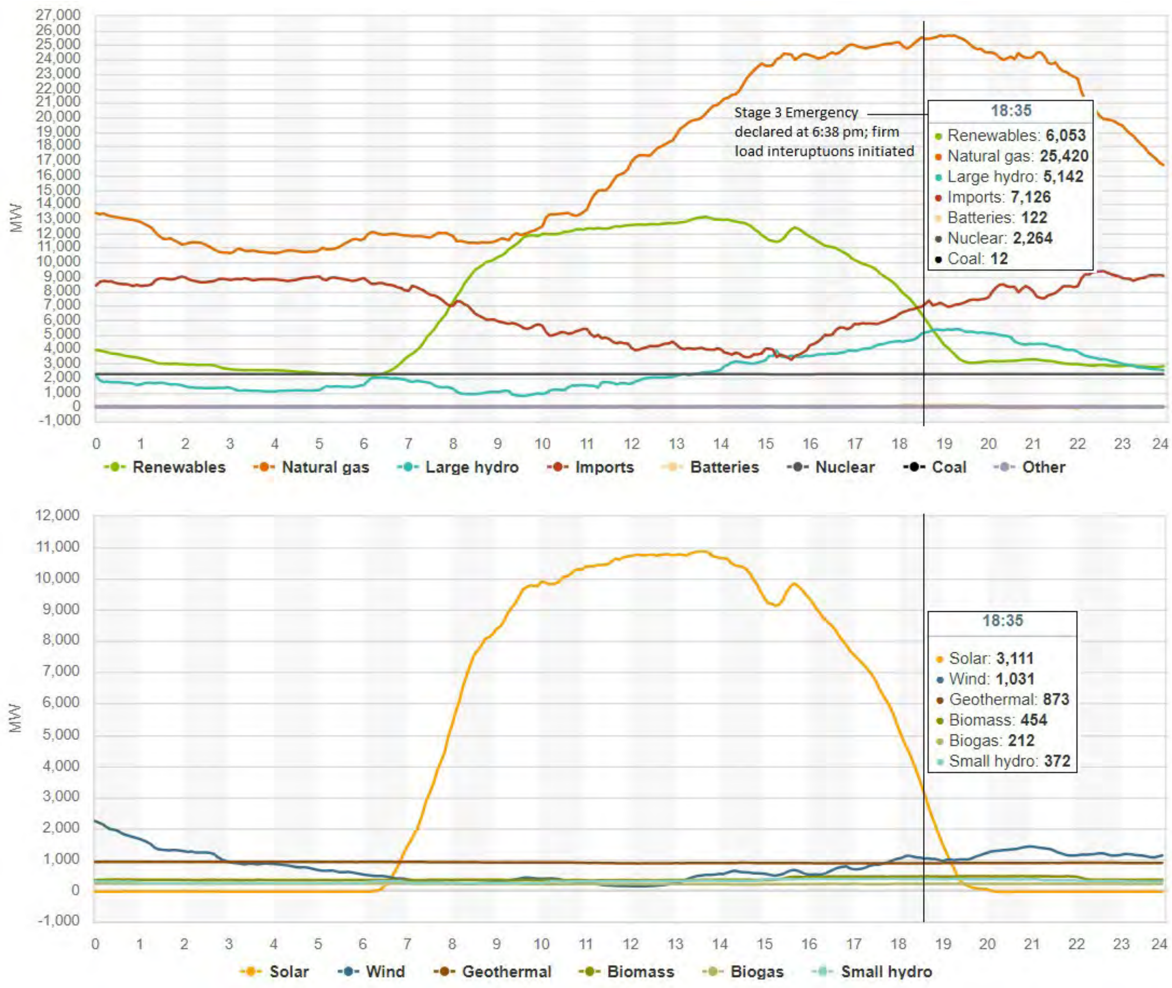
73 Assumes all wind and solar counts as RA supply; CAISO/CPUC/CEC Final Root Cause Analysis, p. 110.

74 CAISO/CPUC/CEC Final Root Cause Analysis, p.87. (Includes derates to individual units, as well as unit outages.)

out of service. The natural gas generation fleet served over half of the state's load when the Stage 3 Emergency was declared at 18:38 on August 14.[75] During the same period, actual output from 24,016 MW of installed renewable resources served 6,053 MW (14.3 percent) of load.[76] Renewable output (particularly solar) actually decreased by 1,064 MW during the next 15-minutes as net load continued to increase, finally peaking at 18:51. In contrast, output from dispatchable resources, including natural gas and in-state large hydro, increased by 321 MW during the same 15-minute period, serving 73.1 percent of net load during the peak. Although renewable resources performed as expected, their overall contribution during the peak period further highlights the performance attributes of each resource—especially during extreme weather events (**Figure 8**).

The CAISO has already begun using more sophisticated approaches for assessing resource adequacy with increased renewables, including the Unloaded

Figure 8: August 14, 2020 Total Supply Performance at 18:35 (Beginning of Stage 3 Emergency)



75 Assumes the California Energy Commissions 2019 Installed In-State Electric Generation Capacity (latest available), with a natural gas generation fleet totaling 40,382 MW. Natural gas performance at 18:50-18:55pm (5-minute market) was providing 25,539 to serve the net demand peak (42,237) at 18:51 p.m. on August 14. See the CAISO supply trend data for August 14, 2020. Demand data: CAISO/CPUC/CEC Final Root Cause Analysis, pp. 44-45.

76 CAISO Key Statistics – July 2020. See Installed renewable resources (as of 8/01/2020), p. 3.

Capacity Margin (UCM). This metric measures the amount of surplus resources or capacity that can respond within 20 minutes or less during the forecasted demand during a specified interval.[77] Similar to a reserve margin, the UCM metric is expressed as a percentage, but it is more comprehensive, because it captures multiple hours (beyond the peak period). The CAISO's 2020 Load and Resources Assessment demonstrated that the median UCM for all 2,928 summer hours (modeled within each of the 2,000 summer scenarios), was 41.3 percent.[78] Levels of UCM above the operating reserve requirement for any given hour (typically around 6 percent) indicate the amount of capacity projected to be available to address system contingencies (beyond the NERC operating reserve requirement). The Minimum Unloaded Capacity Margin (MUCM), the lowest UCM from each of the 2,000 scenarios modeled, is used to establish the probability of various events occurring. Continuing to enhance stochastic production simulation tools will enhance the CAISO's ability to assess the widest array of load, wind, and solar outages, as well as understand historic performance profiles. This tool can also provide planners with a distribution of potential outcomes and probabilities. The ongoing Resource Adequacy Enhancements initiative will depend on input from the CPUC and other stakeholders to determine the appropriate reliability criteria, as well as the quantity and attributes needed to address existing resource portfolio deficiencies.

NERC, the FERC-designated electric reliability organization (ERO) in the United States, has codified multiple reliability attributes provided by different resources. These essential reliability services (ERS) include frequency and voltage support, as well as ramping and balancing capability. The ERS capabilities and operating behaviors of conventional generators are well-documented, compared to those of relatively new wind and solar technologies. NERC states that "changes in the generation resource mix and technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability, thereby raising issues that need to be further examined."[79] Measuring a system's level of ERS offers a more comprehensive approach to resource adequacy by examining other important reliability attributes. NERC indicates that overall system reliability can be maintained…

> as the resource mix evolves, provided that sufficient amounts of essential reliability services are available.[80] [NERC further emphasizes that]. . . merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the electric grid to have resources with the capability to provide sufficient amounts of these [essential reliability] services and maintain system balance.[81]

Although wind and solar resources can provide certain types of ERS (e.g., synthetic inertia), there must also be adequate levels of frequency response, ramping capability, inertia, and reactive support for voltage control. Operators rely on these essential reliability services to operate the system under a variety of conditions, including extreme weather events that can cause generator outages and increase variability in wind and solar output.

Conclusion

The contributing factors leading to the August 2020 reliability events in California have been examined, and the lessons-learned from the events can be applied to other states that are introducing policies

77 CAISO, 2020 Load and Resources Assessment, p. 6.

78 Taking into account the unloaded capacity margin for all of 2,928 summer hours (June 1 through September 30) within each of the 2,000 summer scenarios. According to the 2020 Load and Resources Assessment: "The unloaded capacity refers to any portion of online generation capacity that is not serving load and offline generation capacity that can come online in 20 minutes or less to serve load as well as curtailable demands such as demand response, interruptible pumping load, and aggregated participating load that can provide non-spinning reserve or demand reduction. The unloaded capacity includes operating reserves the system procures. The Unloaded Capacity Margin (UCM) is the excess of the available resources, within 20 minutes or less, over the projected load expressed as a percentage on an hourly basis."

79 NERC Sufficiency Guidelines White Paper, December 2016, p. iv.

80 Ibid, p. vii.

81 Ibid, p. iv.

aimed at rapidly decarbonizing the grid, often leading to the addition of intermittent and behind-the-meter resources. These include:

- Systems with increasing amounts of intermittent resources (e.g., wind and solar) will require additional modeling and stochastic metrics that can provide a more complete measure of resource adequacy and help identify associated reliability risks.
- The continued development of advanced reliability metrics, including those that examine risks beyond the peak hour, can inform policy and regulatory decisions to promote the reliable transformation to a cleaner system.
- Existing planning processes and reliability constructs need to better identify the system impacts of retiring resources, examining the status of essential reliability services on the system, including ramping capability, frequency response, and inertia.
- Future projections of RA availability and ELCC values should be reviewed and modified to incorporate resource performance during the August events.[82]
- Regionalization can help promote reliability by efficiently pooling resources; however, increased coordination will be needed to recognize the impacts of transmission constraints and individual state policy goals.

These approaches can inform policy makers and state regulators charged with balancing the responsibilities of managing RPS compliance and resource adequacy requirements.

82 "Based on further analysis by the DMM, the actual production of all resources shown as RA or obligated under an RMR contract was sufficient during the peak but insufficient during the net demand peak period to meet all load, losses and spinning and non-spinning reserve obligations on August 14 and 15," CAISO/CPUC/CEC Final Root Cause Analysis, pp. 109-110.

About the Authors

Elliott J. Nethercutt is a Principal Researcher at NRRI. He has worked on market design enhancements at the California Independent System Operator (CAISO), developed reliability assessments at the North American Electric Reliability Corporation (NERC), and supported transmission siting efforts and smart grid funding programs at the U.S. Department of Energy. Elliott earned a bachelor's degree in economics from the University of Colorado and a master's degree in applied economics from the Johns Hopkins University.

Chris Devon is a Director of Market Intelligence at Customized Energy Solutions. He provides regulatory and market design policy coverage on the California Independent System Operator (CAISO) and wholesale electric markets in the West. He has also worked on resource adequacy and emerging technology policy enhancements at the California Independent System Operator (CAISO). Prior to his work in California, he advised the Michigan Public Service Commission (MPSC) on energy market design and resource adequacy policy matters. Chris earned a bachelor's degree in economics from Michigan State University.

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The National Regulatory Research Institute (NRRI) was established in 1976 as the research arm of the National Association of Regulatory Utility Commissioners (NARUC). NRRI provides research, training, and technical support to State Public Utility Commissions. NRRI and NARUC are co-located in Washington, DC.

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MARCH 2021

Regulatory Questions Engendered by the Texas Energy Crisis of 2021

Dr. Carl Pechman and Elliott J. Nethercutt

1. Introduction

The February extreme cold weather event in Texas resulted in significant electric outages across the Electric Reliability Council of Texas (ERCOT) system. The disruptions contributed to the loss of human life, with significant economic harms in the aftermath. Understanding the regulatory dynamics, markets, and economics that resulted in widespread power outages across the state will be instrumental for determining whether the price of power that resulted from the crisis warrants modification. Further, understanding the causes of the problem will facilitate redesigning market rules, regulations, and other protocols. It is important to note that the market design in Texas has evolved over many years and that the solutions to the issues raised by the crisis will require the cooperation of many stakeholders.

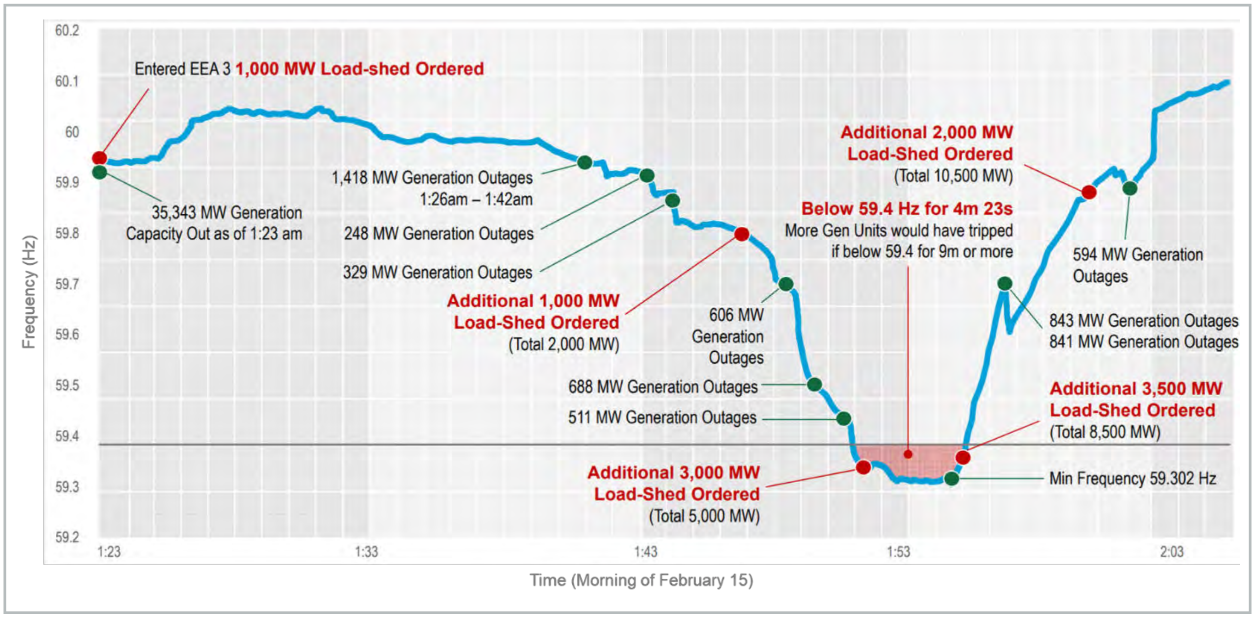
The purpose of this paper is to pose regulatory questions that will facilitate the understanding of the underlying regulatory actions and market behaviors that affected the likelihood of this catastrophic event. Although a thorough investigation and root cause analysis will be required to formulate complete answers, NRRI offers these perspectives and discussion about the role of the current regulatory regime and market design to further promote resource adequacy, resilience, and operating security for a system that has experienced an increasing number of extreme weather events during the past two decades. In presenting these questions, we explain the underlying rationale behind them. The questions elucidate a number of themes: 1) inherent market design flaws, 2) insufficient regulatory oversight, 3) market manipulation, and 4) the distinction between reliability and resilience in designing and managing the electric market.

2. Why Did ERCOT Nearly Black Out?

The cold snap began on February 12, 2021 and resources across the system started to fail over the following days, while loads remained high. At 7:06 p.m. (CST) on the 14th, ERCOT hit a winter peak of 69,222 MW. The system operated without incident through the record winter peak. By early on the 15th, system conditions deteriorated rapidly as an additional 20 GW of generation tripped offline (in addition to the 25 GW that were already out). ERCOT declared an Energy Emergency Alert (EEA-3)[1] at approximately 1:20 a.m. Subsequently, the system operator began efforts to maintain system stability through a series of load sheds. Despite coming within minutes of a cascading blackout, the system operator demonstrated what will likely be studied as a textbook example of managing a power system through severe operating conditions. **Figure 1** demonstrates these developments through a detailed timeline, showing how frequency dropped as prolonged extreme weather and sustained high demand resulted in increased generator outage rates. When frequency drops below established operating limits, generators have protection systems that automatically disconnect the unit from the grid to avoid equipment damage. It is important to recognize that demand-side actions (load curtailments that began at 1:45 a.m.) ultimately allowed the system to recover from dangerously low frequency and avoid an ERCOT-wide blackout.

1 An Energy Emergency Alert-3 (EEA-3) is declared when operating reserves cannot be maintained. See, *ERCOT's use of Energy Emergency Alerts*, http://www.ercot.com/content/wcm/lists/164134/EEA_OnePager_FINAL.PDF

Figure 1: System Frequency during the Initial Minutes of the February Load-Shedding Events[2]



3. Do Generators in ERCOT Have an Obligation to Perform?

No, generators in ERCOT do not have an obligation to perform. The ERCOT market is based on a Hayekian philosophy — that price provides all of the information necessary to ensure efficient availability, dispatch, maintenance, and investment in generation and generator performance.[3] This is an incentive-based system in which the prospect of profits for the sake of power results in optimal system generation investments. Accordingly, generators are only paid for the energy services they provide, incented by price signals, without an obligation to perform. This approach differs from some other organized electric markets,[4] which maintain reliability in part by having financial penalties for failure to serve when needed.

A linchpin of this incentive to perform in ERCOT is setting prices that capture the value of reliability to customers during periods of shortage. "The key connection is with the value of lost load (VoLL) and the probability that the load will be curtailed. Whenever there is involuntary load shed and the system has just the minimum amount of contingency operating reserves, then any incremental reserves would correspondingly reduce the load curtailment. Hence, the price of operating reserves should be set at the value of lost load."[5] For this mechanism to work, there must be "enough room to allow some generators to exercise a little market power and bid high enough to reflect the scarcity rent."[6] This is a delicate dance, balancing the behavior of generators and customer protection.

The Public Utility Commission of Texas's (Texas PUC) administratively approved system-wide price cap for ERCOT (based on an estimate of the VoLL) has tripled

2 ERCOT Presentation – Review of February 2021 Extreme Cold Weather Event. Slide 12, (Axis titles added by NRRI staff, (February 24, 2021), http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf

3 "Fundamentally, in a system in which the knowledge of the relevant facts is dispersed among many people, prices can act to coordinate the separate actions of different people in the same way as subjective values help the individual to coordinate the parts of his plan." See Hayek, F., 'The Use of Knowledge in Society," *American Economic Review* (1945): 519-530.

4 Organized energy market operators administer the transmission system independently of, and foster competition for electricity generation among, wholesale market participants, https://www.ferc.gov/industries-data/market-assessments/electric-power-markets

5 Hogan, W., *Electricity Scarcity Pricing Through Operating Reserves: An ERCOT Window of Opportunity* (November 1, 2012): 6, https://scholar.harvard.edu/whogan/files/hogan_ordc_110112r.pdf

6 Hogan, W, Texas Nodal Modal Market Design: Observations and Comments. Presented at ERCOT Energized Conference, Austin, TX (May 2, 2008), https://www.hks.harvard.edu/publications/texas-nodal-market-design-observation-and-comments

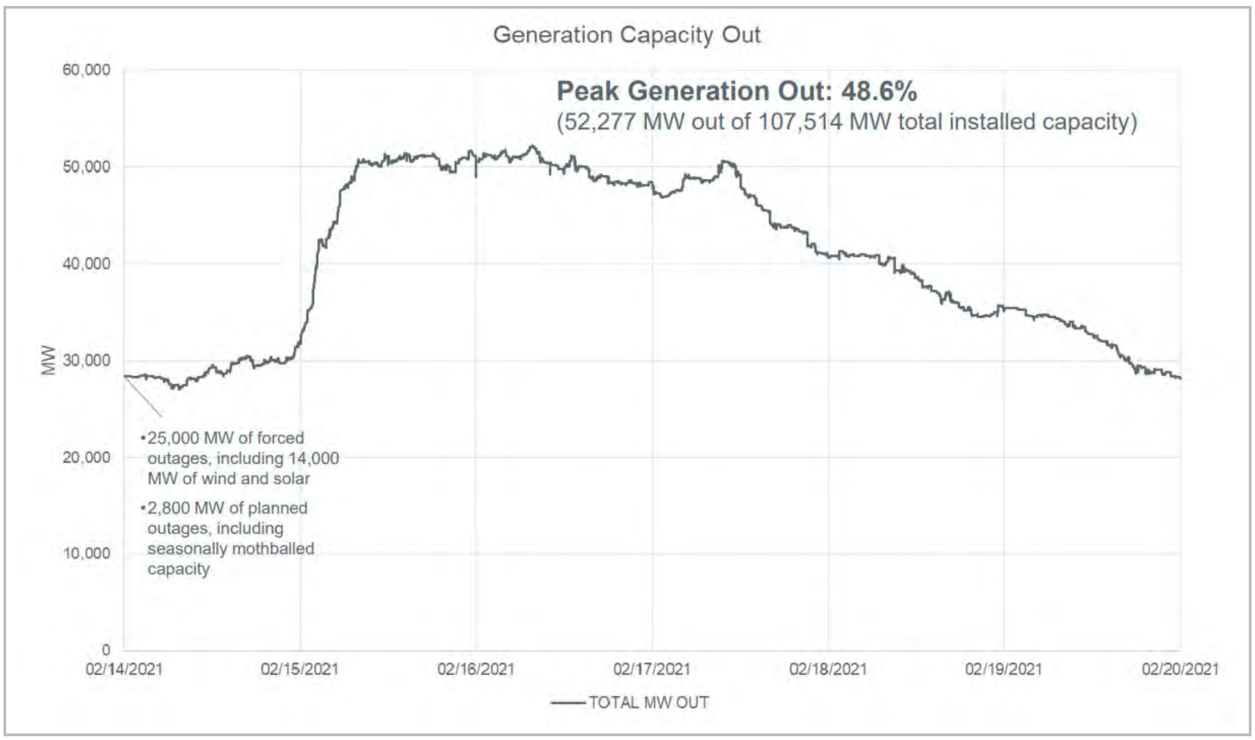
to $9,000/MWh between 2012 and 2015[7] and is incorporated into the automated market management software. This price cap is the highest in the nation. An empirical question is whether the increase in the market price cap has resulted in an improvement in generation performance, or investment in plant winterization.

4. How Did ERCOT and the Texas PUC Respond to System-wide Generator Performance Failure?

During the early stages of the event, generation of all types failed at an unprecedented rate, as demonstrated in **Figure 2**. Prior to shedding load, energy prices had reached or exceeded ERCOT's system-wide offer cap of $9,000/MWh, while prices are typically closer to $22/MWh.[8] As a result of the treatment of load curtailments by the ERCOT market algorithms, prices became very volatile, falling from scarcity pricing to as low as $1,200/MWh. As a result, natural gas-fired plants that were still online (26 GW failed during the event) were at risk of selling electricity at a loss, assuming that they could secure fuel. The result was an incentive that the market was not designed to properly address, highlighting the need to reevaluate scarcity pricing and the important interplay between the natural gas delivery interruptions and impacts to energy prices.[9]

ERCOT alerted the Texas PUC to this apparent anomaly, as the price of natural gas was increasing by

Figure 2: ERCOT Generator Failure during the Freeze[9]



7 The Texas PUC approved raising the energy price cap (high system wide offer cap) from $3,000/MWh to $4,500/MWh in August 2012 and subsequently approved gradually increasing the cap to $5,000 MWh in 2013, $7,000 MWh in 2014, and $9,000 MWh in 2015, http://www.beg.utexas.edu/files/cee/legacy/Gulen%26Soni_Impacts_of_Raising_Price_Caps_ERCOT.pdf. The Texas PUC determined the value of lost load as $9,000; see London Economics International LLC, "Estimating the Value of Lost Load Briefing"(June 17, 2013), http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf This offer cap was subsequently reviewed within a 2014 Brattle report, "Estimating the Economically Optimal Reserve Margin in ERCOT." http://www.ercot.com/content/wcm/lists/114801/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf

8 Gold, R., "Texas Power Market Is Short $2.1 Billion in Payments After Freeze," *Wall Street Journal*, February 26, 2021. https://www.wsj.com/articles/texas-power-market-is-short-2-1-billion-in-payments-after-freeze-11614386958

9 ERCOT Presentation – Review of February 2021 Extreme Cold Weather Event. Slide 13 (February 24, 2021), http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf

as much as 10,000 percent.[10] In response to the events of February 15, the Commission held an emergency six-minute meeting and issued an order granting ERCOT the authority to modify market outcomes that were "inconsistent with the fundamental [market] design."[11] The commission justified its decision by stating that "the market price for the energy needed to serve that load should also be at its highest."[12] This action could be seen as an effort to increase market confidence. However, the Commission's order resulted in higher energy prices during a time when customer demand was especially inelastic. The intention of ERCOT and the Texas PUC to incent generators to operate during the crisis was laudable. However, the extent to which these efforts were successful can be evaluated empirically by examining whether the availability of generating units on the system increased. If generators did not respond to the higher prices, then the increased revenues associated with these higher prices are a wealth transfer. The question is whether or not the scarcity pricing regime designed to support resource adequacy is an effective market mechanism for incenting performance during the cold snap. Other market design questions include whether additional market mechanisms, more than prevailing and prospective energy prices, are required to ensure that generators are available to maintain resilience, and what those mechanisms might be. A prudent regulatory decision would have required the Commission to weigh all these factors during that meeting.

ERCOT's request and the Commission's response are highly unusual and raise issues about whether market design processes were prepared for the potential outcomes resulting from prolonged system stress.

Although this freeze was especially extreme, it was not unprecedented — with a more severe storm of longer duration occurring in 1989,[13] and another severe and costly freeze in 2011. Other markets typically do not require real-time market changes to be authorized by regulators during a crisis, relying instead on market protocols that allow the system operator to take "out-of-market" actions to prioritize the stability of the system over potential price signals.[14]

The Commission's emergency order that enabled generators to bid $9,000/MWh on its own motion, demonstrates that maintaining scarcity prices was its highest priority. It is important to know why the market software produced the prices that it did after entering into EEA-3. Did the software perform as specified? And was the intent of ERCOT's market design to allow market prices to remain at the $9,000/MWh for as long as supply shortages persist, without regard for generator performance or the magnitude of profits earned? If so, where, when, and how was that considered? It is clear that this foreseeable event was not contemplated in the market design, raising the issue of whether the Commission's order was supported by adequate evidence for these circumstances. It is in the customer's interest for the Commission to reevaluate its order based on complete information about whether the market design actually supported its decision and to determine if the price increases allowed by the order should be readjusted. **Figure 3** demonstrates how the Commission's emergency order to address the dramatic price reduction after the load-shed events resulted in energy prices remaining near (and in some cases above[15]) the system-wide offer cap during most of the event.[16]

10 Paradis, C., "Texas Natural Gas Prices Attract Federal Investigation After 10,000% Spike," *International Business Times,* February 23, 2021, https://www.ibtimes.com/texas-natural-gas-prices-attract-federal-investigation-after-10000-spike-3150792

11 Gold, R., and Blunt, K., "Amid Blackouts, Texas Scrapped Its Power Market and Raised Prices. It Didn't Work." *The Wall Street Journal*, February 25, 2021, https://www.wsj.com/articles/texas-power-regulators-decision-to-raise-prices-in-freeze-generates-criticism-11614268158, Texas PUC Project No. 51617, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

12 Texas PUC Project No. 51617, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

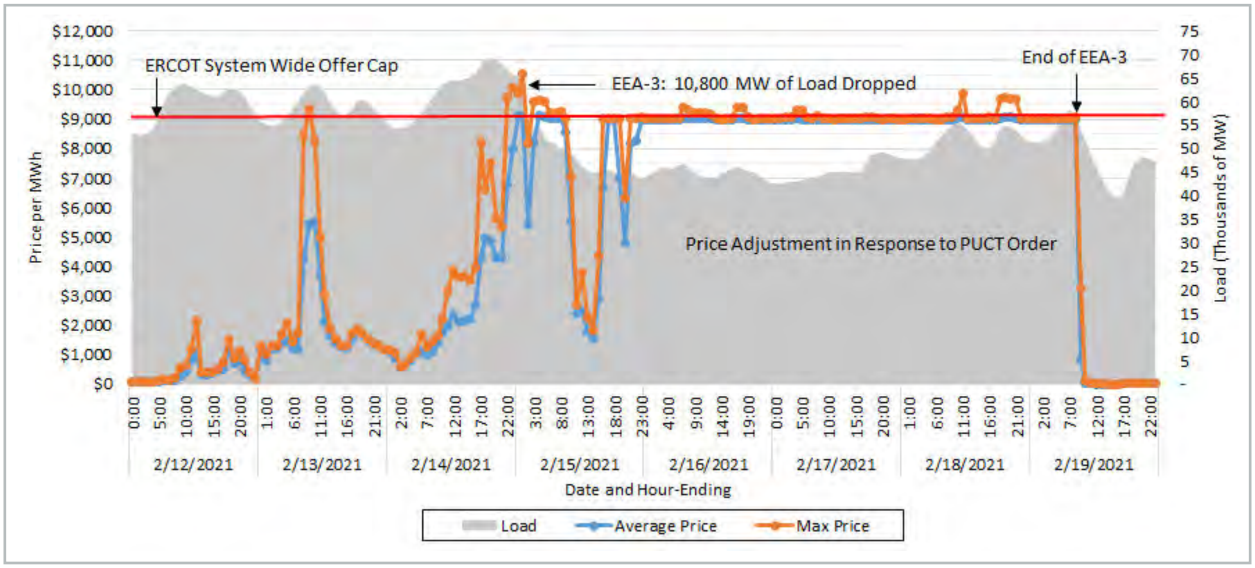
13 NERC whitepaper, *ERCOT Emergency Operations*, December 21-23, 1989, http://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/ERCOT%20Emergency%20Operation%201989.pdf

14 For example, the CAISO can perform out-of-market dispatch. These actions are recorded in the market as manual dispatches. See Market Disruption – EIM (January 6, 2021): 12, https://www.caiso.com/Documents/2720.pdf

15 While offers are limited by the energy price cap of $9,000/MWh, the market software can drive prices higher due to congestion and other system constraints. "Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints," http://www.ercot.com/services/comm/mkt_notices/archives/4645

16 Texas PUC Project No. 51617, Second Order Directing ERCOT to Take Action and Granting Exception to Commission Rules, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

Figure 3: Electricity Prices (8 ERCOT Load Zones) and Load during the Cold Weather Event[17]



5. Why is it Important to Investigate Whether Market Power was Exercised during the Freeze?

The Texas wholesale electric market, unlike markets regulated by the Federal Energy Regulatory Commission (FERC), does not require prices to be just and reasonable, thereby limiting the regulatory tools for adjusting prices. Prices in ERCOT are presumed to produce optimal results. The focus of the market design has been to provide generators with adequate revenues, resulting in reduced attention to ratepayer protections. The protection afforded to ratepayers for wholesale market transactions in Texas lies within the Commission's authority to address market power.[18] These remedies include both penalties and the ability to force disgorgement of excess revenues.

The potential exercise of market power goes beyond generator bidding behavior to market fundamentals. There are at least two ways in which the Texas market prices can be manipulated to earn extraordinary profits: passive withholding and gas price manipulation. The FERC has already announced its intent to examine "wholesale natural gas and electricity market activity during last week's extreme cold weather to determine if any market participants engaged in market manipulation or other violations."[19]

a. Did passive withholding exacerbate the crisis?

Withholding production is a recognized form of market power abuse in the electric industry. *Passive withholding* is defined here as the practice of selectively configuring part of a generation portfolio explicitly to exploit market design or system vulnerabilities.

Active withholding occurrs when a company that owns two or more generators in a particular market withholds the supply of one of those generators to increase the overall market price to compensate for the lost revenues of the withheld unit at normal prices. One way to withhold generation is to take a generator offline during needle peaks to perform discretionary inspections, such as deciding to shut down a generator during a time of a critical system conditions to have divers search a unit's cooling

17 Chart developed by NRRI staff using ERCOT's Historical RTM and Settlement Point Prices (SPPs) data for each ERCOT Load Zone). Maximum and average prices are for all intervals and all load zones for each hour, starting at 00:00, February 10, 2021, through 24:00, February 19, 2021. Load zones include: AEN; CPS; HOUSTON; LCRA; NORTH; RAYBN; SOUTH; WEST. http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13061&reportTitle=Historical%20RTM%20Load%20Zone%20and%20Hub%20Prices&showHTMLView=&mimicKey). (Load zone map available here: http://www.ercot.com/news/mediakit/maps

18 According to Chapter 39, Section 39.157 of the Texas Utilities Code: "On a finding that market power abuses or other violations of this section are occurring, the commission shall require reasonable mitigation of the market power…," http://statutes.capitol.texas.gov/StatutesByDate.aspx?code=UT&level=SE&value=39.157&date=3/18/2015

19 FERC News Release: FERC to Examine Potential Wrongdoing in Markets During Recent Cold Snap (February 22, 2021), http://www.ferc.gov/news-events/news/ferc-examine-potential-wrongdoing-markets-during-recent-cold-snap

water intakes for zebra mussels. This is a reasonable thing to do under normal circumstances, but is an exercise of market power when the system is experiencing such a high level of stress.

Passive withholding recognizes that during system emergencies, energy prices will be higher, potentially approaching the offer cap.[20] As a consequence, generator owners may have an incentive to make weatherization enhancements to only a portion of their fleet, enabling those units to operate through extreme temperatures and access higher revenues that would more than compensate for generation units that are forced out of service. Sophisticated generation and trading companies have game theorists who evaluate alternative ways in which their firms can gain profits. In retrospect, a firm that selectively winterized its generators would have made significant profits. The question is whether generators employed a practice of strategically preparing only a portion of its generating fleet for extreme cold weather events, because it would elevate prices and produce added profits.

In the event that a hypothetical entity owning multiple power plants had strategically winterized only a portion of their generation portfolio, thereby contributing to a system-wide shortage, there would be a potential for significant profits to the generators that remained online. Whether or not passive withholding has occurred can be determined by examining the underlying analysis of winterization investments by plant owners, fuel procurement practices, and effected availability for providers with larger generator portfolios.

It will be especially important for regulators to understand the specific actions generator owners and other entities previously undertook to invest in plant winterization or not, especially following the February 2011 cold weather events that resulted in a controlled load shed of 4,000 MW, affecting some 3.2 million customers. According to the joint North American Electric Reliability Corporation (NERC) and FERC report issued after that event, "Generators and natural gas producers suffered severe losses of capacity despite having received accurate forecasts of the storm. Entities in both categories report having winterization procedures in place. However, the poor performance of many of these generating units and wells suggests that these procedures were either inadequate or were not adequately followed."[21] Plant winterization is not mandatory in Texas.[22] In response to the state's energy crisis, the Texas Legislature and NERC are exploring potential mandatory weatherization standards.[23] Although there is an increasing recognition of the need to regulate winterization practices (including ensuring natural gas supply), the state also needs to investigate the underlying investment behavior of ERCOT's generators to determine whether passive withholding occurred.

b. Did natural gas price manipulation drive the peaker net margin?

The February 15 Texas PUC order demonstrates a clear nexus between natural gas prices and allowable prices in the ERCOT market. High natural gas prices provided the Commission with the regulatory rationale for suspending the low system-wide offer cap (LCAP). The impact of this suspension is demonstrated by **Figure 4**, which tracks ERCOT's estimates of the peaker net margin (PNM). ERCOT established the PNM metric[24] to track the net revenue that a hypothetical natural gas generator would earn in a single year, given the relationship between real-time

20 "Maintaining a price cap equal to the value of lost load (VoLL) during outages and prices reflective of marginal system costs in other types of scarcity events will provide efficient signals necessary for market-based responses from generators and demand response." – "Estimating the Economically Optimal Reserve Margin in ERCOT," prepared by Brattle for the Texas PUC, p. xi, http://www.ercot.com/content/wcm/lists/114801/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf

21 FERC/NERC Staff, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011*, (August 2011): 10, https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf

22 Travis, A., "Winter preparedness not mandatory at Texas power plants and generators, despite 2011 report" (February 17, 2021), https://www.kxan.com/investigations/winter-preparedness-not-mandatory-at-texas-power-plants-and-generators-despite-2011-report/

23 NERC Standard Project 2019-06 Cold Weather, https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx, Reuters, "Texas Governor Asks Legislature to Mandate Winterization of Generator," https://www.usnews.com/news/top-news/articles/2021-02-18/texas-governor-asks-legislature-to-mandate-winterization-of-generators

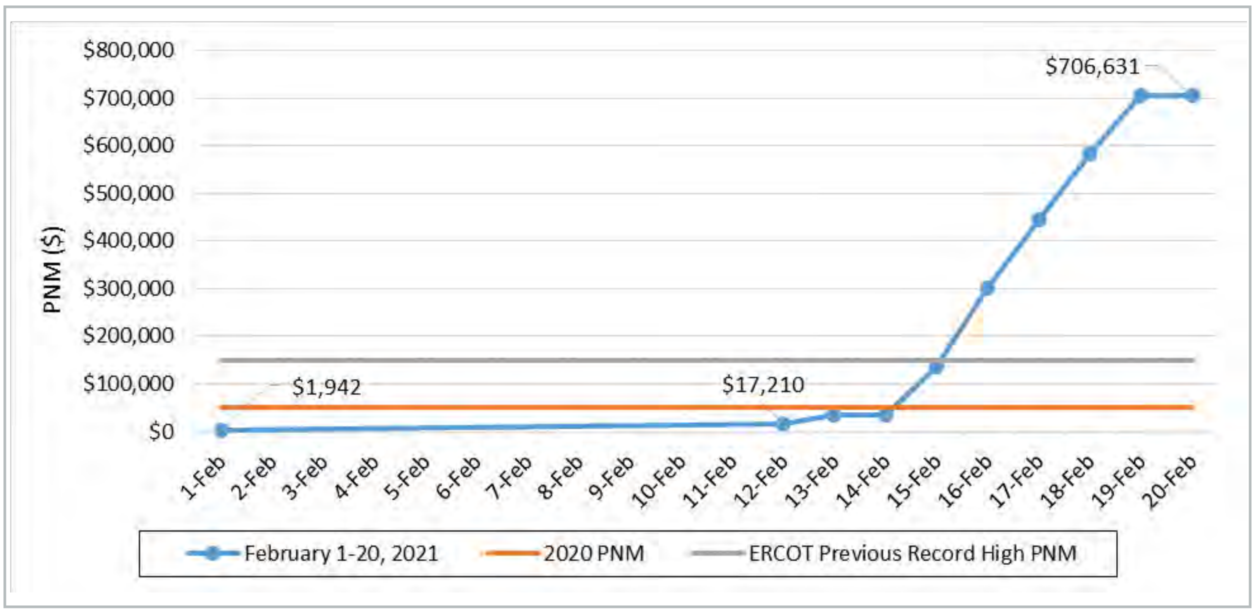
24 See Texas Commission rule 16 TAC § 25.505(g)(6), http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf

power prices and natural gas spot market prices. As a consequence, it is important to understand the price formulation that led to a 10,000 percent increase in natural gas prices to determine whether or not market power was exercised.

During the February events, ERCOT informed the Commission that generator revenues were approaching the PNM threshold ($315,000/MW-year)[25] or three times the annual cost of a new gas-fired generator. According to the rule, once the PNM threshold is achieved, the system-wide offer cap is set at the LCAP, which is "the greater of either (i) $2,000 per MWh and $2,000 per MW per hour; or (ii) 50 times the natural gas price index value determined by ERCOT (expressed in dollars per MWh and dollars per MW per hour)."[26] The price of natural gas during the event increased significantly, with the Houston Ship Channel spot prices approaching $400/MMBtu. This was a tremendous increase compared to the period both before the freeze and in prior years, when gas prices ranged between $2-3/MMBtu.[27] In response to this price increase, the Commission removed the LCAP of $2,000/MWh "to ensure appropriate energy prices to both consumers and generators"[28] and instead continued to enforce the high system-wide offer cap (HCAP) of $9,000/MWh. As shown in **Figure 4**, the PNM levels during the February event dwarfed prior records, demonstrating a generator's ability to garner extraordinary profits.[29]

The Commission's suspension of the LCAP resulted in some plant owners being exposed to extraordinarily high natural gas prices throughout the supply shortages, as frozen wellheads, pumps, and pipes reduced supply. ERCOT is the only market in the

Figure 4: Peaker Net Margin (PNM) February 1-20, 2021



25 Watson, M. "Texas regulators keep prices near $9,000/MWh cap during rotating outages," *S&P Global*, February 16, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/021621-texas-regulators-keep-prices-near-9000mwh-cap-during-rotating-outages

26 See Texas Commission rule 16 TAC § 25.505(g)(6), http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf

27 Matthews, C., Eaton, C., "U.S. Natural Gas Shortage Hampers Blackout Recovery," https://www.wsj.com/articles/u-s-natural-gas-shortage-hampers-blackout-recovery-11613671759

28 Texas PUC Project No. 51617, Second Order Directing ERCOT to Take Action and Granting Exception to Commission Rules, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

29 Watson, M., "Texas regulators keep prices near $9,000/MWh cap during rotating outages," *S&P Global*, February 16, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/021621-texas-regulators-keep-prices-near-9000mwh-cap-during-rotating-outages

United States whose market rules (the LCAP) tie energy prices directly to a natural gas price index.[30] Without the HCAP, gas prices would have driven energy prices to as high as $17,957/MWh.[31] Whether or not these natural gas prices may have been inflated due to an exercise of market power also warrants investigation by FERC and the appropriate Texas authorities. Whether sustained scarcity pricing was effective in bringing generators back online will be another important question to resolve in the aftermath of these events; for this reason, the Commission may decide either on its own or by direction from the legislature to also examine other market-design enhancements.

6. Was Enabling a Price of $9,000/MWh an Exercise of Structural Market Power?

It is necessary to evaluate whether there were forms of market power that have been experienced here that have not generally been contemplated in the literature. At issue is whether the market structure institutionalized the exercise of market power. The Texas PUC had an especially Hayekian marketcentric response to the emergency. As prices dropped with the curtailment of load, the Commission determined that "(e)nergy prices should reflect scarcity of the supply."[32] There is a more critical question as to whether the Commission order, which indicated prices should reflect scarcity conditions, led to unanticipated price regime both in terms of length and magnitude. The duration during which the price remained at the system-wide cap is unprecedented, with ERCOT reaching these high prices only on one other occasion due to scarcity.[33]

There is a real question of whether the implementation of the revised market rules that enabled market prices to remain at the offer cap for days is a form of market power invoked by the Commission and implemented by ERCOT. There is a presumption by the Commission that enabling such market prices was consistent with the design of the market. However, if this was not contemplated in the market design, then the Commission's actions were taken simply to raise market prices. Without sufficient information to create expectations about the response, this action needs to be investigated to determine whether or not it inappropriately led to the exercise of market power for which profits should be disgorged.

After the Commission issued its order, the PNM increased to over $700,000/MW-year in a matter of days. Given that 356 generating units[34] were impacted during the event as a result of frozen equipment, lack of fuel supply, and several other factors, it is an empirical question as to whether high energy prices resulted in a significant supply response. At issue is whether or not the Commission had a reasonable expectation that generators would actually respond. Indeed, it is important to determine whether this action inappropriately effectuated the enormous wealth transfer that will result in continued economic disruption, customer hardship, bankruptcy, and business failure in the midst of a pandemic.

The *Wall Street Journal* has reported the architect of the ERCOT[35] system has said that "this week's blackouts weren't indicative of a major design flaw, but rather inevitable imperfections stemming from extraordinary weather challenges."[36] This is where the Hayekian view of markets failed the people of

30 See Texas Commission rule 16 TAC § 25.505(g)(6), http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf

31 Watson, M. "Texas regulators keep prices near $9,000/MWh cap during rotating outages," *S&P Global*, February 16, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/021621-texas-regulators-keep-prices-near-9000mwh-cap-during-rotating-outages

32 Texas PUC Project No. 51617, https://www.puc.texas.gov/51617WinterERCOTOrder.pdf

33 A second instance occurred in January 2018; due to a software error and prices were corrected. Texas Coalition for Affordable Power, ERCOT Experiences Record Consumption, Real-Time Prices Reach $9,000 Cap. August 14, 2019, https://tcaptx.com/industry-news/ercot-real-time-prices-hit-record-9000-mark

34 ERCOT Presentation – Review of February 2021 Extreme Cold Weather Event. Slide 19, February 24, 2021, http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf

35 See: Hogan, W, "On an "Energy Only" Market Design for Resource Adequacy," - Hogan_Energy_Only_092305.doc (harvard.edu)

36 Blunt, K., Gold, R. – quoting William Hogan "The Texas Freeze: Why the Power Grid Failed," *Wall Street Journal*, February 19, 2021, https://www.wsj.com/articles/texas-freeze-power-grid-failure-electricity-market-incentives-11613777856

Texas. The wealth transfer associated with the market design is not an inevitable imperfection; it is the consequence of a market that was not designed to adequately respond to extreme weather events, which likely will be more common and potentially more widespread. If the Commission determines it was in error and that error resulted in institutionalizing the exercise of market power, it has the responsibility to evaluate the appropriate pricing during the freeze and to correct market prices based upon its powers to mitigate market power.

7. Did ERCOT's Independent Market Monitor Overlook the Potential Impact of Extreme Cold Weather Events?

ERCOT's independent market monitor, Potomac Economics, Inc., has published dozens of monthly, quarterly, and annual reports that examine the energy market structure and various market design attributes. None of these reports has examined the market impacts that might result from significant loss of generation due to extreme winter weather events. The impact of freezes on generation was a known risk that not only resulted in significant economic and customer harm during the freeze of 2011, but also caused over a thousand MW of capacity to trip due to freezing weather events in 2014, 2016, 2017, and 2018.[37] This raises the question of whether market oversight was sufficient to protect customers and other market participants. To answer this question, it is important to understand why the independent market monitor did not evaluate the potential impact of extreme cold weather events on generator profitability and the customer impact.

8. What Other Regulatory, Market Design, and Policy Issues Will Help Prevent a Future Reoccurrence?

a. Is a capacity market needed?

Analysis of different market structures that can support investment in both decarbonization and resilience is warranted. As described in the recent NRRI paper, *Wither the FERC: Overcoming the Existential Threat to Its 'Magic Pricing Formula' through Prudent Regulation,*[38] ERCOT's Operating Reserve Demand Curve (ORDC) is a capacity market. What distinguishes ERCOT's capacity market from those of the ISO-NE, NYISO, and PJM is that they are based on an installed reserve margin construct, whereas ERCOT's capacity market is based on an operating reserve construct. Both can be considered forms of capacity markets. They seek to achieve the same result, an efficient and effective power market, but use very different mechanism to achieve that outcome. As described in the NRRI paper, traditional approaches to capacity market design are under stress, given the increase in customer demand response and zero-marginal cost renewable generation. As a consequence, adopting a capacity market based on an installed reserve construct in Texas at this point would be to substitute one set of market design issues for another. What is clear is that ERCOT needs to examine new market mechanisms, specifically those structures that focus not only on remunerating generator performance, but also on protecting customers.

b. How did a sizable load forecasting error contribute to the event?

ERCOT's under-forecast of load contributed to its challenges by having to address higher than expected demand with generation and infrastructure that were unprepared to handle the extreme cold weather. The ERCOT normal load forecast for the winter peak was 57,699 MW, whereas the actual peak was nearly 70,000 MW.[39] This record exceeded ERCOT's extreme winter forecast of 67,208 MW, as well as the prior winter peak record of 65,915 MW set in January of 2018. Seasonal weather outlook, population growth, and economic projections are the primary drivers of most load forecasts. However, extreme weather events are becoming more frequent and have greater impacts, causing higher demand and reduced generator availability, which calls for improved modeling. Without a forward capacity

37 Allgower, A., Presentation at ERCOT Generator Winter Weatherization Workshop, September 5, 2019, http://www.ercot.com/calendar/2019/9/5/186081

38 Pechman, C., *Whither the FERC? Overcoming the Existential Threat to Its Magic Pricing Formula through Prudent Regulation* (Washington: National Regulatory Research Institute: 2021), https://www.naruc.org/nrri/nrri-library/research-papers/whither/

39 ERCOT, "Seasonal assessments show sufficient generation for winter and spring," Press Release, November 5, 2020, http://www.ercot.com/news/releases/show/216844

market, load forecasting becomes an even more important driver for investment in new capacity. Potential investors depend heavily on these public projections to understand ERCOT's expectation of resource needs and make decisions about building generation. If the winter load forecast had been more accurate, it is likely that it could have driven additional investment in more capacity. An important issue for regulators is whether ERCOT's load forecasting methods are adequate.[40]

c. Is it time for Texas to begin a comprehensive energy planning process?

The recent Texas energy crisis has highlighted the relationship of two critically important energy systems, electricity and gas, to the health and welfare of the people of Texas. Planning is not explicitly performed in Texas, because the state has taken the Hayekian approach—relying on the market to send sufficient price signals for the system to optimally plan. The approach of relying on the market has clearly failed the people of Texas not factoring in the importance of resilience, which is not just a cold weather issue but is important with respect to other extreme weather events, including hurricanes and heat. A comprehensive plan would provide feedback to electricity market design. Among other things, it would evaluate, the vulnerabilities of the system, the role of decarbonization, and the relationship between natural gas, and electricity. It would also evaluate the interplay of the energy system with other life and economy sustaining systems, such as water and health.

d. Is Texas unique in needing to re-evaluate the structure of its market?

There are a number of drivers that will have an impact on the structure of all markets. These include the need to incorporate resilience into market design, the impact of renewables on the market supply curve, and the additional investments needed to decarbonize, presumably while increasing electrification. The challenge in market design is to balance the needs of investors, who provide resources to serve load, with cost and the customer's desire for reliable and cost-effective cost power. There is a growing conversation, such as the one sponsored by the World Resources Institute and Resources for the Future, about the wide variety of ways to design markets.[41] The process of revising the ERCOT market would be enhanced by the participation of the Texas PUC staff and commissioners.

e. How is designing a market for reliability different than designing for resilience?

The nature (scale and scope) of the risk that you are designing the system to withstand is different for reliability than it is for resilience. ERCOT is a market for reliability in the traditional engineering/economics sense. It pays for reliability through scarcity pricing, and that price reflects a valuation of an outage of relative short term in a limited geographic footprint. The outage costs studies used to elicit VoLL evaluate outages for relatively short durations (usually of only a few hours) occurring frequently and without consideration of whether the outage is local or covers a wide-area. One design objective of the ERCOT market is to provide resource adequacy, based upon an expected load forecast and the probability of individual uncorrelated generator outages. The resilience risk is different. It is a systematic risk, also called a common-mode failure, in which large groups of generators are impacted at the same time, resulting in a simultaneous outages, as experienced during the Texas freeze.

f. Is increased integration with the Eastern Interconnection warranted?

Detailed power system planning studies are necessary to identify the benefits of increased reliability through a higher degree of interconnection of ERCOT to the U.S. grid. There likely wouldn't have been enough transfer capacity to make up for the 48.6 percent of ERCOT's generation that failed

40 EPRI outlines the shortcomings or current capacity planning protocols in meeting widespread and persistent outages.
EPRI. *Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy*, January 28, 2021 https://www.epri.com/research/products/000000003002019300
Maitra, A. and B. Neenan, *Measuring the Value of Electric System Resiliency: A Review of Outage Cost Surveys and Natural Disaster Impact Study Methods* (Palo Alto, CA: Electric Power Research Institute, 2017). https://www.epri.com/research/products/000000003002009670

41 World Resource Institute, "Market Design for the Clean Energy Transition: Advancing Long-Term Approaches." December 16, 2020, to December 17, 2020, https://www.wri.org/events/2020/12/market-design-clean-energy-transition-advancing-long-term

recently. During the February freeze, the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO), the two neighboring regional transmission organizations, also had operating issues, which necessitated power outages across portions of their systems to maintain system frequency. Importantly, however, increasing ERCOT interconnections would generally increase the available resource pool, which could provide significant reliability and resilience benefits.

9. How Will the Financial Consequences of This Event Be Resolved?

The physical crisis has subsided, thanks to the tireless efforts of many workers involved in system restoration. Most people have returned to their normal lives, but many will bear the long-term economic harm and emotional scars from the impact of this event for the foreseeable future. The staggering financial impacts on the utility sector will reverberate for months or years. Forty-two thousand customers had index rate plans that will bill them based on the market price, which remained at or near $9,000/MWh for several days. One Texas cooperative has already filed for bankruptcy after receiving a $1.8 billion bill for less than a week of power.[42] Some competitive retail suppliers that were not fully hedged and made fixed-price retail sales will have significant revenue shortfalls. So far, ERCOT has reported $2.1 billion in outstanding payments (approximately 17 percent of the amount owed for electric production during the freeze).[43] Additional bankruptcies will likely surface in the coming weeks. Ultimately, the consequences will be felt by customers, competitive retail providers, utilities and — possibly ERCOT itself. Bankruptcy is not a court of equity, and the resolution of these bankruptcies will create significant financial disruption. The Texas PUC will need to determine its role in this process, and how it can work to promote a just and reasonable outcome. To do so, it would be useful to account for the financial flows that occurred as a consequence of the crisis, including where the money came from and where it went, as well as identifying outstanding financial liabilities.

10. Conclusion

The Texas PUC and other relevant agencies, ERCOT, its stakeholders, the Texas legislature, and those harmed by this event need to understand details of how this catastrophic failure occurred. The lessons from this catastrophe must form the basis for future investments, policies, regulations, and market rules designed to ensure that this will never happen again. We hope that these questions and context provided by NRRI will help facilitate that process.

42 Reuters, "Texas power cooperative files for bankruptcy, citing $1.8 billion grid debt," March 1, 2021, https://www.reuters.com/article/us-bankruptcy-brazoselectric-texas-outag-idUSKCN2AT1FE

43 Gold, Russell, "Texas Power Market Is Short $2.1 Billion in Payments After Freeze," *Wall Street Journal*, February 26, 2021, http://www.wsj.com/articles/texas-power-market-is-short-2-1-billion-in-payments-after-freeze-11614386958

About the Authors

Dr. Carl Pechman
Dr. Carl Pechman, Director of the National Regulatory Research Institute, is an electricity economist with expertise in market design and the theory and practice of regulation. His experience includes work as a staff member at the New York Public Service Commission and the Federal Energy Regulatory Commission.

Elliott J. Nethercutt
Elliott Nethercutt is a Principal Researcher at the National Regulatory Research Institute (NRRI) where he specializes in state and federal electricity policy issues. Previously, he advanced market design enhancements at the California Independent System Operator (CAISO), developed reliability assessments at the North American Electric Reliability Corporation (NERC), and supported transmission siting efforts and smart grid funding programs at the U.S. Department of Energy (DOE).

About NRRI

The National Regulatory Research Institute (NRRI) was established in 1976 as the research arm of the National Association of Regulatory Utility Commissioners (NARUC). NRRI provides research, training, and technical support to State Public Utility Commissions. NRRI and NARUC are co-located in Washington, DC.

NRRI Insights provides a forum that gives readers information about and insights into new ideas, questions, and policy positions affecting the regulatory community. To that end, these articles represent differing points of view, policy considerations, program evaluations, etc. We hope that sharing diverse ideas will foster conversation that will support innovation in the industries we study. NRRI encourages readers to respond to these articles, either via "letters to the editor" or by joining the conversation with critiques/articles of their own. NRRI provides these diverse views as part of our role in fostering communication in the regulatory community. Please provide your comments and questions concerning *Insights* papers to slichtenberg@nrri.org.

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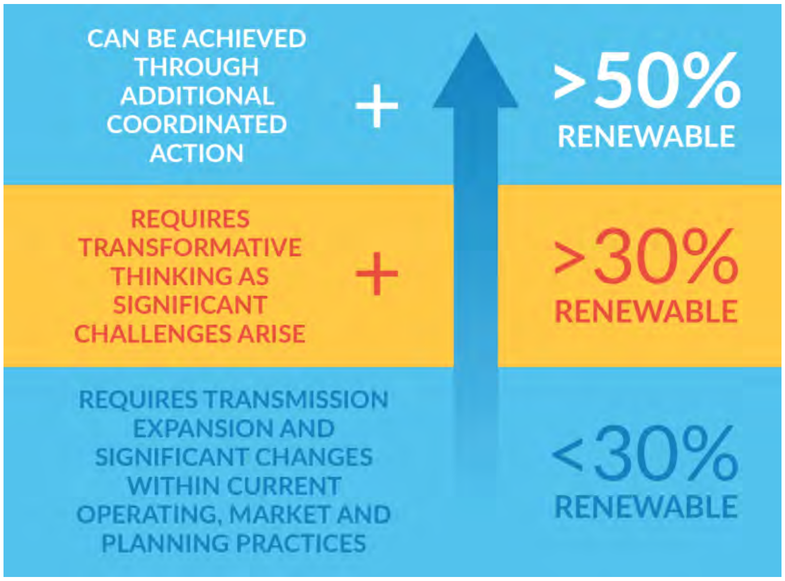
MISO's Renewable Integration Impact Assessment (RIIA)

EXECUTIVE SUMMARY – FEBRUARY 2021

misoenergy.org

Executive Summary

A Technically Rigorous Exploration



MISO's Renewable Integration Impact Assessment (RIIA) demonstrates that as renewable energy penetration increases, so does the variety and magnitude of the bulk electric system need and risks. Managing the system under such conditions, particularly beyond the 30% system-wide renewable level is not insurmountable and will require transformational change in planning, markets, and operations. Through coordinated action with MISO stakeholders, RIIA concludes that renewable penetration beyond 50% can be achieved.

While grid operators have managed uncertainty for decades, MISO is preparing for an unprecedented pace of change. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges. MISO calls this shared responsibility the Reliability Imperative, which is broken into four categories Market Redefinition, Long Range Transmission Planning (LRTP), Operations of the Future, and Market System Enhancements. RIIA is a key part of understanding the risks ahead.

RIIA is a technically rigorous systematic analysis that evaluates increasing amounts of wind and solar resources on the Eastern Interconnection bulk electric systems, with a focus on the MISO footprint. RIIA examines renewable penetration levels in 10% increments up to 50% to better understand the complexities of integration at each level. This assessment provides examples of integration issues and examines potential mitigation solutions.

RIIA is policy and pace agnostic: generation changes in the analysis are assumed to occur regardless of external drivers and timelines. As a technical impact assessment, RIIA does not directly recommend any changes to the existing electrical power system or construction of any new resources. That said, this body of work demonstrates that as renewable penetration increases, so does the variety and magnitude of system risk requiring transformational thinking and problem-solving.

"MISO, our members, and the entire industry are poised on the precipice of great change as we are being asked to rapidly integrate far more renewable resources. Given our regional Reliability Imperative, MISO must act quickly, deliberately, and collaboratively to ensure that the planning, markets, operations, and systems keep pace with these changes. We can achieve this great change if we work together."

— Clair Moeller, MISO President

New and Changing Risks Emerge, Requiring Support

As new risks emerge, adaptation within the existing planning, market, and operations constructs will suffice only to a point. As renewable generators are added, and conventional generators retire, RIIA identifies both new and changing risks and system needs:

New Stability Risk

The grid's ability to maintain stable operation is adversely impacted, primarily when renewable resources are clustered in one region of the transmission system. As inverter-based resources displace conventional generators, the grid loses the stability contributions of physically spinning conventional units. A combination of multiple technologies — such as high-voltage direct current (HVDC) lines, synchronous condensers, motor-generator sets and emerging technology such as grid-forming inverters — are needed to provide support, along with operational and market changes to identify and react to this risk as it occurs.

Shifting Periods of Grid Stress

The periods of highest stress on the transmission system shift from peak power demand to times when renewables supply most of the energy and long-distance power transfers increase. As power flows across longer distances, local planning and operational issues become regional challenges. As renewable resources supply most of the energy, the system becomes more dependent on the stability attributes of the remaining conventional generators, increasing the system risk associated with unexpected outages of those generators. As the direction and magnitude of power flows change rapidly due to the output of renewable resources that vary with weather conditions, increased flexibility, and innovation in planning and infrastructure is needed to adapt to new and shifting periods of stress.

Shifting Periods of Energy Shortage Risk

The risk of not having enough generation to meet demand shifts from the historic times of peak power demand to other periods, specifically hot summer evenings and cold winter mornings, when low availability of wind and solar resources is coincident with high power demand. These shifts are regional in nature. The colder and windier northern states exhibit different patterns than the hotter and sunnier southern states. To address this changing risk, the system needs to ensure (1) sufficient visibility of locational risk and (2) that other energy-supplying resources are available during these new times of need, with adequate transmission to deliver across regions.

Shifting Flexibility Risk

The ability of resources to provide system flexibility will be challenged. Current flexibility is needed primarily around the morning load ramp as energy demand increases and again during the evening load ramp as demand decreases. This risk shifts as variable renewables are added. As solar resources meet a larger share of the mid-day generation needs, non-solar resources are needed to ramp down in the morning and ramp up again in the evening to balance the solar pattern. Similarly, non-wind resources will ramp up and down to balance wind patterns, which change daily. To address this shifting risk, overall flexibility need increases and shifts to align with the periods in which it is required.

Insufficient Transmission Capacity

The current transmission infrastructure becomes unable to deliver energy to load. This is especially true if renewables are concentrated in one part of the footprint while serving load in another. Without added transmission, power flow across the footprint is hindered. The variable supply of renewables would, therefore, become much more challenging to manage, resulting in increased curtailment and markedly different operation of the remaining generators. Given how much time is typically needed to build transmission, proactive planning is necessary.

Integration Complexity Increases Sharply after 30% Renewable Penetration

In the general sense, system integration complexity is the effort needed to plan for, support, and operate new resources as they connect to the grid. In the RIIA analysis, complexity is measured quantitatively to understand its relative magnitude when comparing across various drivers.

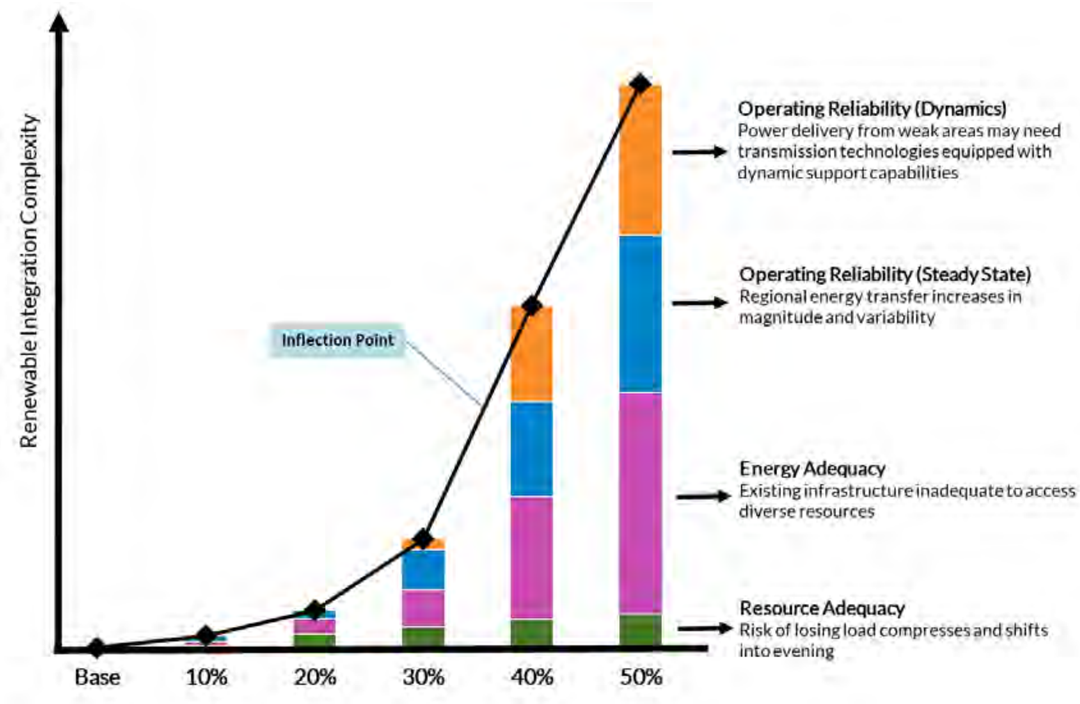


Figure 1: Increasing renewable penetration will significantly impact grid performance with complexity increasing sharply after 30% renewable penetration levels

> **"RIIA is the most comprehensive engineering study of the power system renewable transformation."**
> **— Aaron Bloom, Chair, System Planning Working Group, Energy System Integration Group**

RIIA found when the percentage of system-wide annual load served by renewable resources is less than 30%, the integration of wind and solar will require transmission expansion as well as significant changes to current operating, market, and planning practices — all of which appear manageable within MISO's existing framework. Beyond 30%, transformative thinking and coordinated action between MISO and its members are required to prepare for the significant challenges that arise (Figure 1). It is important to note that renewable growth does not happen uniformly across the MISO footprint, or the broader interconnected system. Growth occurs fastest in areas with high quality wind and solar resources, available transmission capacity, and favorable regulatory environments. For example, when MISO reaches 30% renewable energy penetration, some Local Resource Zones are likely to be approaching 100% renewable energy penetration. Locations which experience the fastest renewable growth experience challenges first, but beyond 30% renewable penetration the system as a whole facing new and shifting risks rather than simply local issues.

Today, MISO's renewable fleet accounts for 13% of MISO's system-wide energy, and MISO operates 26 GW of wind and 1 GW of solar. Nearly 80% of MISO's renewable resources are in the northwest region of MISO, concentrating the current integration challenges to one area.

Looking ahead, as the significant pipeline of generators with executed Interconnection Agreements reach commercial operation (6 GW of new wind, 10 GW of new solar), renewables are expected to account for approximately 20% of the system-wide annual energy mix. Beyond that, MISO Futures demonstrate the 30% milestone could occur as soon as 2026.

Three Key Focus Areas, RIIA Insights and Next Steps

RIIA illustrates areas of system weakness, recognizes when those weaknesses could become problematic and identifies potential means to address them. This work has informed initiatives already underway at MISO and will serve as a key input to initiatives in the future. The assessment aims to support a broader, more informed conversation about renewable integration impacts on the reliability of the electric system within the MISO stakeholder community and the greater industry. The analysis suggests three key focus areas for MISO and stakeholders (Figure 2) and informs the sequencing of actions required to manage various renewable penetration levels.

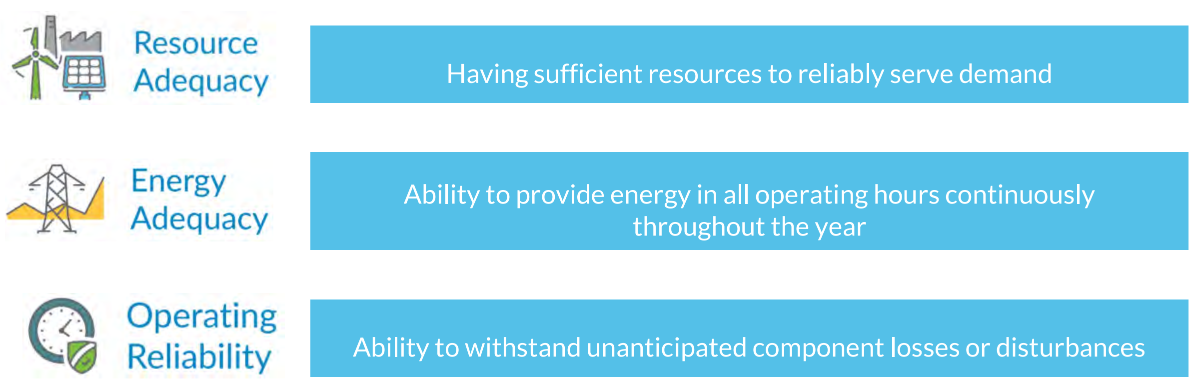
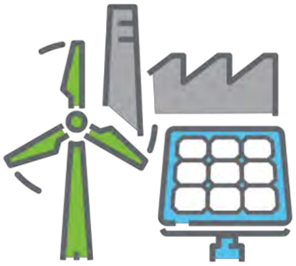


Figure 2: RIIA's three focus areas: Resource Adequacy, Energy Adequacy and Operating Reliability

Note: Where appropriate, the insights below are tied to the Reliability Imperative efforts in the categories of Market Redefinition, Long Range Transmission Planning (LRTP), Operations of the Future, and Market System Enhancements.

Resource Adequacy



Resource Adequacy is the ability of available power resources to reliably serve electricity demand when needed across a range of reasonably foreseeable conditions. Resource Adequacy complexity is defined as the effort needed to maintain capacity necessary to maintain a "one day in 10 years" loss of load expectation target.

RESOURCE ADEQUACY INSIGHTS

INSIGHT: Risk of losing load compresses into a small number of hours and shifts into the evening. The risk of not serving load shifts later into the evening and is observed for shorter durations with higher magnitude. Sensitivity analyses show risk shifting to winter and later in the evening, depending on technology and geographic mix.

NEXT STEP
- Ensure resource availability outside of traditional risk periods, both during evening hours and winter periods (Market Redefinition).

INSIGHT: Resource changes will significantly impact grid performance, with complexity increasing sharply after 30% renewable penetration levels.

NEXT STEP
- Develop and implement market solutions to identify issues prior to the system reaching 30% wind and solar penetration (Market Redefinition).

INSIGHT: Diversity of technologies and geography improves the ability of renewables to serve load. Yearly weather variations drive Resource Adequacy outcomes.

NEXT STEP
- Develop ways to increase the fidelity of renewable energy forecasts by using improved weather data.

RESEARCH STEP
- Explore ways to incentivize new resource additions to enhance technological and geographical diversity to serve MISO reliability.

Energy Adequacy

Energy Adequacy looks at the ability to operate the system continuously and deliver sufficient energy every hour of the year. Energy Adequacy complexity is defined as the effort to develop the transmission needed to maintain and deliver renewable energy during every hour of the year. The generation fleet's ability to respond to the load is limited by existing generation and transmission constraints, and new transmission costs act as a proxy to measure the additional flexibility needed to access diverse resources.

ENERGY ADEQUACY INSIGHTS

INSIGHT: With renewable penetration levels above 40 percent, there is both a greater magnitude and increased variation of ramping needed. Increasing variability due to renewable generation will require generators to perform differently than they are today.

RESEARCH STEPS

- Explore the landscape of system flexibility solutions (e.g., renewables as a solution to variability need and nuclear plant ramping).
- Explore changing risks such as the ability of the natural gas system to deliver fuel to enable gas generator flexibility, and fewer units providing needed system flexibility (due to retirements).
- Explore flexibility incentives (Market Redefinition).

INSIGHT: Existing infrastructure becomes inadequate to fully access the diverse resources across the MISO footprint. Grid technology needs to evolve as renewable penetration increases, leading to an increased need for integrated system planning.

NEXT STEP

- Educate stakeholders about complexities and opportunities of emerging technologies (LRTP).

RESEARCH STEPS

- Explore co-optimization between economic and reliability transmission needs, along with resource deployment (software, process, and data development needed).
- Explore additional opportunities to align and co-plan for system needs across the various MISO planning functions.
- Explore the gaps, opportunities, costs, and benefits of new grid technology (such as FACTS, VSC HVDC lines, grid-forming inverters) and its ability to solve emerging grid needs.

INSIGHT: Storage paired with renewables and transmission help optimize the delivery of energy.

RESEARCH STEPS

- Explore concept to understand benefits better
- Explore process changes to align benefits with outcomes

Operating Reliability

Operating Reliability studies the system's ability to withstand sudden disturbances to system stability or unanticipated loss of system components. This focus area is subdivided into "steady state" and "dynamic stability" analysis and considerations.

Steady State

Steady-state analysis examines whether the transmission system exceeds the thermal ratings of lines, transformers, and other devices following deviations from normal operating parameters occurring without warning. Complexity in steady-state analysis is defined as the effort to create the transmission needed to ensure acceptable system performance after outages.

OPERATING RELIABILITY — STEADY-STATE INSIGHTS

INSIGHT: Resource location and system conditions cause transmission risk shifting to spring and fall and increasing in frequency. Additionally, sensitivity analysis shows risk shifting to summer shoulder load periods during high solar output.

NEXT STEPS

- Align planning dispatch assumptions with shifting system conditions and risk (LRTP).
- Develop tools and processes to capture changing risks as they appear for transmission planning (LRTP).

RESEARCH STEP

- Evaluate opportunities to align and co-simulate power-flow and production cost models.

INSIGHT: Regional energy transfer increases in magnitude and becomes more variable, leading to a need for increased extra-high voltage transfer capabilities. Transmission bottlenecks shift to higher voltage lines due to increased regional energy transfers.

NEXT STEPS

- Proactively align to future needs, develop long-range, cost-effective, and least-regret transmission plans, and move construction forward (LRTP).

Dynamic Stability

Voltage stability, frequency stability, rotor angle stability, and non-oscillatory behavior of electrical quantities are considered dynamic stability issues. Dynamic stability includes maintaining operating equilibrium of three distinct elements after a disturbance in the electric grid: (a) voltage stability; (b) adequate frequency response; and (c) rotor angle stability. Complexity in the Operating Reliability — Dynamics analysis is defined as the effort to install transmission equipment and control system tuning required to ensure stable operation.

RIIA identifies potential issues with all three dynamic stability elements along with converter-driven stability, which is an additional category associated with inverter-based equipment. Concerning voltage and converter-driven stability, the assessment demonstrates that as inverter-based resources increase in penetration, there is a corresponding decrease in the online thermal generation, which intensifies reliability issues. This is significant because commercially available inverter-based resources, such as renewables, need strong voltage connections to operate reliably and efficiently. This study identifies several approaches to address the issues, such as tuning inverter controls, re-dispatching generation, adding synchronous condensers, and using advanced technologies (FACTS, VSC HVDC). Frequency-related risks can be resolved by adding storage or maintaining online headroom from resources, including wind and solar.

OPERATING RELIABILITY — DYNAMIC STABILITY INSIGHTS

INSIGHT: Power delivery from "weak-grid" areas may need transmission technologies equipped with dynamic support capabilities.

RESEARCH STEPS

- Explore and decide ways to address "weak-grid" issues (such as improved inverter technology, new technology pilots, operational visibility, proactive and integrated transmission planning).
- Update inverter control tuning approaches as penetration of inverter technologies increases.

INSIGHT: Small signal stability issues increase in severity after 30% renewable penetration, thereby requiring power system stabilizers. Frequency response is stable up to 60% instantaneous renewable penetration but may require additional planned headroom beyond 60%.

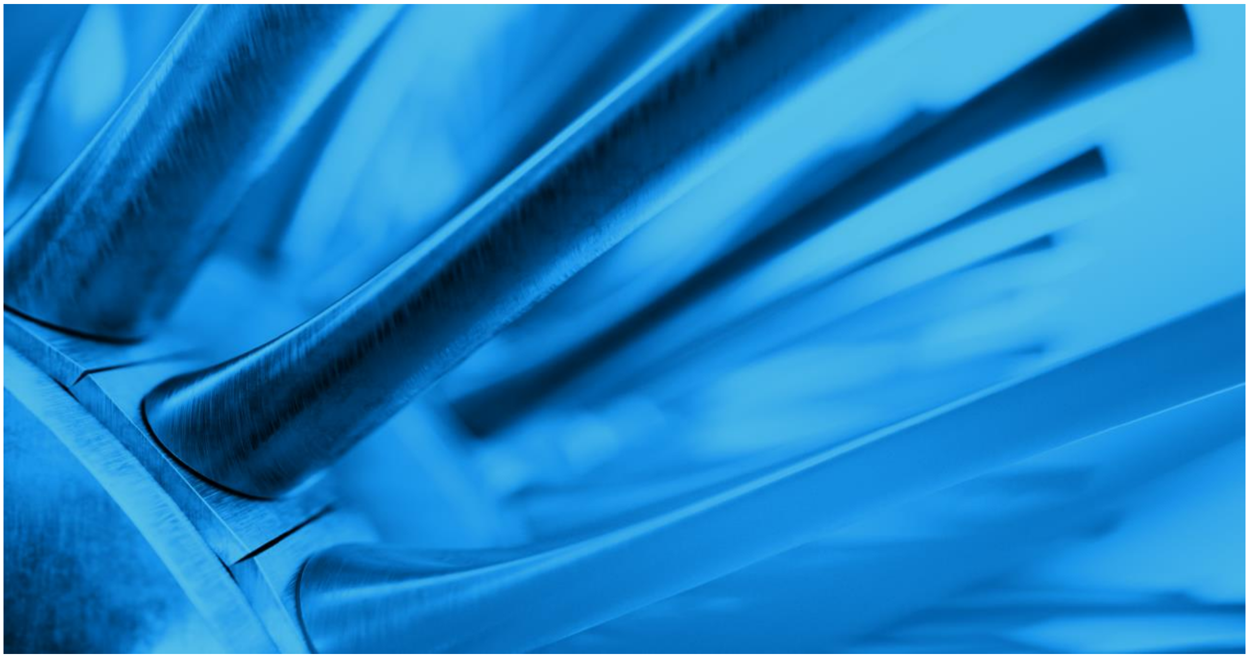
RESEARCH STEPS

- Explore new methods to stabilize the grid, such as battery storage.
- Explore operations tools to monitor and commit power system stabilizers when needed.

INSIGHT: On average Critical Clearing Time (CCT) improves as large generating units are replaced, but new local issues emerge.

RESEARCH STEP

- Explore process to plan for new protection techniques or new transmission devices.



Additional Work Is Needed

RIIA is the culmination of four years of stakeholder collaboration and intense exploration into the impacts of increasing renewable integration in the MISO region. While the analysis is highly comprehensive, it is not finished. Additional work is needed to transform the way MISO and the power system are planned and operated to continue to maximize reliability and value creation across the region in a high renewable system. RIIA has shown that while there are challenges, the MISO region can achieve renewable penetration of at least 50% with transformational change and coordinated action amongst all participants.

> **"We believe it will take transformational change, including redefined markets and planning processes, to enable efficient and reliable operations in the future. Coordinated action amongst all stakeholders will be necessary to facilitate participants' decarbonizations goals and plans for higher levels of renewable generation."**
>
> **— Richard Doying, MISO EVP Market & Grid Strategies**

ENERGY RESOURCES PLANNING TASK FORCE

TESTIMONY QUESTIONS

Please send your responses to ERPTaskForce@adeq.state.ar.us on or before April 30, 2021.

ATTORNEY GENERAL OFFICE

1. **To help the Task Force understand the various ongoing efforts currently under review by other agencies, could the Attorney General briefly summarize the type of issues your Office will be working on with respect to the power shortage events that occurred during the February winter weather event.**

    Response: Arkansas Attorney General Leslie Rutledge is conducting simultaneous investigations of the actions of public utilities and of potential violations of Arkansas's price-gouging laws relating to the February Winter Weather Event. Her investigations are not limited to power shortages. As or perhaps more importantly, the Attorney General is investigating energy pricing during the Event, the potential financial impact on Arkansans, and whether the financial impact can be mitigated.

    <u>Investigation of Public Utilities</u>

    On February 25, 2021, Attorney General Rutledge sent a letter to Arkansas Public Service Commission Chairman Ted Thomas asking that the Commission "open an investigation of the cost of energy – power and natural gas – incurred by Arkansas's electric and natural gas utilities during the recent severe weather event." A copy of the letter is attached. On March 4, 2021, the Commission opened the investigation sought by the Attorney General. See attached Order No. 1 in APSC Docket No. 21-036-U. The Attorney General is an active participant in that docket, and she has issued a number of discovery requests to regulated utilities.

    First, the Attorney General will be investigating the specific actions taken by Commission-jurisdictional natural gas and electric utilities during the February Winter Weather Event. The Attorney General is reviewing both action during the Event itself, but also the actions taken in the short and long-term leading up to the Event.

    Additionally, the Attorney General will be analyzing the February Winter Weather Event to determine what lessons can be learned and what actions to recommend to the Commission for future resource planning.

    The Attorney General anticipates that the aforementioned investigations and need for potential adjustments may take place across several Commission Dockets which are directing dealing with the February Winter Weather Event, or utility matters that may be impacted by same.

Price-Gouging Investigation

In addition, as indicated in her February 25 letter, Attorney General Rutledge "has opened an investigation of potential price gouging by parties that are not subject to the Commission's jurisdiction." To that end, the Attorney General's Office (AGO) will focus initially on price increases for natural gas. The AGO has met or is scheduled to meet with all natural gas utilities and electric utilities that use natural gas to generate electricity. This includes both public utilities regulated by the Commission and municipal utilities. Civil Investigative Demands (CIDs) have been issued to these utilities seeking information about their natural gas suppliers and pipeline service providers. See attached CID example. CIDs have also been issued to several large volume industrial and commercial natural gas users that purchase natural gas supplies from third parties, not from public or municipal utilities. The information that is being gathered will help the AGO determine which natural gas suppliers should be investigated for potential price-gouging.

Review of sales of electricity in power markets for potential price-gouging will begin in May. That sales of power occur in markets facilitated by Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP).

2. Are there any recommendations or areas of further investigation that the Attorney General would like to bring to the attention of the Task Force with regard to addressing energy supplies during future events?

Response: The Attorney General believes that her office and the Commission have adequate authority and enforcement tools to investigate and hold accountable any party that acted imprudently or in violation of Arkansas's public utility laws and consumer protection laws. The Attorney General also believes that recently enacted Act 641 will provide another source of funds that can be used by public utilities to arrange long-term financing of storm-related costs at low interest rates and to recover those costs from ratepayers in a reasonable time period.

In the AGO's meetings with municipal utilities, the need for similar funding mechanisms became apparent. While not every municipal utility may require financial assistance from the State when severe winter weather produces incredibly high costs, having access to grants, loans or other types of funding would be very beneficial for those utilities who do not have the financial means to meet their obligations to natural gas suppliers and also provide police and fire protection and other essential services.

The Attorney General would point out certain issues relevant to the February Winter Weather Event are likely within the exclusive jurisdiction of the federal government, and more specifically the Federal Energy Regulatory Commission (FERC). FERC has exclusive jurisdiction over interstate commerce involving the transmission grid, including rates and tariffs for the two Regional Transmission Organizations (RTOs) – MISO and SPP – that currently operate in Arkansas. FERC also regulates interstate gas pipeline transportation. Many municipal electric systems, and wholesale customers (both natural gas and electric), may need to address their cost issues directly with FERC.

There may also be issues pertaining to gas production, markets, and actions taken during the

February Winter Weather Event that are within the jurisdiction of the Federal Trade Commission (FTC) and/or the United States Department of Justice.

The Attorney General believes that cooperative regulation and enforcement jurisdiction exists into many of these issues, and will attempt to remain apprised of actions at FERC, FTC, and other courts of law, including the potential for direct action by the Attorney General of Arkansas into any such proceedings.

The Attorney General will also seek out cooperative opportunities with the Offices of Attorney General in other states affected by the February Winter Weather Event, to the extent that multi-state litigation might align to the benefit of Arkansas.

The Attorney General would like to make clear to the Task Force that resolution of all investigations and potential litigation involving issues relevant to the February Winter Weather Event may take months to fully conclude.

February 25, 2021

Hon. Ted Thomas, Chairman
Arkansas Public Service Commission
P.O. Box 400
Little Rock, Arkansas 72201

Re: Request for Investigation of the Cost of Energy Incurred by Arkansas Utilities During the Recent Severe Weather Event

Dear Chairman Thomas:

Recent winter storms exposed great disparities between consumer demand for energy and the ability of Arkansas's utilities to meet that demand in severe weather. Arkansans experienced service outages, and many businesses were forced to close. In the coming weeks, we will know more about the impact of energy shortages on customer bills. We anticipate that customer bills may skyrocket because of the high prices paid by utilities to third parties for energy needs that were either unanticipated or needed to replace resources that failed to materialize. Before these costs appear on customer bills, I respectfully request that the Arkansas Public Service Commission open an investigation of the cost of energy – power and natural gas – incurred by Arkansas's electric and natural gas utilities during the recent severe weather event.

Specifically, the Commission should investigate:

- The impact on rates and whether higher costs should be passed on to ratepayers;
- The cause of outages and significant operational problems experienced by Arkansas public utilities;
- Whether Arkansas public utilities were sufficiently prepared to respond to the severe weather;
- How the actual weather compared to the weather used to model peak day needs;

- The accuracy of peak day forecasting;
- The actions taken to meet peak day capacity and supply needs;
- What emergency plans were in place to secure natural gas and any other necessary fuel to meet unanticipated needs;
- Performance of suppliers under contract to affected Arkansas public utilities; and
- Actions taken by electric utilities in response to MISO and SPP alerts.

Apart from its proposal that the Commission investigate these matters, the Attorney General has opened an investigation of potential price gouging by parties that are not subject to the Commission's jurisdiction.

Sincerely,

Leslie Rutledge
Arkansas Attorney General

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN INVESTIGATION	)	
INTO THE OPERATIONS, PROCEDURES, AND	)	DOCKET NO. 21-036-U
PERFORMANCES OF THE REGULATED	)	ORDER NO. 1
UTILITIES DURING THE WINTER WEATHER	)	
EVENT IN FEBRUARY 2021	)	

ORDER

On February 11, 2021, through February 20, 2021, Arkansas experienced extreme weather events resulting in sub-zero temperatures and the accumulation of ice and record snowfalls across the state. Although many of the state's regulated utilities performed admirably during this unprecedented weather event, the loss of power, entreaties to customers to conserve natural gas and electricity, and rolling blackouts point to a need for the Arkansas Public Service Commission (Commission) to ensure that utilities are doing all they can to ensure its systems are resilient, services are safe and reliable, and customers do not experience preventable loss of power or are saddled with exorbitant utility costs.

Pursuant to Ark. Code Ann. §§ 23-2-308, 23-2-309, and 23-2-310, the Commission hereby opens an investigation into the utilities' preparation, response, operational performance and communication regarding the winter weather events in February 2021, impacts on customers, best practices, and lessons learned going forward.

Additionally, utilities may have experienced significantly increased expenses related to fuel and transportation, purchased power, and other commodity and operational costs because of these events. As most utilities will soon be required to file for adjustments to riders which recover those costs from ratepayers,[1] the unabated impact of these increased costs could cause rate shock for utility customers.

Any utility which has experienced a significant impact from these increased costs is urged to propose procedures for cost recovery which avoid rate shock to its customers as the utilities file for rider adjustments. Procedures should protect the right of the utility for an opportunity to recover costs while balancing the impact on the utility's customer.

All jurisdictional electric, gas, and water utilities are hereby made parties to this Docket, and the Secretary of the Commission is directed to serve a copy of this Order on the parties. A procedural schedule for conducting the investigation will be set by subsequent order.

[1] For example, Energy Cost Recovery Riders, Cooperative Cost of Energy Adjustments, Gas Supply Rates, and Cost of Pumping Adjustments.

BY ORDER OF THE COMMISSION.

This _4th_ day of March, 2021.

Ted J. Thomas, Chairman

Kimberly A. O'Guinn, Commissioner

Justin Tate, Commissioner

Mary Loos, Secretary of the Commission

I hereby certify that this order, issued by the Arkansas Public Service Commission, has been served on all parties of record on this date by the following method:

____U.S. mail with postage prepaid using the mailing address of each party as indicated in the official docket file, or

✓ Electronic mail using the email address of each party as indicated in the official docket file.

Kate Donoven
Senior Assistant Attorney General
Direct Dial: (501) 682-8114
Email: kate.donoven@arkansasag.gov

April x, 2021

Re: Civil Investigative Demand (CID), Price Gouging Investigation 2021-0083 – Natural Gas Prices

Dear Municipal Utility:

The Consumer Protection Division of the Office of Arkansas Attorney General Leslie Rutledge is investigating the prices paid by Arkansas's utilities for natural gas supplies and pipeline services used during extreme weather that occurred in February 2021. Because some municipalities purchase natural gas in providing utility service to Arkansans, we need information from your municipality so that we can determine the sources and causes of high natural gas prices and whether those prices were cost-based or market-driven.

Governor Asa Hutchinson's February 10, 2021 winter weather emergency declaration triggered the protections of Arkansas's price gouging law that remained in effect until March 12, 2021. See Executive Order 21-02 attached. Arkansas's price gouging law, Ark. Code Ann. § 4-88-301, *et seq.*, prohibits any person or business from charging more than ten percent (10%) above the pre-emergency price of goods or services. The scope of the law is broad and intended to cover anything that may be needed in the event of a state of emergency. As it relates to Executive Order 21-02, covered goods and services include, but are not limited to, natural gas used for space heating, electric generation and other consumer and business purposes. Ark. Code Ann. §§ 4-88-303, 4-88-102(4) and 4-88-102(7).

While the law sets a general 10% cap on price increases during an emergency, businesses may lawfully charge a higher price if they can establish that the higher price is directly attributable to additional costs for labor or materials used to provide the goods or service. In such a limited situation, the business may charge no more than 10% above the total of the cost to the business, plus the customary mark-up applied for that good or service in the normal course of business. Rates that are set by the Arkansas Public Service Commission or which are otherwise based on the costs incurred by the utility may fall within this "safe harbor."

Wholesale suppliers are not exempt from the price gouging law. If a supplier increases its prices for goods or services by more than 10% during a state of emergency, it may run afoul of the price gouging law if the increase is based on increased demand and shortages of natural gas during the state of emergency. To avoid liability under the price gouging law, the wholesale supplier must demonstrate that its price increases were based on increased costs and that its price complies with Ark. Code Ann. § 4-88-303.

If a business or individual violates the price gouging law, the Attorney General can seek injunctive relief, restitution to consumers, costs, attorneys' fees, and civil penalties up to $10,000 per violation. Criminal sanctions may also apply to violators.

When the Attorney General determines that an investigation should be made into whether a person has engaged in, is engaging in, or, shows evidence of intent to engage in price-gouging, she may: (1) require any person to file a statement or report in writing as to the facts and circumstances concerning the matter, together which such other data as may be reasonably related thereto; (2) examine any oath or take the deposition of any person; and (3) examine any records relating thereto. Ark. Code Ann. § 4-88-111(a). Similarly, the Attorney General may seek information from a consumer or any other person or business that may have information that is pertinent to its investigation.

To assist in our investigation of natural gas price increases, please provide the following information:

1) Please provide the following information relating to your municipality's purchases of natural gas supplies during the period from November 1, 2020, through March 12, 2021.

a. Identify your municipality's natural gas suppliers and pipeline service providers for February 10 - March 12, 2021 within five (5) business days. For each natural gas supplier or pipeline service provider listed in response to this question, please provide the name and mailing address of the supplier or provider and, if known, its agent for service of process.

b. Invoices for the purchase of natural gas supplies and pipeline services, including transportation, no notice and storage services within ten (10) business days.

c. If not provided on the invoice, the dates, quantities and prices for all natural gas supply and pipeline service purchases within a reasonable time period to be mutually agreed upon.

d. Purchase orders and/or contracts under which the natural gas supplies or pipeline services were purchased within ten a reasonable time period to be mutually agreed upon.

2) Please provide all correspondence between your municipality and the supplier related to the purchases of natural gas supplies and pipeline services identified in response to question #1 within a reasonable time period to be mutually agreed upon. Correspondence includes emails, letters, texts, instant messages, social media posts, faxes, and any other record of information exchanged.

3) All correspondence between your municipality and the supplier that is related to plans, preparation, actions, or strategies for meeting supply demand during weather disasters within a reasonable time period to be mutually agreed upon.

All information submitted in response to this inquiry is protected from disclosure under the confidentiality provisions of Ark. Code Ann. § 4-88-111. The Arkansas Deceptive Trade Practices Act (ADTPA) protects all information submitted in response to a CID from Freedom of Information Act (FOIA) requests and the Attorney General cannot be compelled to release any information without your consent and only if ordered by a court for good cause. Should the Attorney General use the information in court, materials that contain proprietary information and trade secrets can be presented in camera with approval of the court after notice to the person furnishing the material. Documents, statements, and information provided in response to a request by the Attorney General are subject to the following statutory safeguards:

> (b) Unless otherwise ordered by a court for good cause shown, no statement or documentary material produced pursuant to a demand under this section shall be produced for inspection or copying by, nor shall the contents thereof be disclosed to, any person other than the authorized employee of the Attorney General without the consent of the person who produced the material.
> (c) The Attorney General or any attorney designated by him or her may use the documentary material or copies thereof in the enforcement of this chapter by presentation before any court, provided that any such material which contains trade secrets shall not be presented except with the approval of the court in which the action is pending after adequate notice to the person furnishing such material. However, when material containing trade secrets is presented with court approval, the material and the evidence pertaining thereto shall be held in camera and shall not be part of the court record or trial transcript.
> (d) No statements, documents, or other information maintained or produced as a result of an ongoing investigation of possible violations of this chapter shall be disclosed to any person other than those persons specifically authorized by the Attorney General to receive such information.

We appreciate your cooperation with our office and are available to discuss if you have any questions or concerns. To facilitate our ability to comply with Ark. Code Ann. § 4-88-111(c), we request that any information provided in response to this CID that contains a proprietary fact or trade secret be clearly and distinctly designated as such. Bates stamps and bookmarked pdfs are appreciated but not necessary.

Sincerely,

Kate Donoven

Kate Donoven
Senior Assistant Attorney General

Encl: E0-21-02
Cc: Chuck Harder, Deputy Attorney General Public Protection,
Christina Baker, Assistant Attorney General, CURAD, and
Trent Minner, Assistant Attorney General

STATE OF ARKANSAS

EXECUTIVE DEPARTMENT

PROCLAMATION

EO 21-02

TO ALL TO WHOM THESE PRESENTS COME – GREETINGS

EXECUTIVE ORDER TO PROVIDE FUNDING, AS AUTHORIZED BY ARK. CODE ANN. §§ 12-75-114, AS AMENDED, FROM THE GOVERNOR'S DISASTER FUND, EMERGENCY RESPONSE FUND

WHEREAS: On or about February 9, 2021, a winter storm began and continues to cause freezing rain, sleet, snow, and ice with such severity to warrant executive action to alleviate hardship and suffering in the State of Arkansas; and

WHEREAS: Freezing rain, sleet, snow, and ice accumulation on roads and power lines due to the winter storm presents dangers that warrant executive action; and

WHEREAS: Great hardship has been wrought upon the citizens, businesses, and public and private property within the State of Arkansas; and

WHEREAS: Adverse circumstances have been brought to bear upon the citizens and public properties within the state; and

WHEREAS: These political subdivisions require supplemental assistance from the state to recover from these losses;

NOW, THEREFORE, I, ASA HUTCHINSON, Governor of the State of Arkansas, acting under the authority vested in me by Ark. Code Ann. §§ 12-75-101, *et seq.*, do hereby declare a state of emergency and direct the sum of $100,000.00 to be obligated from the Emergency Response Fund of the Governor's Disaster Fund to be used at the discretion of the Director, Arkansas Division of Emergency Management, to defray both program and administrative costs.

IN TESTIMONY WHEREOF, I have hereunto set my hand and caused the Great Seal of the State of Arkansas to be affixed this 10th day of February, in the year of our Lord 2021.

GREAT SEAL OF THE STATE OF ARKANSAS

Asa Hutchinson, Governor

Attest:

John Thurston

John Thurston, Secretary of State

MISO RESPONSES TO ENERGY RESOURCES PLANNING TASK FORCE QUESTIONS

Question NO.: 1

Having had some time to do an analysis of your operations since the February winter event, could your organization provide a brief summary of your role in addressing the power outages during the February winter event.

RESPONSE: **See below** ☒ **See attached** ☐
RESPONSE DATE: **April 30, 2021**

As the Regional Reliability Coordinator and Balancing Authority, MISO is responsible for maintaining the safe, reliable operation of the Bulk Electric System (BES) in our operational control.

The arctic weather winter storm during the week of February 15 caused multiple days in sub-freezing temperatures and double-digit snowfall topped with significant ice accumulation, which made for a complex and unique event. MISO began its preparations several days before by declaring a Cold Weather Alert and Conservative Operations. These actions allowed MISO and its members to identify all available generation and known transmission issues before the event. All Real-Time Operations Alerts and Declarations are available on MISO's public website.

In addition to the operational alerts, MISO staff held daily calls throughout the event with operations, communications, and regulatory representatives of its affected members. There were four transmission-related load shed events and one Maximum Generation Load Shed event during the winter weather event:

- 2/15/21 Local Transmission Emergency – 800 MW, Western Load Pocket (SE Texas)
- 2/16/21 Local Transmission Emergency – 300 MW, Western Load Pocket (SE Texas)
- 2/16/21 Transmission System Emergency – 1000 MW, North-Central Louisiana
- 2/16/21 Transmission System Emergency – 130 MW, South-Central Illinois
- 2/16/21 Maximum Generation Event Step 5 – 700 MW, South Region (All South LBAs)

February 15, 2021
MISO declared a Local Transmission Emergency due to generation and transmission losses in Southeast Texas, also known as the Western Load Pocket. These led to a localized load shed event affecting Entergy Texas customers in the Dayton, Texas area. MISO had also begun to escalate through its Maximum Generation Alert and Event steps.

February 16, 2021
Morning – Due to worsening conditions on the Bulk Electric System, three transmission events temporarily interrupted power to parts of Southeast Texas, North-Central Louisiana, and South-Central Illinois.

Afternoon – Further issues began to emerge throughout the afternoon as 2500 MW of generation dropped between 2:30 and 5:00 pm central time.

Evening - MISO declared a Max Gen Event 2c at 5:37 pm. central time, requesting public appeals for conservation. Realizing the grid's stability was in danger and unable to import the needed energy to meet demand, MISO operators notified its Load Balancing Authorities (LBAs) in the South Region to collectively shed 700 MW of load to avoid wide-spread cascading outages.

LBAs in Arkansas, Mississippi, Texas, and Louisiana were each given their pro-rata share of load to shed from their systems. The entities then determined which customers would be impacted. The entire load shed event lasted two hours and twenty minutes. This marks the second system load shed event in MISO's history (Hurricane Laura was the first).

While control room operators were managing generation and transmission issues, other MISO staff worked with state and local officials to communicate and emphasize the importance of assisting fuel supply to the plants. Those activities included helping get roadways cleared for fuel delivery and emergency declarations so plants could operate.

Question NO.: 2

Did your existing emergency procedures work as intended and are there any improvements you will be implementing to deal with similar power shortages due to potential future events?

RESPONSE:	**See below** ☒	**See attached**	☐
RESPONSE DATE:	**April 30, 2021**		

MISO's procedures operated as designed. In addition, MISO is currently conducting an analysis of the causes and impacts of the Winter Storm, which will be finalized as a report by the end of May 2021. MISO is planning to provide the report publicly and it will be made available for stakeholders.

Question NO.: 3

Unlike the events in Texas, as discussed in your testimony to the Energy Committees, the larger multi-state system operated by SPP and MISO appeared to be a reason the power outages in Arkansas were not as extensive.

a. Describe your preparedness and allocation process for critical energy resources during extreme events.
b. Could you elaborate on why that structure was beneficial and how the two System Operators worked together to minimize the outages in Arkansas.

RESPONSE:	**See below** ☒	**See attached**	☒
RESPONSE DATE:	**April 30, 2021**		

a. MISO took the following operational steps ahead of the Cold Weather Event:
   - Requested members update offers and ensure Load Modifying Resource (LMR) data is accurate.
   - Extended or adjusted the start/stop times for generation resources in the South region to aid in availability during peak load times.
   - Confirmed planned outage and return-to-service dates/times for generation and transmission outages.
   - Committed additional generation with lead time enabling members to procure fuel.
   - Continued discussions with our members in the South Region about the potential need for a public appeal, if necessary, and coordinated communications with those members.

When developing Operating Procedures, Business Practice Manuals (BPMs), stakeholder presentations and various reports/studies, MISO considers industry best practices, such as the North American Transmission Forum (NATF) and relevant North American Energy Reliability Corporation (NERC)[1] documents.

To provide some background, MISO assisted the Federal Energy Regulatory Commission (FERC), NERC, and the regional reliability entities to provide information relevant to the January 17, 2018 cold weather event that was experienced across the South Central United

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[1]*The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves nearly 400 million people.*

States. MISO made several positive changes as a result of the January 2018 event, including improved coordination with neighboring grid operators. One of the most notable enhancements was the development of a joint Regional Transfer Operations Procedure (RTOP) that is now used to govern MISO's use of the Regional Directional Transfer (RDT) with SPP. MISO carefully reviewed the 13 industry recommendations that came out of "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018" report, several of which reaffirmed recommendations that were included in the "Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011" (2011 FERC-NERC Southwest Task Force (SWTF) report. Additionally, MISO hosted staff from FERC, NERC, and the regional reliability entities on October 21-22, 2019 to further review MISO's overall cold weather preparedness and response to the cold weather report findings.

- MISO has multiple avenues for providing information to stakeholders on winter preparation including periodically updated reports/assessments/workshops and standing information on www.misoenergy.org.

Readiness Forum/Workshops

MISO conducts an annual Winter Readiness Forum/Workshop. The most recent one was conducted on October 27, 2020. In addition, MISO will hold a Summer Readiness Forum/Workshop on May 4, 2021.

These annual MISO workshops provide a forum for MISO stakeholders to come together and share information on a variety of topics related to winter and summer readiness.

NERC Lessons Learned Review

MISO has a newer effort to review NERC Lessons Learned. This occurs in the MISO stakeholder Reliability Subcommittee approximately once per quarter. A particular NERC Lesson Learned is selected in collaboration with MISO stakeholders. To date, two presentations have been conducted, one of which was related to cold weather lessons learned.

"Generator Performance During Severe Cold Temperatures in 2019 Lessons Learned Update" was discussed at the Reliability Subcommittee on September 3, 2020 and was related to NERC Lesson Learned LL20200601 "Unanticipated Wind Generation Cutoffs during a Cold Weather Event."

Winter Resource Assessment

MISO also conducts annual seasonal assessments, including the most recent 2020-21 Winter Resource Assessment to determine if adequate resources are projected to be available to cover demand and outages.

MISO's website on Winterization

MISO also maintains a webpage on weatherizing generating units at: https://www.misoenergy.org/markets-and-operations/reliability-information/winterization/ including MISO Winterization Guidelines page 4 of which contains links to various NERC webpages on winter preparedness. A copy of the MISO Winterization Guidelines is attached hereto as Exhibit 1.

- MISO conducts annual Generation Winterization and Gas Fuel Surveys. The winterization survey completed its second year and the gas fuel survey its seventh year in the fall/winter of 2020.

  For the 2020-21 winter season a summary of these surveys was presented to stakeholders at the Reliability Subcommittee on December 11, 2020.

- During real-time operation MISO monitors major gas pipeline availability for situational awareness. This is described in "Communications for Natural Gas Fuel Supply Availability" procedure SO-P-NOP-00-467. While Generation Operators/Market Participants are responsible for coordinating natural gas deliveries to their units, MISO will monitor relevant pipeline operating conditions for the benefit of MISO control center operations personnel. As noted in the procedure, MISO can also become aware of fuel supply issues through various internally generated reports and verbal communications by Market Participants.

- MISO has several Emergency Operating Procedures (EOPs) that are written to consider a variety of causes that could lead to the need to enter a particular EOP. In general, these procedures are written to address the reliability condition versus the reason the condition exists.

b. Having a significantly interconnected transmission system allows for entities like MISO and SPP to work together to take advantage of the diversity of load, weather and managed fleets to maximize the availability of resources to meet loads across very large regions. See also the response above to (a.), which also explains the improved coordination following the January 2018 event.

Question NO.: 4

As outlined in your testimony to the Energy Committee, the System Operators cooperated to provide assistance as necessary to assist the other System.

a. Were communication protocols in place prior to the February event for the System Operators to provide mutual assistance?
b. If not formal protocols, are there plans to establish more formal procedures between the System Operators in the future?

RESPONSE:	**See below** ☒	**See attached**	☐
RESPONSE DATE:	**April 30, 2021**		

a. Yes. MISO, its members, and its neighbors, including SPP, normally drill on emergency communications and regularly have to work together on day to day management of the systems, even under normal conditions. In addition to good communication during the event, MISO and others are required to follow NERC protocols which provide consistency in operations and expectations.

b. Every situation allows for new lessons learned on how we operate our systems, independently and in coordination. MISO will continue to review such events and improve how we communicate with our members and our neighbors.

Question NO.: 5

Given that communication between the System Operators is important, it is equally important to communicate with the public and affected parties of pending outages necessary to maintain the System.

a. Were the notification procedures in place at the time of the February event sufficient? What improvements to a notification process should be made?
b. When outages are necessary, who makes the determination which areas are required to shed load?
c. Are there protocols in place for determining which areas are chosen to shed load and/or consideration given to the types of facilities impacted?
d. Is there sufficient usage data to adequately determine the impact of outages in each area or on different types of infrastructure or facilities in those areas?
e. How does the end user appeal or request consideration of unique circumstances upon notification of service curtailment?

RESPONSE:	**See below** ☒	**See attached**	☒
RESPONSE DATE:	**April 30, 2021**		

a. Yes, and MISO's System Operations utilize the Energy Emergency Alert steps in its Capacity Emergency Procedures. These steps provide our members and neighboring Operators sufficient information to communicate system conditions.
Regarding public notifications, MISO utilized its designated communication channels to notify affected parties. This includes member company representatives (operations, regulatory, communications). MISO also provided messages via social media and added a "Current Grid Conditions" page to its Media Center as the primary location for public information.

   MISO executed its Crisis Communications plan and it worked as designed. However, we are always looking for opportunities to improve clarity and consistency as well as additional touch points for reinforcement. For example, MISO deployed its Mobile App in the first quarter. The operations notifications are also posted immediately to the site and pushed to the app.

b. MISO, as the Reliability Coordinator for its membership, is responsible for determining the need for load shed and directing it to the appropriate Local Balancing Authorities.

c. Yes, and consistent with its role as Reliability Coordinator and dependent upon the circumstances, MISO has protocols for identifying which LBAs should shed load. For example, in a local transmission emergency, MISO will direct a more targeted load shed to specific LBAs as was seen in four separate instances during the Arctic Weather Event, and those events limited the LBAs that were impacted. However, during the capacity deficiency event in the evening of 2/16, the existing protocol was to implement a pro-rata load shed based on the ratio of LBA load to system load at the time of the directive.

- MISO acts as the Balancing Authority (BA) with responsibility for declaring Load Shed Directives for Energy Emergency Alert Level 3 (EEA3) Events impacting areas within the MISO Balancing Authority Area. MISO Local Balancing Authorities (LBAs), such as the Entergy Arkansas Load Balancing Authority, are responsible for individual load shed programs, which take into account critical load identification, and perform the actual load sheds as directed by the MISO BA. Responsibilities around Firm Load Shed per Emergency Operating Procedure-011 (EOP-011) requirement 2.2.8 is delineated in the CFR00001. (The NERC Standard for Load Shed requirements is EOP-011, the Coordinated Functional Registration (CFR) delineates which parts of the NERC Requirements are the responsibility of MISO as BA and which are the responsibility of the LBAs as BAs).
- MISO procedural actions for EEA3 firm load sheds is included in MISO Procedure SO-P-EOP-002 MISO Market Capacity Emergency procedure section 4.2.13 shown below.
- Note that the respective LBA Firm Load Shed amounts are determined by applying a pro-rata share to each applicable LBA within the defined Event Area. For example, if the Event Area required 100 MW of load shed, and a specific LBA's load at the time of the Load Shed Directive was 15% of the Event Area load, then that LBA would be responsible for 15 MW of load shed.)
-

4.2.13 Max Gen Event Step 5 - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 5 or escalating from a Max Gen Alert/Warning or lower Event step, THEN **DECLARE** Max Gen Event Step 5 and EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions.

SM **Note**

Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment provides additional information regarding sharing of load shedding with Slice of System PPAs.

2. **DETERMINE** manual Load Shedding requirements.

SM **Note**

Issuing Emergency Operating Instructions for firm Load shed is based on the ratio of LBA forecasted or actual Load to the total forecasted or actual Load of the declaration area, taking into account applicable transmission security requirements.

3. **ISSUE** Emergency Operating Instructions to LBAs, in declaration area, of MW amounts of load to shed via MCS Firm Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions.

- LBA actions for EEA3 firm load shed directives received from the MISO BA is included in MISO Procedure SO-P-EOP-002 Market Capacity Emergency procedure section 4.3.11. (Note that each individual LBA has internal procedures for its own specific load shed processes).

4.3.11 Max Gen Event Step 5 - MISO Stakeholder Actions

LBA 1. **SHED** firm Loads per MISO issued Emergency Operating Instruction. [ ]

LBA 2. **CONFIRM** actions taken with MISO RC via MCS Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions. [ ]

More information about MISO's operating procedures during emergency or abnormal operating situations can be found in the document attached hereto as Exhibit 2.

d. MISO does not direct Load Serving Entities (LSEs) to shed load; MISO directs the Local Balancing Authorities (LBAs) to shed load and it is the responsibility of the LBA to work with the LSEs in its area on coordination of load shed plans. MISO's visibility is limited to current system-wide situational awareness on the demand and resource balance and, if the system is at risk, the amount of load that would need to be shed to maintain and reliably operating the bulk electric system.

e. MISO does not have direct visibility to the distribution grid. Because of this, it is MISO's role to direct the LBA load shed and it is up to the LBA to identify the distribution circuits impacted.

Question NO.: 6

Are there changes that integrated system operators need to consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event?

a. If so, what changes would you recommend?
b. Are there constraints in place from Federal Energy Regulatory Commission or North American Electric Reliability Corporation that would prevent implementation of such changes?

RESPONSE:	**See below** ☒	**See attached**	☐
RESPONSE DATE:	**April 30, 2021**		

a. MISO is always open for continuous improvement, but at this time we do not envision any changes to our dispatch process. Charging of facilities would be managed through normal market processes and it is up to each market participant to dictate how those assets will be offered into the system. Current systems, along with planned improvements to meet future FERC mandated storage participation in wholesale markets should provide for such energy management.

b. FERC (and MISO) have a variety of pending dockets that could potentially impact storage technologies. MISO is also focused on its Reliability Imperative to broadly address the complex and urgent challenges to electric system reliability in the MISO Region. More information can be found at the following website: https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-reliability-imperative/

Question NO.: 7

Are there any recommendations or areas of further investigation that your organization would like to bring to the attention of the Task Force with regard to addressing energy supplies during future events?

RESPONSE:	**See below** ☒	**See attached**	☐
RESPONSE DATE:	**April 30, 2021**		

- Efforts to continue to foster and enhance preparedness as we have discussed in question #3, as well as continue the high level of coordination with our neighbors as referenced in our response to question #4.
- Consider formalizing and expanding the ad hoc call (discussing securing fuel for certain generation facilities) into a leadership planning group that entails both Public and Private Organizations to cover impacts of extreme events. Those that were involved on the February 17th call were as follows:
-

Government

  - AR Governor's Office – Caleb Stanton
  - AR Public Service Commission – Chairman Ted Thomas
  - AR Economic Development Council – Mike Preston
  - Little Rock Mayor – Frank Scott
  - Department of Emergency – Scott Bass
  - Arkansas Research Alliance – Jerry Addams
  - State Police Colonel – Colonel Bill Bryant

Electric Utility Companies

  - Entergy – CEO Laura Ladeaux, SVP Charles Hall,
  - AECC – CEO Buddy Hasten & SVP Kirkley Thomas
  - MISO – Executive Director, Daryl Brown
  - SPP – Mike Ross

MISO is currently conducting an analysis of the causes and impacts of the Winter Storm, which will be finalized as a report by the end of May 2021. MISO is planning to provide the report publicly at a workshop currently planned for early June 2021 and the report will be made available for stakeholders.

EXHIBIT 1

MISO WINTERIZATION GUIDELINES

MISO WINTERIZATION GUIDELINES

UPDATED 10/23/2018

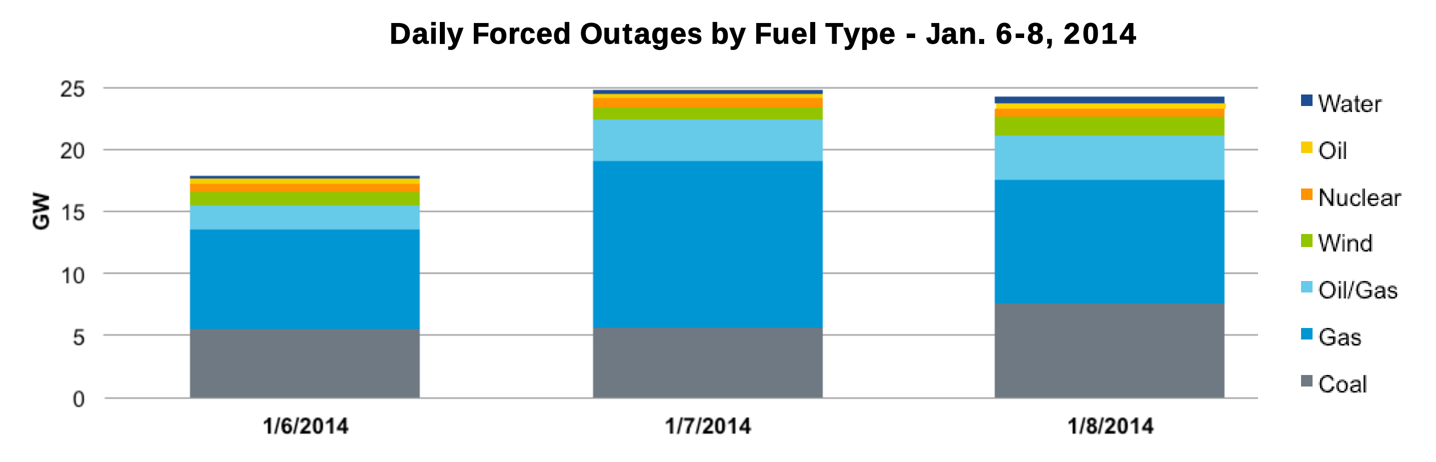
MISO

MISOENERGY.ORG

I. Introduction

Extreme winter conditions can contribute to significant losses of electric generation through a variety of factors. Cold temperatures can freeze equipment for various types of electric generators. Frozen transportation equipment and facilities can inhibit MISO generators from obtaining fuel.

The "Polar Vortex" event of 2014 culminated in an all-time MISO winter peak of over 109,000 MW. During this time, up to approximately 25,000 MW/day of capacity, not including derates, was forced offline due to weather related outages. These types of "forced outages," are not uncommon during extreme winter events where frigid temperatures can impact the operability of electric generators of all technology and fuel types. Coal generators took outages and capacity derates due to mechanical failures and fuel issues, such wet or frozen coal. Wind capacity also decreased with heavy snowfall and turbine icing. The facilities that were most impacted by the severe weather were natural gas units. Up to approximately 17,000 MW/day of gas-fired capacity (Gas and Oil/Gas classifications), was forced offline due to weather-related transportation restrictions, fuel line freezing, and other mechanical issues.



Source: 2013-2014 MISO Cold Weather Operations Report, MISO, November 2014

II. MISO Winterization General Guidelines

A. Evaluation of Potential Problem Areas

MISO believes that plant operations personnel should evaluate all equipment that has the potential to do the following:

1) Initiate an automatic unit trip
2) Impact unit start-up
3) Cause damage to the unit
4) Adversely affect environmental controls that could cause full or partial outages
5) Adversely affect the delivery of fuel or water to the units
6) Create a weather related safety hazard

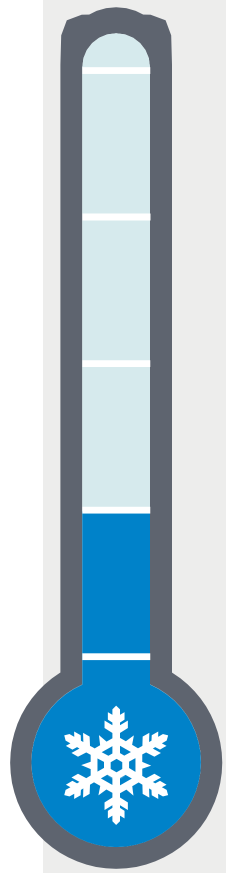
B. Detailed and Tested Winterization Plan

Power plant operators should create and have on hand a detailed winterization plan that covers preparations and procedures for freezing conditions. Weatherization arrangements should be developed by MISO generator operators for plant personnel to complete ahead of frigid weather conditions. In addition to pre-winter preparations, plant personnel training should be conducted well before winter begins. Lastly, weatherization equipment, such as heat trace systems, should be tested regularly ahead of winter.

C. Critical Instrument and Equipment Protection

Generator operators should evaluate and test secondary fuel capabilities (such as heating oil) ahead of winter operations. They should also ensure that all critical site specific problem areas have adequate protection to ensure operability during a severe winter weather event. Some examples of weatherization protection measures are as follows:

1) **Heat Trace**
    i. Heat trace elements should be well insulated and correctly installed on power plant equipment in order to keep stations from freezing.
    ii. Wiring on heat trace panels should be inspected and maintained to prevent deterioration and inoperability.
2) **Wind Break**
    i. Temporary wind walls must be appropriately installed in order to disallow cold air to flow into plant.
    ii. Additional protection on plant scaffolding floors can prevent a tunneling affect that could freeze equipment.
3) **Insulation**
    i. Insulation must be inspected for holes and maintained in order to keep equipment from freezing.
    ii. Properly installed and insulated weather barriers can prevent entry of cold air into plant.
4) **Instrument Cabinet Heaters and Insulation**
    i. Heat instrument cabinets should be insulated and warmed with acceptable devices (e.g. 60 watt bulb).
5) **Freeze Protection Equipment**
    i. Freeze protection equipment, such as temporary heaters, should be onsite and adequately tested ahead of extreme cold weather events.



D. Fuel Availability Considerations

MISO market participants are responsible to ensure fuel availability and deliverability to their generators. For coal units, plant operators should ensure that the onsite coal pile is kept from freezing during times of frigid temperatures. In addition, in advance of winter conditions, coal generators should confirm that the fuel supply is adequate and transportation is reliable.

For natural gas generators, market participants should review their individual transportation contracts to ensure that they have satisfactory means in which to deliver their fuel. These contractual characteristics include transportation firmness, storage rights, and gas services, such as no-notice and non-ratable agreements. In addition to primary fuel, natural gas units who hold dual fuel, most notably oil backup, should confirm that the plant has suitable backup fuel onsite and should ensure that the alternative fuel can successfully run the generator, through testing or other means.

E. NERC Reliability Guidelines and Procedures for Winterization

MISO advises generator operators to utilize NERC's winter generator reliability guidelines when preparing for and operating in severe cold weather conditions. These attached guidelines and procedures, titled *NERC Reliability Guideline – Generating Unit Winter Weather Readiness – Current Industry Practices and Elements of a Winter Weather Preparation Procedure Version 2* (Attachments 1 and 2), can be applied by plant operators to prepare units for winter operations. MISO understands that these NERC guidelines may be updated or revised from time to time and advises generator operators to follow the most up to date guidelines. These can be found in the below resources hyperlink under *NERC Reliability Guidelines*.

Resources

1. **NERC Winter Preparedness**

   https://www.nerc.com/pa/rrm/ea/Pages/Cold-Weather-Training-Materials.aspx

2. **NERC Reliability Guidelines**

   http://www.nerc.com/comm/OC/Pages/Reliability-Guidelines.aspx

3. **Reliability First Cold Weather Preparedness – Plant Winterization Visits ReliabilityFirst & Texas RE Lessons Learned, Best Practices & Recommendations**
   https://www.rfirst.org/KnowledgeCenter/Risk%20Analysis/ColdWeather/Pages/ColdWeather.aspx

4. **2013-2014 MISO Cold Weather Operations Report**

   https://cdn.misoenergy.org/2013-2014%20Cold%20Weather%20Operations%20Report103558.pdf

ATTACHMENT I

NERC RELIABILITY GUIDELINE

GENERATING UNIT WINTER WEATHER READINESS – CURRENT INDUSTRY PRACTICES
Version 2

I.	II.	III.	IV.	V.	VI.	VII.
Safety	Management Roles and Expectations	Processes and Procedures	Evaluation of Potential Problem Areas	Testing	Training	Winter Event Communications

Preamble:

The NERC Operating Committee (OC), Planning Committee (PC) and Critical Infrastructure Protection Committee (CIPC) develop Reliability (OC and PC) and Security (CIPC) Guidelines, which include the collective experience, expertise and judgment of the industry. The objective of the reliability guidelines is to distribute key practices and information on specific issues critical to promote and maintain a highly reliable and secure bulk power system (BPS). Reliability guidelines are not binding norms or parameters to the level that compliance to NERC's Reliability Standards are monitored or enforced. Rather, their incorporation into industry practices is strictly voluntary. Reviewing, revising, or developing a program using these practices is highly encouraged.

Purpose:

This reliability guideline is applicable to electricity sector organizations responsible for the operation of the BPS. Although this guideline was developed as a result of an unusual cold weather event in an area not normally exposed to freezing temperatures, it provides a general framework for developing an effective winter weather readiness program for generating units throughout North America. The focus is on maintaining individual unit reliability and preventing future cold weather related events. This document is a collection of industry practices compiled by the NERC OC. While the incorporation of these practices is strictly voluntary, developing a winter weather readiness program using these practices is highly encouraged to promote and achieve the highest levels of reliability for these high impact weather events.

Assumptions:

A. Each BPS Generator Owner (GO) and Generator Operator (GOP) is responsible and accountable for maintaining generating unit reliability.

B. Balancing Authorities (BAs) and Market Operators should consider strategies to start-up and dispatch to minimum load prior to anticipated severe cold weather units that are forecasted to be needed for the surge in demand, since keeping units running through exceptional cold snaps can be accomplished much more reliably than attempting start-up of offline generation during such events. Entities should develop and apply plant-specific winter weather readiness plans, as appropriate, based on factors such as geographical location, technology and plant configuration.

Guideline Details:

An effective winter weather readiness procedure, which includes severe winter weather event preparedness, should generally address the following components: (I) Safety; (II) Management Roles and Expectations; (III) Processes and Procedures; (IV) Evaluation of Potential Problem Areas with Critical Components; (V) Testing; (VI) Training; and (VII) Communications.

I. Safety

Safety remains the top priority during winter weather events. Job safety briefings should be conducted during preparation for and in response to these events. Robust safety programs to reduce risk to personnel include identifying hazards involving cold weather such as personnel exposure risk, travel conditions, and slip/fall issues due to icing. A Job Safety Analysis (JSA) should be completed to address the exposure risks, travel conditions and slips/falls related to icing conditions. Winter weather Alerts should be communicated to all impacted entities. A Business Continuity and Emergency Response Plan should also be available and communicated in the event of a severe winter weather event.

II. Management Roles and Expectations

Management plays an important role in maintaining effective winter weather programs. The management roles and expectations below provide a high-level overview of the core management responsibilities related to winter weather preparation. Each entity should tailor these roles and expectations to fit within their own corporate structure.

A. Senior Management

1) Set expectations for safety, reliability, and operational performance.
2) Ensure that a winter weather preparation procedure exists for each operating location.
3) Consider a fleet-wide annual winter preparation meeting, training exercise, or both to share best practices and lessons learned.
4) Share insights across the fleet and through industry associations (formal groups or other informal networking forums).

B. Plant Management

1) Develop a winter weather preparation procedure and consider appointing a designee responsible for keeping this procedure updated with industry identified best practices and lessons learned.
2) Ensure the site specific winter weather preparation procedure includes processes, staffing plans, and timelines that direct all key activities before, during and after severe winter weather events.
3) Ensure proper execution of the winter weather preparation procedure.
4) Conduct a plant readiness review prior to an anticipated severe winter weather event.
5) Encourage plant staff to look for areas at risk due to winter conditions and bring up opportunities to improve readiness and response.
6) Following each winter, conduct an evaluation of the effectiveness of the winter weather preparation procedure and incorporate lessons learned.

III. Processes and Procedures

A winter weather preparation procedure should be developed for seasonal winter preparedness. Components of an effective winter weather preparation procedure are included as Attachment 1.

After a severe winter weather event, entities should utilize a review process to formally recognize procedural strengths, evaluate improvement opportunities, and identify and incorporate lessons learned within applicable procedures. Changes to the procedure and lessons learned must be communicated to the appropriate personnel.

IV. Evaluation of Potential Problem Areas with Critical Components

Identify and prioritize critical components, systems, and other areas of vulnerability which may experience freezing problems or other cold weather operational issues.

A. This includes critical instrumentation or equipment that has the potential to:

1) Initiate an automatic unit trip,
2) Impact unit start-up,
3) Initiate automatic unit runback schemes or cause partial outages,
4) Cause damage to the unit,
5) Adversely affect environmental controls that could cause full or partial outages,
6) Adversely affect the delivery of fuel or water to the units,
7) Cause operational problems such as slowed or impaired field devices, or
8) Create a weather-related safety hazard

B. Based on previous cold weather events, a list of typical problem areas are identified below. This is not meant to be an all-inclusive list. Individual entities should review their plant design and configuration, identify areas with critical components' potential exposure to the elements, ambient temperatures, or both and tailor their plans to address them accordingly.

1) Critical Level Transmitters

i. Drum level transmitters and sensing lines

ii. Condensate tank level transmitters and sensing lines

iii. De-aerator tank level transmitters and sensing lines

iv. Hot well level transmitters and sensing lines

v. Fuel oil tank level transmitters / indicators

2) Critical Pressure Transmitters

i. Gas turbine combustor pressure transmitters and sensing lines

ii. Feed water pump pressure transmitters and sensing lines

iii. Condensate pump pressure transmitters and sensing lines

iv. Steam pressure transmitters and sensing lines

3) Critical Flow Transmitters

i. Steam flow transmitters and sensing lines

ii. Feed water pump flow transmitters and sensing lines

iii. High pressure steam attemperator flow transmitters and sensing lines

4) Instrument Air System

i. Automatic blow downs, traps, dew point monitoring, and instrument air dryers are functioning correctly.

ii. Low point drain lines are periodically drained by operators to remove moisture during extreme cold weather.

5) Motor-Operated Valves, Valve Positioners, and Solenoid Valves

6) Drain Lines, Steam Vents, and Intake Screens

7) Water Pipes and Fire Suppression Systems[1]

i. Low/no water flow piping systems

8) Fuel Supply and Ash Handling

i. Coal piles and coal handling equipment

ii. Transfer systems for backup fuel supply

iii. Gas supply regulators, other valves and instrumentation (may require coordination with gas pipeline operator)

iv. Ash disposal systems and associated equipment

9) Tank Heaters

i. Conduct initial tests

ii.Check availability of spare heaters

iii. Record current tanks indicators for SBS injection systems, flue gas desulfurization systems, dibasic acid additives, mercury control additives, etc.

C. Potential vulnerabilities associated with emergency generators, including Blackstart Resources, should be evaluated when developing the site specific winter weather preparation procedure as they may provide critical system(s) backup.

V. Testing[2]

In addition to the typical problem areas identified above, emphasis should be placed on the testing of low frequency tasks such as startup of emergency generators, where applicable.

VI. Training

Coordinate annual training in winter specific and plant specific awareness and maintenance training. This may include response to freeze protection panel alarms, troubleshooting and repair of freeze protection circuitry, identification of plant areas most affected by winter conditions, review of special inspections or rounds implemented during severe weather, fuel switching procedures, knowledge of the ambient temperature for which the freeze protection system is designed, and lessons learned from previous experiences or the NERC Lessons Learned program.

A. Consider holding a winter readiness meeting on an annual basis to highlight preparations and expectations for severe cold weather.

B. Operations personnel should review cold weather scenarios affecting instrumentation readings, alarms, and other indications on plant control systems.

C. Ensure appropriate NERC Generation Availability Data Systems (GADS) coding for unit derates or trips as a result of severe winter weather events to promote lessons learned, knowledge retention, and consistency. Examples may include NERC GADS code 9036 "Storms (ice, snow, etc.)" or code 9040 "Other Catastrophe."

[1]For safety reasons, fire protection systems should also be included in this identification process. These problem areas should be noted in the site specific winter weather preparation procedure.

[2] ~~See Attachment 2, Section H "Special Operations Instruction" for more information~~

VII. Winter Event Communications

Clear and timely communication is essential to an effective program. Key communication points should include the following:

A. Before a severe winter weather event, plant management should communicate with their appropriate senior management that the site specific winter weather preparation procedure, checklists, and readiness reviews have been completed.

B. Before and during a severe winter weather event, communicate with all personnel about changing conditions and potential areas of concern to heighten awareness around safe and reliable operations.

C. Before and during a severe winter weather event, the affected entity(ies) will keep the BA up to date on changes to plant availability, capacity, or other operating limitations. Depending on regional structure and market design, notification to the Reliability Coordinator (RC) and Transmission Operator (TOP) may also be necessary.

D. After a generating plant trip, derate, or failure to start due to severe winter weather, Plant Management, as appropriate, should conduct an analysis, develop lessons learned, and incorporate good industry practices.

   1) This process should include a feedback loop to enhance current winter weather readiness programs, processes, procedures, checklists and training (continuous improvement).

   2) Sharing of technical information and lessons learned through the NERC Event Analysis Program or some other method is encouraged.

Related Documents and Links:

1. Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011, dated August 2011, Federal Energy Regulatory Commission and North American Electric Reliability Corporation
2. Winter Weather Readiness for Texas Generators, dated April 13, 2011, Calpine, CPS Energy, LCRA, Luminant, and NRG Energy
3. Electric Reliability Organization Event Analysis Process, dated January 2017, ERO Event Analysis Process and associated Lessons Learned
4. Previous Cold Weather Reports

Revision History:

Date	Version	Reason/Comments
12/03/2012	1.0	Initial Version – *Winter Weather Readiness* *(Approved by the Operating Committee March 5, 2013)*
06/05/2017	2.0	Three year document review per the OC Charter *(Approved by the Operating Committee August 23, 2017)*

ATTACHMENT 2

ELEMENTS OF A WINTER WEATHER PREPARATION PROCEDURE

A.	B.	C.	D.	E.	F.	G.	H.
Work Management System	Critical Instrumentation and Equipment Protection	Insulation, Heat Trace, and Other Protection Options	Supplemental Equipment	Operational Supplies	Staffing	Communications	Special Operations Instruction

This Attachment provides some key points to address in each of the winter weather preparation procedure elements, including severe winter weather event preparedness. These are not all inclusive lists. Individual entities should review their plant design and configuration, identify areas of potential exposure to the elements and ambient temperatures, and tailor their plans to address them accordingly.

A. Work Management System

1) Review Work Management System to ensure adequate annual preventative work orders exist for freeze protection, winter weather preparedness, or both.
2) Ensure all freeze protection, winter weather preparedness preventative work orders, or both are completed prior to the onset of the winter season.
3) Review Work Management System for open corrective maintenance items that could affect plant operation and reliability in winter weather and ensure that they are completed prior to the onset of the winter season.
4) As appropriate to your climate, suspend freeze protection measures and remove freeze protection equipment after the last probable freeze of the winter. This may be a plant specific date established by senior management.
5) Ensure all engineered modification and construction activities are performed such that the changes maintain winter readiness for the plant. Newly built plants or engineered modifications can be more susceptible to winter weather.

B. Critical Instrumentation and Equipment Protection

1) Ensure all critical site specific problem areas (as noted above in section III. Evaluation of Potential Problem Areas) have adequate protection to ensure operability during a severe winter weather event. Emphasize the points in the plant where equipment freezing would cause a generating plant trip, derate, or failure to start.
2) Develop a list of critical instruments and transmitters that require increased surveillance during severe winter weather events.

C. Insulation, Heat Trace, and Other Protection Options – Ensure processes and procedures verify adequate protection and necessary functionality (by primary or alternate means) before and during winter weather. Consider the effect of wind chill when applying freeze protection. Considerations include but are not limited to:

1) Insulation thickness, quality and proper installation

i. Verify the integrity of the insulation on critical equipment identified in the winter weather preparation procedure. Following any maintenance, insulation should be re-installed to original specifications.

2) Heat trace capability and electrical continuity/ground faults

i. Perform a complete evaluation of all heat trace lines, heat trace power supplies (including all breakers, fuses, and associated control systems) to ensure they maintain their accuracy. This inspection may include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation which could lead to the heat trace malfunctioning. Measure heat trace amperage and voltage, if possible, to determine whether the circuits are producing the design output. If there are areas where heat tracing is not functional, an alternate means of protection should be identified in the winter weather preparation procedure.

ii. Evaluation of heat trace and insulation on critical lines should be performed during new installation, during regular maintenance activities, or if damage or inappropriate installation is identified (i.e., wrapped around the valve and not just across the valve body).

iii. Re-install removed or disturbed heat tracing following any equipment maintenance to restore heat tracing integrity and equipment protection.

iv. Update and maintain all heat tracing circuit drawings and labeling inside cabinets.

3) Wind breaks

i. Install permanent or temporary wind barriers as deemed appropriate to protect critical instrument cabinets, heat tracing and sensing lines.

4) Heaters and Heat Lamps

i. Ensure operation of all permanently mounted and portable heaters.

ii. Evaluate plant electrical circuits to ensure they have enough capacity to handle the additional load. Circuits with Ground Fault Interrupters (GFIs) should be continuously monitored to make sure they have not tripped due to condensation.

iii. Fasten heaters and heat lamps in place to prevent unauthorized relocation.

5) Covers, Enclosures, and Buildings

i. Install a box or enclosure with inside heat for some transmitters.

ii. Install covers on valve actuators to keep the actuator from accumulating ice.

iii. Inspect building penetrations, windows, doors, fan louvers, and other openings for potential exposure of critical equipment to the elements.

D. Supplemental Equipment – Prior to the onset of the winter season, ensure adequate inventories of all commodities, equipment and other supplies that would aid in severe winter weather event preparation or response, and that they are readily available to plant staff. Supplemental equipment might include:

1) Tarps

2) Portable heaters, heat lamps, or both

3) Scaffolding

4) Blankets

5) Extension cords

6) Kerosene/propane

7) Temporary enclosures

8) Temporary insulation

9) Plastic rolls

10) Portable generators

11) Portable lighting

12) Instrumentation tubing

13) Handheld welding torches

14) Ice removal chemicals and equipment

15) Snow removal equipment

16) Cold weather Personal Protective Equipment (PPE) as appropriate to the respective regions

E. Operational Supplies – Prior to the onset of a severe winter weather event, conduct an inventory of critical supplies needed to keep the plant operational. Appropriate deliveries should be scheduled based on the severity of the event, lead times, etc. Operational supplies might include:

1) Aluminum Sulfate

2) Anhydrous Ammonia

3) Aqueous Ammonia

4) Carbon Dioxide

5) Caustic Soda

6) Chlorine

7) Diesel Fuel

8) Ferric Chloride

9) Gasoline (Unleaded)

10) Hydrazine

11) Hydrogen

12) Lighter Oil (#2 Diesel)

13) Sulfuric Acid

14) Calibration Gases

15) Lubricating Oils

16) Welding Supplies

17) Limestone

F. Staffing

1) Consider enhanced staffing (24x7) during severe winter weather events.

2) Arrange for lodging and meals as needed.

3) Arrange for transportation as needed.

4) Arrange for support and appropriate staffing from responsible entity for plant switchyard to ensure minimal line outages.

G. Communications

1) Ensure appropriate communication protocols are followed during a severe winter weather event.
2) identify a back-up communication option in case the primary system is not working (i.e. satellite phone).
3) Ensure communication is discussed as part of the job safety briefing during a severe winter weather event.

H. Special Operations Instruction (just prior to or during a severe winter weather event)

1) Consider employing the "buddy system" during severe winter weather events to promote personnel safety.
2) Institute operator rounds utilizing cold weather checklists to verify critical equipment is protected – i.e. pumps running, heaters operating, igniters tested, barriers in place, temperature gauges checked, etc.
    i. Monitor room temperatures, as required. Instrumentation and equipment in enclosed spaces (e.g. pump rooms) can freeze.
3) Test dual fuel capability and ensure adequate fuel supply (where applicable).
4) Consider pre-warming, early start-up, or both of scheduled units prior to a forecasted severe winter weather event.
5) Run emergency generators immediately prior to severe winter weather events to help ensure availability. Review fuel quality and quantity.
6) Place in service critical equipment such as intake screen wash systems, cooling towers, auxiliary boilers, and fuel handling equipment where freezing weather could adversely impact operations or forced outage recovery.

MISO
WINTERIZATION
GUIDELINES

MISO

EXHIBIT 2

MISO OPERATING PROCEDURES

MISO Operating Procedures

MISO's carefully designed operating procedures ensure reliability and predictable outcomes during emergency or abnormal operating situations.

Protecting Reliability

To maintain the reliability of the electric system, MISO operates under a set of carefully designed operating procedures that define system conditions and guide system operator actions in a variety of conditions.

These procedures empower MISO to quickly adjust to system conditions as they unfold. For example, extreme weather patterns or unexpected increases or decreases in available electric generation can affect the balance of supply and demand on the transmission system.

Did you know?

- MISO has never issued a call for rolling brownouts or blackouts, despite some of the hottest summers on record in 2006 and 2012, and record cold during the polar vortex of 2014.
- To maintain reliability, Conservative and Emergency operating conditions require a successive series of remedial actions.
- MISO must implement emergency procedures to use demand management (load modifying) resources. There are more than 9,000 MW of these resources.

Operating Conditions

- **Normal Operations**: MISO's Normal Operating Procedures (NOPs) guide our operation of the bulk electric system and are used during normal grid operations or, in some instances, to prevent an emergency. NOPs mitigate risk, facilitate the reliable and efficient operation of the electric system, and ensure compliance with federal and state regulatory requirements, reliability standards, and MISO's Tariff and contractual agreements.
- **Abnormal Operations**: MISO utilizes Abnormal Operating Procedures (AOPs) for events that deviate from normal but do not put the electric system at risk. Examples include malfunctioning software systems or other infrastructure problems affecting MISO or its members. The procedures help mitigate further risk and may include, but are not limited to, the back-up process used when a particular system fails.
- **Conservative Operations**: If conditions warrant, MISO will carefully transition from normal operating conditions to Conservative Operations to prepare local operating personnel for a potential event, and to prevent a situation or event from deteriorating. During conservative operations, non-critical maintenance of equipment is suspended or in some cases, returned to service. Operating personnel throughout the affected area are also in a higher state of alert. Conservative operation declarations may be initiated due to system conditions including severe weather, hot/cold weather, or geo-magnetic disturbance warning.
- **Emergency Operations**: Emergency Operating Procedures (EOPs) guide system operator actions when an event occurs on the electric system that has the potential to, or actually does, negatively impact system reliability. Emergency Operating Procedures are communicated in escalating order as advisories, alerts, warnings, and events. Advisories are provided for situational awareness of potential limited operating capacity. Alerts define the affected area and call to temporarily suspend generation unit maintenance in the defined area. During warnings, MISO may require external capacity resources to be available, or may curtail non-firm energy sales. MISO issues Max Gen Events due to a shortage of capacity resources. **During Emergency Events, MISO utilizes Emergency Pricing, which affects ex-post pricing, not system commitment or dispatch. Emergency Pricing will only be implemented during Max Gen Warnings, and Events, which may be caused by forced outages, higher than projected load, or other circumstances.**

Reference Documents

Find MISO's Reliability Operating Procedures on the MISO website:

https://www.misoenergy.org/markets-and-operations/reliability-operating-procedures/

General Guide to MISO's Emergency Operations Messaging

MISO's Emergency Operations messages define the area(s) involved, duration, and projections of system conditions. The table below is a summary, and does not replace or redefine MISO's Emergency Operations messages.

Message	Communication Intent	Potential Member/MISO Actions
Conservative Operations Declaration	**Alert for Situational Awareness:** Reliability issue possible for defined area.	• Potentially suspend transmission maintenance • Review outage plans for deferral, cancellation
Hot Weather, Cold Weather or Severe Weather Alert	**Alert for Situational Awareness:** MISO could be approaching tight supply conditions.	• Review outage plans for deferral, cancellation
Capacity Advisory	**Advisory for Situational Awareness**: Potential for limited operating capacity margins (<5%) in the next 2-3 days.	• Update facility and generation outages, including de-rates • Update generation offers • Update Load Forecast Values • Update LMR Availability and Self Scheduled MW values • Update EDR offers
Min Gen Alert	**Alert for Situational Awareness:** MISO is forecasting a potential supply surplus.	• Prepare for de-commitment (taking generation off line), reduction in purchases or other actions
Max Gen Alert	**Alert for Situational Awareness:** MISO is forecasting a potential capacity shortage.	• Declare Conservative System Operations • Prepare for possible Max Gen Event
Max Gen Warning	**Warning to Prepare for Possible Event**	• Curtail non-firm exports • Schedule all available external resources into the MISO Market • Implement Emergency Pricing Offer Tier 1. This is an ex-post pricing change, and does not affect system commitment or dispatch.
Max Gen Event (Step 1)	**Actions Taken to Preserve Operating Reserves:** NERC Emergency Alert 1	• All available resources in use • Generators instructed to start off-line resources. • Use of reserves not yet implemented. • Emergency Pricing Offer Tier 1 is still effective.
Max Gen Event (Steps 2, 3, 4)	**Actions Taken to Preserve Firm Load:** NERC Emergency Alert 2 (Step 3 declaration)	• Implement demand management programs • Utilize Contingency Reserves • Purchase Emergency Energy • Issue Public Appeals • Prepare for possible firm load shed • Implement Emergency Pricing Offer Tier 2. This is an ex-post pricing change, and does not affect system commitment or dispatch.
Max Gen Event (Step 5)	**Event Occurring:** NERC Energy Emergency Alert 3	• Shed firm load • Rolling brownouts or blackouts for defined area • Emergency Offer Tier 2 is still effective.

MISO Operating Procedures

System Status Levels

MISO also issues color-coded System Status Levels (SSL) based on the severity of the impact to the bulk electric system. For more information, see MISO's Abnormal Operating System Status Levels Procedure, SO-P-AOP-00-203.

Operating Conditions			
SSL 0 **Low - Green**	**SSL Level 1** **Elevated - Yellow**	**SSL Level 2** **High - Orange**	**SSL Level 3** **Severe - Red**
Description: System status is normal. No adverse impacts.	**Description:** Short, minor impact to system, can be quickly remedied. **Examples**: Temporary infrastructure issue.	**Description**: Longer term, major impact to system, cause unknown. **Examples**: Loss of monitoring data or member infrastructure	**Description**: Major impact on MISO's ability to reliably operate system or market. **Examples**: Hardware failure, bomb threat, sabotage, control center evacuation

MISO Operating Procedures

MISO's carefully designed operating procedures ensure reliability and predictable outcomes during emergency or abnormal operating situations.

Protecting Reliability

To maintain the reliability of the electric system, MISO operates under a set of carefully designed operating procedures that define system conditions and guide system operator actions in a variety of conditions.

These procedures empower MISO to quickly adjust to system conditions as they unfold. For example, extreme weather patterns or unexpected increases or decreases in available electric generation can affect the balance of supply and demand on the transmission system.

Did you know?

- MISO has never issued a call for rolling brownouts or blackouts, despite some of the hottest summers on record in 2006 and 2012, and record cold during the polar vortex of 2014.
- To maintain reliability, Conservative and Emergency operating conditions require a successive series of remedial actions.
- MISO must implement emergency procedures to use demand management (load modifying) resources. There are more than 9,000 MW of these resources.

Operating Conditions

- **Normal Operations**: MISO's Normal Operating Procedures (NOPs) guide our operation of the bulk electric system and are used during normal grid operations or, in some instances, to prevent an emergency. NOPs mitigate risk, facilitate the reliable and efficient operation of the electric system, and ensure compliance with federal and state regulatory requirements, reliability standards, and MISO's Tariff and contractual agreements.
- **Abnormal Operations**: MISO utilizes Abnormal Operating Procedures (AOPs) for events that deviate from normal but do not put the electric system at risk. Examples include malfunctioning software systems or other infrastructure problems affecting MISO or its members. The procedures help mitigate further risk and may include, but are not limited to, the back-up process used when a particular system fails.
- **Conservative Operations**: If conditions warrant, MISO will carefully transition from normal operating conditions to Conservative Operations to prepare local operating personnel for a potential event, and to prevent a situation or event from deteriorating. During conservative operations, non-critical maintenance of equipment is suspended or in some cases, returned to service. Operating personnel throughout the affected area are also in a higher state of alert. Conservative operation declarations may be initiated due to system conditions including severe weather, hot/cold weather, or geo-magnetic disturbancewarning.
- **Emergency Operations**: Emergency Operating Procedures (EOPs) guide system operator actions when an event occurs on the electric system that has the potential to, or actually does, negatively impact system reliability. Emergency Operating Procedures are communicated in escalating order as advisories, alerts, warnings, and events. Advisories are provided for situational awareness of potential limited operating capacity. Alerts define the affected area and call to temporarily suspend generation unit maintenance in the defined area. During warnings, MISO may require external capacity resources to be available, or may curtail non-firm energy sales. MISO issues Max Gen Events due to a shortage of capacity resources. **During Emergency Events, MISO utilizes Emergency Pricing, which affects ex-post pricing, not system commitment or dispatch. Emergency Pricing will only be implemented during Max Gen Warnings, and Events, which may be caused by forced outages, higher than projected load, or other circumstances.**

Reference Documents

Find MISO's Reliability Operating Procedures on the MISO website:

https://www.misoenergy.org/markets-and-operations/reliability-operating-procedures/

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MISO

MISO Operating Procedures

General Guide to MISO's Emergency Operations Messaging

MISO's Emergency Operations messages define the area(s) involved, duration, and projections of system conditions. The table below is a summary, and does not replace or redefine MISO's Emergency Operations messages.

Message	Communication Intent	Potential Member/MISO Actions
Conservative Operations Declaration	**Alert for Situational Awareness:** Reliability issue possible for defined area.	• Potentially suspend transmission maintenance • Review outage plans for deferral, cancellation
Hot Weather, Cold Weather or Severe Weather Alert	**Alert for Situational Awareness:** MISO could be approaching tight supply conditions.	• Review outage plans for deferral, cancellation
Capacity Advisory	**Advisory for Situational Awareness:** Potential for limited operating capacity margins (<5%) in the next 2-3 days.	• Update facility and generation outages, including de-rates • Update generation offers • Update Load Forecast Values • Update LMR Availability and Self Scheduled MW values • Update EDR offers
Min Gen Alert	**Alert for Situational Awareness:** MISO is forecasting a potential supply surplus.	• Prepare for de-commitment (taking generation off line), reduction in purchases or other actions
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Max Gen Event (Step 1)	**Actions Taken to Preserve Operating Reserves:** NERC Emergency Alert 1	• All available resources in use • Generators instructed to start off-line resources. • Use of reserves not yet implemented. • Emergency Pricing Offer Tier 1 is still effective.
Max Gen Event (Steps 2, 3, 4)	**Actions Taken to Preserve Firm Load:** NERC Emergency Alert 2 (Step 3 declaration)	• Implement demand management programs • Utilize Contingency Reserves • Purchase Emergency Energy • Issue Public Appeals • Prepare for possible firm load shed • Implement Emergency Pricing Offer Tier 2. This is an ex-post pricing change, and does not affect system commitment or dispatch.
Max Gen Event (Step 5)	**Event Occurring:** NERC Energy Emergency Alert 3	• Shed firm load • Rolling brownouts or blackouts for defined area • Emergency Offer Tier 2 is still effective.

MISO Operating Procedures

System Status Levels

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Operating Conditions			
SSL 0 Low - Green	SSL Level 1 Elevated - Yellow	SSL Level 2 High - Orange	SSL Level 3 Severe - Red
Description: System status is normal. No adverse impacts.	**Description:** Short, minor impact to system, can be quickly remedied. **Examples:** Temporary infrastructure issue.	**Description**: Longer term, major impact to system, cause unknown. **Examples**: Loss of monitoring data or member infrastructure	**Description**: Major impact on MISO's ability to reliably operate system or market. **Examples**: Hardware failure, bomb threat, sabotage, control center evacuation

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Event Step 1a	Commit AME resources	As directed by MISO, LBAs/GOPs/MPs start AME Resources
Event Step 1b/EEA1	Declare EEA1	MPs review Offers and ensure all available Emergency ranges and Resources are offered
	Activate Emergency Maximum Limits	
Event Step 2a/EEA2	Declare EEA2	
	Implement Emergency pricing - Tier 2	
	Instruct Load to be reduced via LMMs - Stage 1 and LMRs	As directed by MISO, LBAs reduce load via LMM - Stage 1
	Implement LMRs	MPs implement LMRs via MCS-LMR Tool
Event Step 2b	Commit EDR Resources	As directed by MISO, MPs commit EDRs
Event Step 2c	Implement Emergency energy purchases	LBAs issue public appeals to reduce demand per internal procedures and OE-417 filings
	Instruct LBAs to issue Public Appeals	
		LBAs in defined Event area shall prepare to shed Load
Event Step 3a	Notify affected GOPs with Generator de-rates to request waivers	Affected GOPs dispatch de-rated Generators with waivers from government regulations
	Implement spinning and supplemental reserves	
Event Step 3b	Elevate identified Priority 6-NN tags	
	Instruct Load to be reduced via LMMs - Stage 2	Affected LBAs reduce load via LMM - Stage 2
Event Step 4a	Implement Reserve Call from CRSG	MPs review Offers and ensure all available Emergency ranges and Resources are offered
Event Step 4b	Implement Emergency energy purchases from neighboring BAs (Operating Reserves)	
Event Step 5/EEA3	Declare EEA3	
	Issue Emergency Operating Instruction to shed load	LBAs shed load per MISO and confirm action via MCS Load Shed Tool
	Set LMPs and MCPs to the VOLL	LBAs review OE-417 filing requirements

THE FEBRUARY ARCTIC EVENT

FEBRUARY 14-18, 2021

EVENT DETAILS, LESSONS LEARNED AND
IMPLICATONS FOR MISO's RELIABILITY IMPERATIVE

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THE FEBRUARY ARCTIC EVENT

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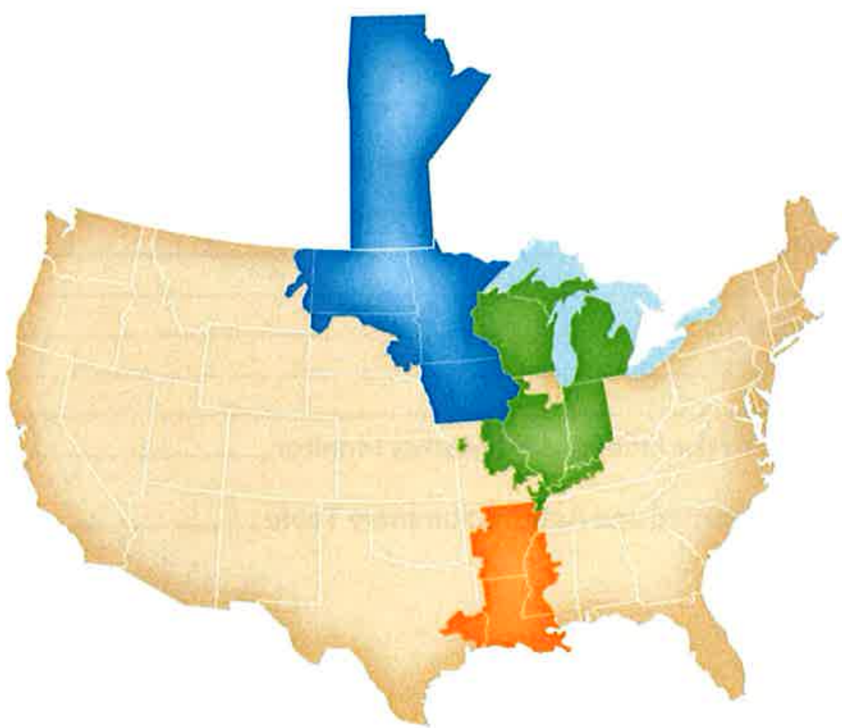
Table of Contents

About MISO

MISO is a 501(c)(4) not-for-profit social welfare organization, approved by FERC in 2001, with responsibility for ensuring the reliability of the high-voltage electric transmission system and facilitating the delivery of lowest-cost energy to consumers. The system that MISO manages is the largest in North America in terms of geographical scope, with 471 market participants serving about 42 million people across all or parts of 15 states and one Canadian province, stretching from Canada to the Gulf of Mexico. Our energy markets are also among the largest in the world, with more than $22 billion in annual gross market charges.

Currently, the MISO region contains almost 66,000 miles of high-voltage transmission, as well as nearly 199,000 megawatts of electricity generating capacity. MISO does not own any of these assets. Instead, with the consent of our asset-owning members and in accordance with our FERC-approved tariff, MISO exercises functional control over the region's transmission and generation resources with the aim of managing them in the most reliable and cost-effective manner possible. The MISO region is predominantly comprised of traditionally structured and state-regulated utilities.



Executive Summary

Introduction

MISO strives to be the most reliable, value creating Regional Transmission Organization. As such, MISO is committed to using all of the planning, market, and operational tools at our disposal to keep the grid reliable today while creating transparency towards future needs and maintaining and enhancing reliability. The collaborative work with our stakeholders gives us confidence that we will collectively continue to ensure reliability of the Bulk Electric System.

Like much of the energy industry, MISO faces a rapidly evolving grid. At the same time the resource mix is rapidly shifting away from dispatchable thermal units and increasingly toward variable resources such as renewables and Distributed Energy Resources (DERs) and the growth of electric vehicles and other sources of load is putting extra demand on the system. MISO is actively working on preparing the region for this resource portfolio change. Weather events have also been and continue to be an important element of ensuring reliability.

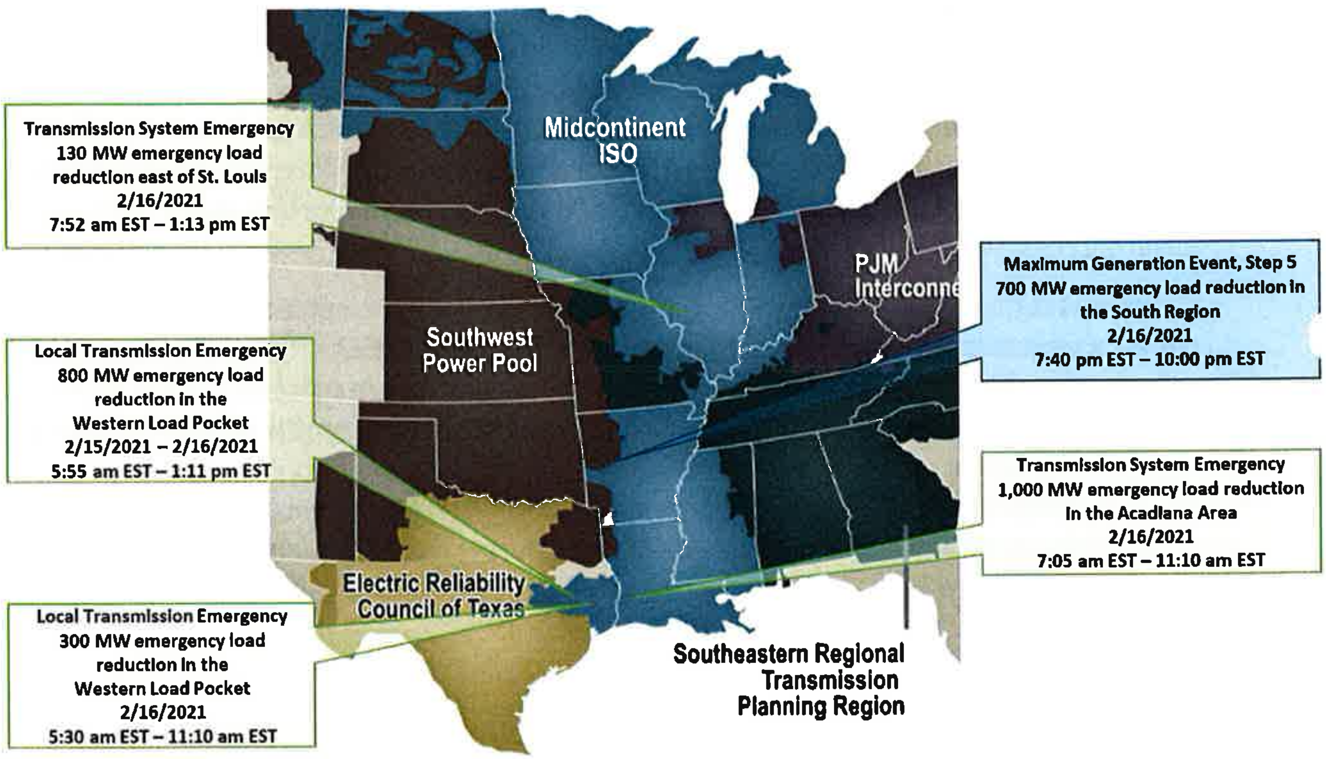
Extreme weather events like the February 2021 cold weather emphasize not only the necessary steps but the urgency with which we must move. MISO's Reliability Imperative – the actions that we are taking to ensure the current and future reliability of the grid – focuses on preparing the region for a future with a different risk profile stemming from a high penetration of renewables. The Reliability Imperative work is looking at enhancements to planning, markets, operations, and systems; changes that will also be needed to maintain reliability of the MISO region during more frequent extreme weather events in the future.

Arctic Event

During the week of February 15, 2021, cold weather impacted a large portion of the United States. MISO's region experienced unusually cold weather, especially in the southern states. High temperatures during the period were more than 30 degrees below average highs, while low temperatures were 20 to 30 degrees below average lows in much of the southern United States, making it one of the most extreme weather events in the last 30 years. These temperatures drove high demand for electricity while simultaneously reducing supply due to weather related generation performance issues and fuel availability. In addition, MISO's geographic location makes it a hub for large power flows across the system to serve electricity not just in its footprint but also in the neighboring systems such as the Southwest Power Pool (SPP). Supply shortage coupled with large power flows threatened reliability.

Throughout the extreme conditions MISO utilized numerous tools at its disposal – including operating policies and procedures covering a broad range of operating conditions, long-standing coordination with neighboring regions, like SPP and PJM – and leveraged the value of an expansive geography and diverse generation mix.

Ultimately, MISO and its members had to take emergency actions, including ordering emergency load reduction, which is a last resort tool needed in certain situations to prevent larger, uncontrolled outages. These actions ensured the reliability of the grid while limiting electricity interruptions to a handful of short duration events.



Note: time frames represent the duration from when emergency load reduction was ordered through release of the full amount of load

The challenges faced during this extreme weather event, including transmission emergencies and generator outages, are a stark reminder of the need to continue transforming to ensure the MISO Region is ready for the current and future challenges facing the industry. This is increasingly important as the region experiences more frequent challenging grid conditions, increasingly electrification, and an evolving resource mix that is becoming more dependent upon intermittent generation resources.

Summary of Arctic Event Activities

Preparations for the Arctic event began nearly a week before the worst of the weather hit the region. As MISO monitored the developing weather situation and gained increasing clarity about the timing and magnitude of cold temperatures, various operating procedures were implemented beginning on February 9 to ensure our members and others in the region were as prepared as possible. However, the most significant impacts to customers, including emergency load reductions, occurred February 15-16.

- **Eastern Texas:** In the early morning hours of February 15, snow and ice causing significant damage in eastern Texas. Two major transmission lines and two generators serving the area went offline. Power transfers to the area increased on remaining lines as MISO tried to deliver adequate energy to the impacted areas. However, due to the potential for overloading those transmission lines, which could cause instability and cascading outages, at 5:40 a.m. (EST) MISO declared a Local Transmission Emergency. Over the next two hours MISO instructed Entergy to reduce load by a total of 800 MW in part of Texas. Later in the day the two transmission lines were restored and MISO incrementally released the load reduction orders until all load was restored the afternoon of February 16.
- **Louisiana:** Early on February 16, with transmission and generation outages impacting parts of Texas, the east-to-west flows on the system were at risk of exceeding safe operating limits. As the morning load increased, between 7:00 a.m. and 7:31 a.m. MISO was forced to declare a Transmission System Emergency and instructed a total of 1,000 MW of emergency load reductions in North-Central Louisiana to keep flows under the transmission line limits. By 11:40 a.m. all load was restored and the emergency declaration was terminated.
- **Illinois:** On February 16, 2021, at 7:00 a.m., a Transmission System Emergency was declared in South-Central Illinois in response to concerns about transmission limit violations due to excessive east-to-west flows. This resulted in a "stranded capacity" scenario where adequate electricity was available, but it could not be moved to where it was needed. At 7:52 a.m., MISO directed Ameren to reduce load by 130 MW in South-Central Illinois to relieve electricity flows exceeding the system operating limits. The load was restored at 1:13 p.m.
- **System-Wide:** During the evening increase in electricity demand on February 16, 2021, multiple generators tripped offline in MISO's South Region. MISO declared a Maximum Generation Event at 6:35 p.m., committing Emergency Demand Response and coordinating with members to issue public appeals for energy conservation. A short time later, at 6:50 p.m.., MISO sought to temporarily increase the North-South

Regional Directional Transfer Limit in an effort to transfer more energy to MISO's South region. Unfortunately, the request could not be accommodated due to system overloads in neighboring systems. Realizing the grid's stability was in danger and being unable to move the needed energy to meet demand, at 7:40 p.m. MISO declared a Maximum Generation Event Step 5 and called for a 700 MW pro-rata emergency load reduction across MISO South Local Balancing Authorities. These emergency load reductions ended at 10:00 p.m. There were no further emergency load reductions and the Arctic Event officially ended when the last alert was terminated on February 20.

Key Takeaways

This event highlights the importance of challenges in delivering electricity, especially when it is needed most. Here are the 5 key takeaways.

1. Generation performance is critical, even when not experiencing extreme weather. MISO is counting on the generation to meet its commitment of delivering energy when it says it will be available. For the most efficient and reliable delivery of electricity we need sufficient generation to be available at the right times. While this is no easy task during normal operations, extreme weather events cause even greater negative impacts on generation performance because of issues like unexpected weather-related generator outages or fuel delivery challenges. Winterization to protect generation and fuel supplies from extreme weather can mitigate this risk but MISO and its members must assess and establish certain criteria. For instance, to what extreme temperature must generators be prepared to operate, how does MISO ensure consistency amongst similarly situated generation, and whose role it is to establish and verify such requirements? Finally, in cases where MISO does not have sufficient generation or when transmission lines are overloaded, emergency load reduction is the essential tool of last resort that can be used to prevent uncontrolled cascading outages. The industry needs to consider seasonal specific load reduction protocols, as the needs and constraints are different between winter and summer and any emergency load reduction events create significant hardship in affected areas.

2. Resource adequacy planning needs to be refined. Historically, tight supply and demand conditions typically only occurred on a few peak days in the summer, but today MISO experiences such conditions with increasing frequency across all seasons. Changing from an annual to a seasonal resource adequacy construct will help address this new reality. Further, fuel availability varies over time, and how and who should ensure fuel availability must be considered in reliability planning. Furthermore, if fuel assurance is

required, how do we do so in the most cost-effective manner (e.g., annual firm fuel when the generator may only be needed a few times a year)?

3. Transmission is vital to moving electricity from where it is generated to where it is needed most. The MISO region had adequate supply during the Arctic Event, but transmission constraints, including overloaded lines and the Regional Dispatch Transfer Limits, hindered the ability to move energy to the specific areas where it was needed. MISO's transmission system also supported our neighbors during the Arctic Event, in particular with substantial power flowing from the east through MISO to support reliable and efficient operations in the Southwest Power Pool (SPP). In addition to new transmission capacity, improved interregional coordination and interconnection will bring significant benefits to facilitate reliability and efficiency.

4. Operations of the future will require improved tools and information. Given the rapid shift in resource portfolios, and the increase in challenging weather events, system planners need more detailed and complete data to support event and post-event analyses, planning, and modeling; control room personnel will need more timely, granular, and high-fidelity data to support real-time operation decisions, and operational tools such as parallel flow visualization to improve real-time control room decisions. Automation and advanced analytics techniques will be key in providing insights into upcoming uncertainties and Grid status. Such improvements will help mitigate some of the types of challenges experienced during the Arctic Weather event, such as effectively modeling and managing of the Regional Dispatch Transfer Limits.

5. Reliability is the outcome of many years of forward-looking planning and decisions. Many entities, from regulatory bodies, members, market participants to end-use customers, have key roles in accomplishing this work. These roles need to be reviewed and adjusted to ensure that we collectively ensure continued reliability. As an example, Regional Transmission Organizations like MISO might not be in the best position to monitor or verify weatherization of the generation fleet. They could, however, help with analysis or provide input into the weatherization requirements needed to further reliability. MISO looks forward to the support and alignment of other entities to ensure the right roles and responsibilities for all involved.

MISO is committed to working collaboratively with its members, regulators, and other stakeholders to address these key takeaways. We invite all stakeholders to review and discuss these takeaways at the upcoming workshop and throughout the coming months.

Report Outline

This report begins with a description of the weather event and a detailed narrative of the impacts of that weather on the MISO system.

Next, the report covers topical areas with a more detailed description of MISO's response to the Arctic Event including lessons learned, and MISO's actions to address those lessons learned.

MISO has organized the topical discussions in rough chronological order where possible, followed by some cross-cutting areas:

- Planning, including both transmission and markets
- Preparation, including seasonal and event preparation and weather forecasting
- Operations, including Emergency Load Reduction and Regional Directional Transfer, Pricing, and Staffing and Tools
- Credit / Collateral
- Communication

The report identifies 20 lessons learned and over 35 actions, which are summarized in the Appendix.

The final section of this report includes MISO's responses to the findings from the Independent Market Monitor.

Event Narrative

Weather

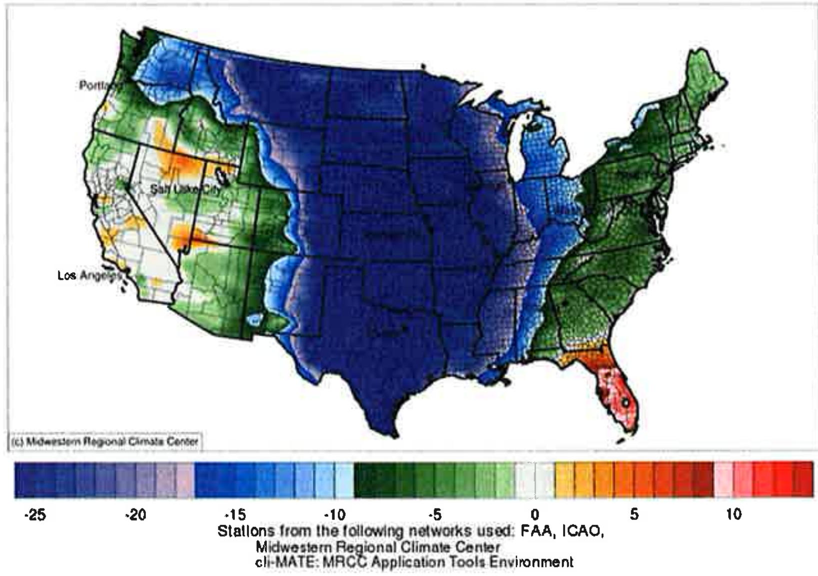
Beginning in early to mid-January 2021, the Polar Vortex[1] over the Arctic became destabilized, putting major population centers across the Northern Hemisphere at risk for cold air outbreaks. Ultimately, two concurrent weather events resulted in extreme weather conditions for much of the United States.

- On February 10, 2021, a winter storm formed north of the Gulf coast, dropping significant amounts of sleet and ice on many states in the Deep South and the Ohio Valley, including Texas, Georgia, Louisiana, Arkansas, Tennessee, as well as states on the East Coast. By mid-February, the weather pattern was oriented so that the core of the arctic air was directed towards central North America.
- Concurrently, the arctic air from the destabilized Polar Vortex also led to anomalous cold across the Plains and Midwest from February 12th-18th. This unusual weather pattern resulted in another winter storm that moved through the MISO South and Central Regions producing heavy snow and ice accumulation. The February 13th–17th, 2021 North American winter storm was a major winter and ice storm that started in the Pacific Northwest and quickly moved into the Southern United States, before moving on to the Midwestern and Northeastern United States a couple of days later. In the South, many cold temperature records were broken, driving winter peak loads close to the typically higher summer peak levels.

[1] The polar vortex is the large area of low pressure and cold air surrounding each of the Earth's poles. When conditions are right, the extreme cold air extend much farther from the poles than usual, significantly cooling large portions of the hemisphere for weeks or even months.

Average Temperature (°F): Departure from 1981-2010 Normals

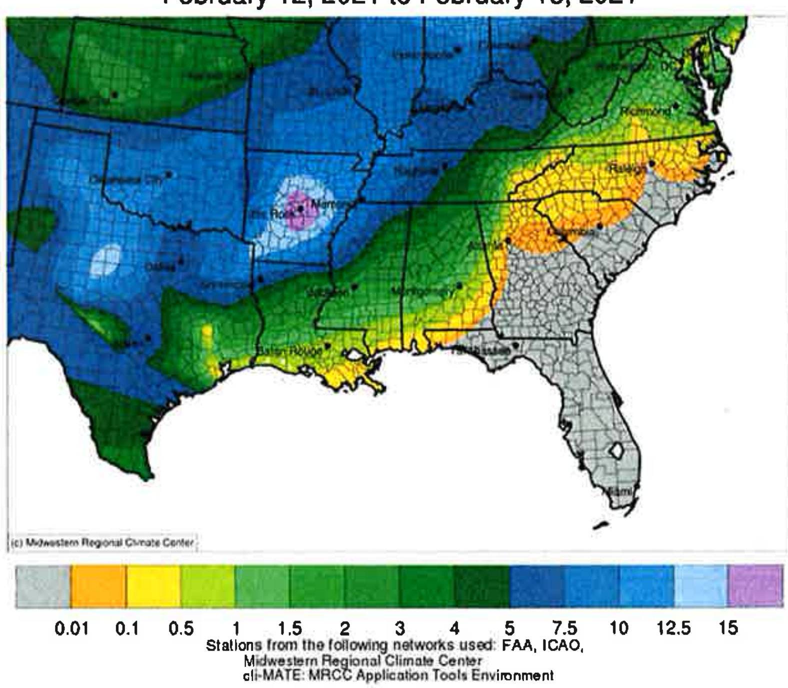
February 12, 2021 to February 18, 2021



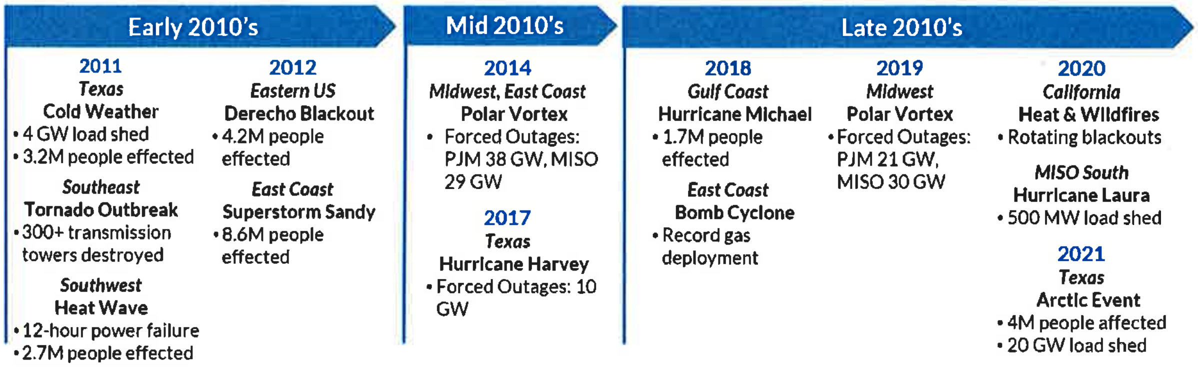
This storm, along with various other storms from the previous two weeks, resulted in over 75% of the contiguous U.S. being covered in snow.

Accumulated Snowfall (in)

February 12, 2021 to February 18, 2021



MISO has observed an uptick in severe weather events that have impacted electric reliability, both within MISO and across the country.



A recent Electric Power Research Institute (EPRI) report has concluded that hurricanes are increasing in intensity and duration, extreme heat events are increasing in frequency and intensity, and cold events are increasing in frequency (though less cold on average).

Grid Impacts and Operation

Weather of this significance has wide-ranging implications for many aspects of society. One that can be adversely affected by severe weather conditions is the power industry. Because of the potential impacts to the grid, and subsequently to end-use customers, and the lead-times needed to ensure certain power plants are available, MISO begins preparations well in advance of severe weather events. This includes assessing weather forecasts and expected impacts to demand, generators and the transmission system, communicating with members and neighboring grid operators, and considering the need for actions to prepare the system.

In coordination with stakeholders, MISO has developed an extensive set of procedures – addressing a range of normal, abnormal, conservative, and emergency operating conditions – that direct certain actions based on established criteria to support grid reliability. Those that were utilized during this event are described here and the entire set of Reliability Operating Procedures can be found on the MISO website.

MISO generally utilizes Informational Advisories in advance of any declarations. These are used to communicate MISO's anticipation of a potentially challenging scenario in the near-future and any actions members should take to initiate preparedness and maximize our ability to collectively manage the situation.

Included in the Normal Operating Procedures is the Conservative Operations declaration. This step is used to provide an early indication to operating personnel that challenging system conditions are anticipated and that they should review outage plans with a goal of deferring, delaying or recalling any non-essential maintenance or testing. Similarly, Severe and Cold Weather Alerts are issued to notify members of potential challenges with energy generation or transmission resources associated with weather and to compel the review of outage plans and preparation for potential emergency conditions.

Emergency Operating Procedures address situations that have the potential to, or actually negatively impact system reliability. These various procedures have multiple steps, with the most extreme being coordinated emergency load reductions, sometimes called load shed, where energy is intentionally cut off to selected areas to prevent a more severe, uncontrolled power outage.

One such emergency procedure is a Transmission System Emergency, used when facing transmission system conditions that have the potential to exceed or have exceeded an Interconnection Reliability Operating Limit, and cannot be mitigated using normal procedures. Transmission System Emergency declarations are issued to mitigate the potential of violating a transmission line limit that could lead to instability, uncontrolled separation, or cascading outages impacting the Bulk Electric System.

Separate from MISO's procedures, NERC has three **Energy Emergency Alert (EEA)** levels to ensure consistent communication of energy emergencies across the Interconnection.

- EEA 1 — All available resources in use.
- EEA 2 — Load management procedures in effect.
- EEA 3 — Firm load interruption imminent or in progress.

Also in the emergency category are procedures focused on generating capacity challenges. The Market Capacity Emergency Procedure identifies roles and responsibilities and actions for parties to take during events. There are a number of steps within the procedure with implementation generally based on the projected amount of excess available capacity. The primary actions within the various steps are outlined in the chart and table below.

Another important component of MISO's efforts to maintain reliability are partnerships with neighboring systems. Throughout the Arctic Event, MISO was working hard to ensure reliability not only on its own system, but also to support the efforts of neighboring systems, especially in the Southwest Power Pool (SPP) area. At one point during the Arctic Event, PJM pushed as much as 13,000 MWs into MISO's system, which MISO and SPP used to maintain economic pricing and support grid operations. Notably, high flows strained MISO's transmission system on multiple occasions during the event, contributing to the need for emergency declarations and some of the emergency load reductions.

Normal Operating Procedures

Guide various situations that occur in the day-to-day operation of the bulk electric system.

Abnormal Operating Procedures

Utilized for events that deviate from normal but do not put the electric system at risk, such as malfunctioning software or telephone systems.

Conservative Operating Procedures

A subset of Normal Operating Procedures designed to prepare local operating personnel for a potential event and to prevent a situation or event from deteriorating. Examples include forecasts anticipating severe weather, hot/cold weather, or geo-magnetic disturbance warning.

Emergency Operating Procedures

Emergency Operating Procedures guide system operator actions when an event occurs on the electric system that has the potential to, or actually does, negatively impact system reliability. Examples include Market Capacity Emergencies and Transmission System Emergencies.

Summary of Market Capacity Emergency Operating Procedures

Event Status	Actions
CAPACITY ADVISORY: *Energy shortage is forecast*	Update stakeholder market data
ALERT: *Electricity supply is tight and may require emergency resources*	Maximum generation (Max Gen) declaration; defer maintenance; prepare for event
WARNING: *Conditions are tightening and may not meet requirements*	Schedule all resources; limit exports; implement emergency pricing
EVENT STEP 1: *Requirements cannot be met through normal operating limits*	Max Gen event; utilize emergency-only units and emergency pricing
EVENT STEP 2: *Requirements cannot be met through emergency resources*	Load Modifying Resources; external purchases; public appeals
EVENT STEP 3: *Operating reserves depleted*	Utilize supplemental reserves
EVENT STEP 4: *All available MISO resources utilized*	External emergency energy purchases
EVENT STEP 5: *Requirements cannot be met*	Coordinated load interruptions

Timeline of Key Arctic Weather Events

February 9-14, 2021

For this event, whose most significant impacts spanned February 14-17, preparations began much sooner. As MISO monitored the developing weather situation and gained increasing clarity about the timing and magnitude of cold temperatures, various operating procedures were implemented beginning on February 9, with the issuance of a Cold Weather Alert effective for February 13-15. MISO then issued Informational Advisories on February 10 and 11 to raise awareness of the importance for members to update MISO with accurate generation/resource offers reflecting projected fuel supply access or availability. These advisories also requested members implement any winterization processes or maintenance for generation resources in the footprint, as well as confirm fuel supply availability through the President's Day holiday[2]. Also, on February 11, as the expectation for the duration of extreme cold expanded, the Cold Weather Alert was extended through February 16.

On February 13 the impacts of the upcoming cold temperatures on the South Region pushed load forecasts higher, resulting in MISO committing all generators in the region that require long lead time and issued a Capacity Advisory for the South to raise awareness to the anticipated capacity challenges. With load forecasts still increasing on February 14, weather conditions becoming more severe, and generator fuel risks growing, MISO issued a Maximum Generation Emergency Alert for the South Region effective for February 15.

February 15, 2021 (all times Eastern Standard Time)

In the early morning hours of February 15, snow and ice moved through the South Region causing significant damage to transmission and some generation in the Western load pocket of the West of the Atchafalaya Basin (WOTAB) in eastern Texas.

At 02:34, the China–Stowell 230 kV transmission line, located in southwest Louisiana, tripped off-line. This is significant because it serves as a major corridor for power transfer into Western load pocket. At 03:20, the China–Height 230 kV line also tripped. The loss of these two lines impacted MISO's ability to move power into the area but did not yet necessitate emergency load reduction. The power transfers continued in the east-to-west direction as eastern areas were trying to support the delivery of power to the west.

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[2] Since natural gas markets do not operate on weekends or holidays, there was added complication because forward commitments were being made earlier for less certain forecasts farther in the future. Resources were lining up natural gas fuel based on Thursday forecasts of anticipated needs for Tuesday.

Summary of February 15 Arctic Weather Event Activities
Texas • 02:34 – China-Stonewell 230 kV transmission line tripped • 03:20 – China-Heights 230 kV transmission line tripped • 04:25-4:50 – Two generators tripped offline • 05:40 – Local Transmission Emergency declared • 05:55 – 500 MW emergency load reduction (Entergy) • 06:33 – 300 MW emergency load reduction (Entergy) • 11:48 – China-Height 230 kV line returned to service • 15:12 – 100 MW load reduction released • 16:19 – 200 MW load reduction released • 19:51 – China-Stonewell 230 kV line returned to service • 22:00 – 100 MW load reduction released • 22:46 – 100 MW load reduction released

Between 04:25 and 04:50, two generating units tripped off-line, which increased the east-to-west flows observed on the system.

Due to these unplanned generation and transmission outages, which impacted a main power transfer corridor into Southeast Texas, MISO declared a Local Transmission Emergency for the Western load pocket at 05:40. The transmission outages increased the electricity flows on other transmission lines in that area, creating the potential of overloading the lines and creating instability in the Western load pocket. Ultimately, this loss of generation and transmission led to a localized emergency load reduction event affecting Entergy Texas customers in the Western load pocket, when at 05:55, MISO instructed Entergy to shed 500 MW in the Western load pocket. With demand increasing during the morning load ramp and putting even more strain on the transmission system, at 06:33, MISO instructed Entergy to shed an additional 300 MW (for a total of 800 MW) in the Western load pocket to maintain transmission system security.

During and after the restoration of the transmission facilities, emergency load reduction orders were gradually released based on system conditions. At 11:48, the China–Height 230 kV line returned to service. At 19:51, the China – Stowell 230 kV line returned to service.

Between 15:12 on February 15 and 01:33 on February 16, MISO instructed 700 MW to be restored in the Western Load Pocket.[3]

February 16, 2021

As extreme weather conditions persisted into February 16, operational challenges during the morning's load peak resulted in Maximum Generation declarations for all regions, and emergency load reduction orders in both the South and Central Regions.

[3] The final 100 MW was restored at 13:11 on February 16, and the Local Transmission Emergency declaration was ended at 09:40 on February 17.

By 03:30, two generating units went on forced outage. At 05:30, with the previous day's Local Transmission Emergency still in effect, unexpected generator outages and transmission challenges drove grid stability concerns and the need to direct 300 MW of emergency load reduction in the Southeast Texas area. Additional generation outages occurring at 06:35 exacerbated the already high east to west flows on the system. At 07:00, a Transmission System Emergency was declared in North-Central Louisiana to attempt to keep flows under certain transmission line limits. However, the actions were not sufficient to stabilize the system and at 07:05 MISO instructed 500 MW pro-rata emergency load reduction in North-Central Louisiana from MISO's South Region Transmission Operators. At 07:31, an additional 500 MW of emergency load reduction was requested in that same area.

Separately, at 07:00, a Transmission System Emergency was declared in South-Central Illinois in response to concerns about transmission limit violations due to excessive east to west flows (power flowing from east, through MISO's system to SPP and Texas). This resulted in a "stranded capacity" scenario

Summary of February 16 Arctic Weather Event Activities

Texas
- 01:11 – 100 MW load reduction released
- 01:33 – 100 MW load reduction released
- 03:30 – Two generating units forced offline
- 05:30 – Generator trips offline
- 05:30 – 300 MW emergency load reduction (Entergy)
- 06:35 – Generator outages
- 09:33-11:10 – 300 MW load reduction released
- 13:11 – The final 100 MW load reduction released; Entergy advised that not all load may be restored due to system damage

Louisiana
- 07:00 – Transmission System Emergency due to large transmission flows on Webre-Wells 500 kV transmission corridor, risk of cascading outages
- 07:05 – 500 MW emergency load reduction from Local Balancing Authorities to mitigate Webre-Wells 500 kV line issues
- 07:31 – Additional 500 MW emergency load reduction from Local Balancing Authorities
- 08:42-11:10 – All load reduction released (incrementally)
- 11:41 – Transmission System Emergency terminated

Illinois
- 07:00 – Transmission System Emergency due to overload of Coffeen-Roxford 345 kV line, risk of cascading outages
- 07:30 – Emergency Energy Alert, all resources committed, concerns about sustaining required contingency reserves
- 07:52 – 130 MW emergency load reduction (Ameren) to relieve system operating limits caused by excess east-west flows
- 13:13 – 130 MW load reduction released
- 14:00 – Transmission System Emergency terminated

System-Wide
- 18:35 – Due to generation losses and fuel unavailability, MISO declares Event Step 2c, commitment of Emergency Demand Response resources
- 18:50 – MISO requested to increase the North-South Regional Directional Transfer Limit from 3000MW to 3700 MW; the request was denied due to neighboring system conditions
- 19:40 – Maximum Generation Event Step 5 declared, 700 MW emergency load reduction across South regional Local Balancing Authorities
- 22:00 – Maximum Generation Event Step 5 terminated

where adequate electricity was available, but it could not be moved to where it was needed due to transmission line limitations. The Transmission System Emergency that was called for Coffeen-Roxford 345 kV contingency resulted in all generation in MISO market east of Illinois becoming unavailable. This large loss of capacity availability took MISO North and Central Regions into an EEA 1 and Max Gen Event. At 07:52, MISO directed Ameren to shed 130 MW in South-Central Illinois to relieve electricity flows exceeding the system operating limits.

At 07:30, MISO declared an Emergency Energy Alert (EEA) 1 and Maximum Generation Event 1b in MISO North and Central Regions, instructing generators to start off-line resources, as all available generation resources are committed and there is concern about sustaining the required contingency reserves.

Load in the South Region started to decrease after the morning peak, and the situation improved. MISO thus released the 1000 MW of the pro rata emergency load reduction in North-Central Louisiana and the 300 MW emergency load reduction in Southeast Texas:

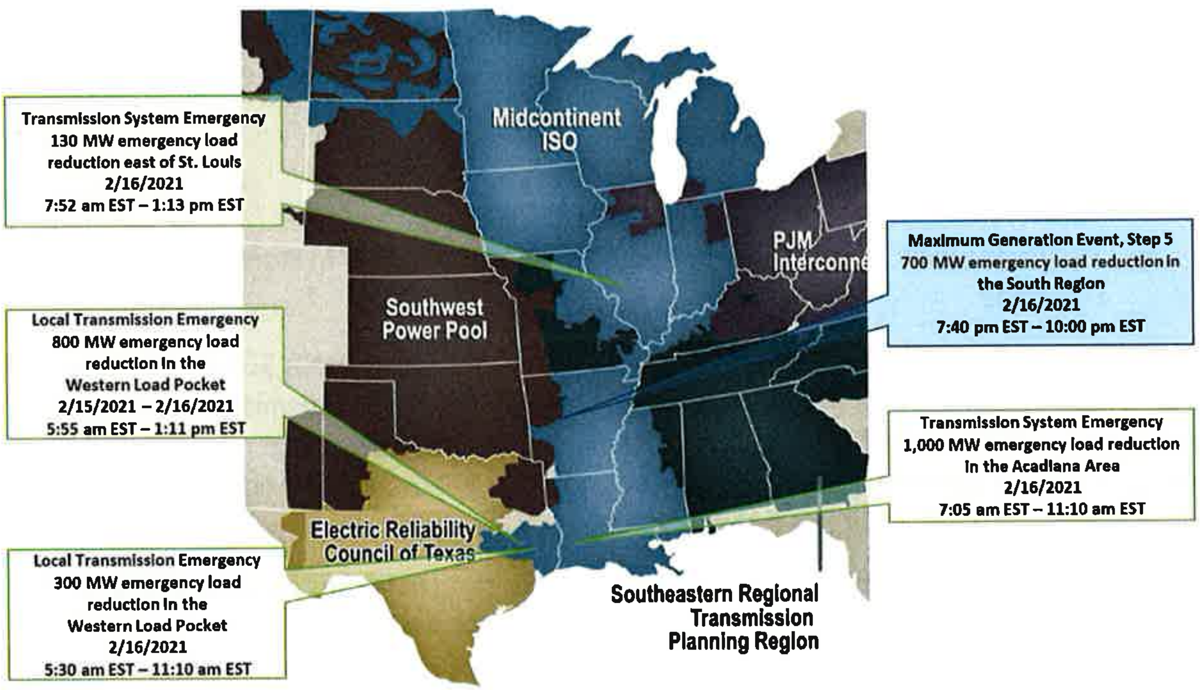
- 08:42: released 400 MW in North-Central Louisiana
- 09:33: released 150 MW in Southeast Texas
- 10:19: released 200 MW in North-Central Louisiana
- 11:10: released 150 MW in Southeast Texas and 400 MW in North-Central Louisiana

By 11:41, all emergency load reduction due to flows on Webre–Wells 500 kV line was restored in North-Central Louisiana, and MISO terminated the Transmission System Emergency. At 13:11, MISO released the remaining 100 MW of emergency load reduction requested from Entergy in Southeast Texas, and Entergy advised that not all load may be restored due to damage on the system.

At 13:13, Ameren restored 130 MW of load that was shed in Illinois because of the Transmission System Emergency, which MISO terminated at 14:00.

However, during the evening increase in electricity demand, multiple generators tripped offline in MISO's South Region, resulting in MISO declaring a Maximum Generation Event Step 2c (EEA-2) at 18:35, which allowed MISO to commit Emergency Demand Response resources when energy requirements cannot be met through normal and emergency-only generating resources. Public appeals for energy conservation were issued at the same time. A short time later, at 18:50, MISO sent a request to neighboring entities for the North-South Regional Directional Transfer Limit to be increased from 3,000 MW to 3,700 MW in an effort to transfer more energy to MISO's South region to compensation for the increased evening demand and offline generators. Unfortunately, the request could not be accommodated due to overloads in Joint Parties' neighboring systems, as TVA already had multiple constraints in excess of 100%.

Realizing the grid's stability was in danger and being unable to import the needed energy to meet demand, at 19:40, MISO declared a Maximum Generation Event Step 5 (EEA-3) for the MISO South Region with instructions for a 700 MW pro-rata emergency load reduction across MISO South Local Balancing Authorities. Utilities in Arkansas, Mississippi, Texas, and Louisiana were each given their pro-rata share of load to shed from their systems. The entities then determined which customers would be impacted. The entire emergency load reduction event lasted two hours and twenty minutes, terminating at 22:00 as load decreased and MISO released all emergency load reduction for restoration.

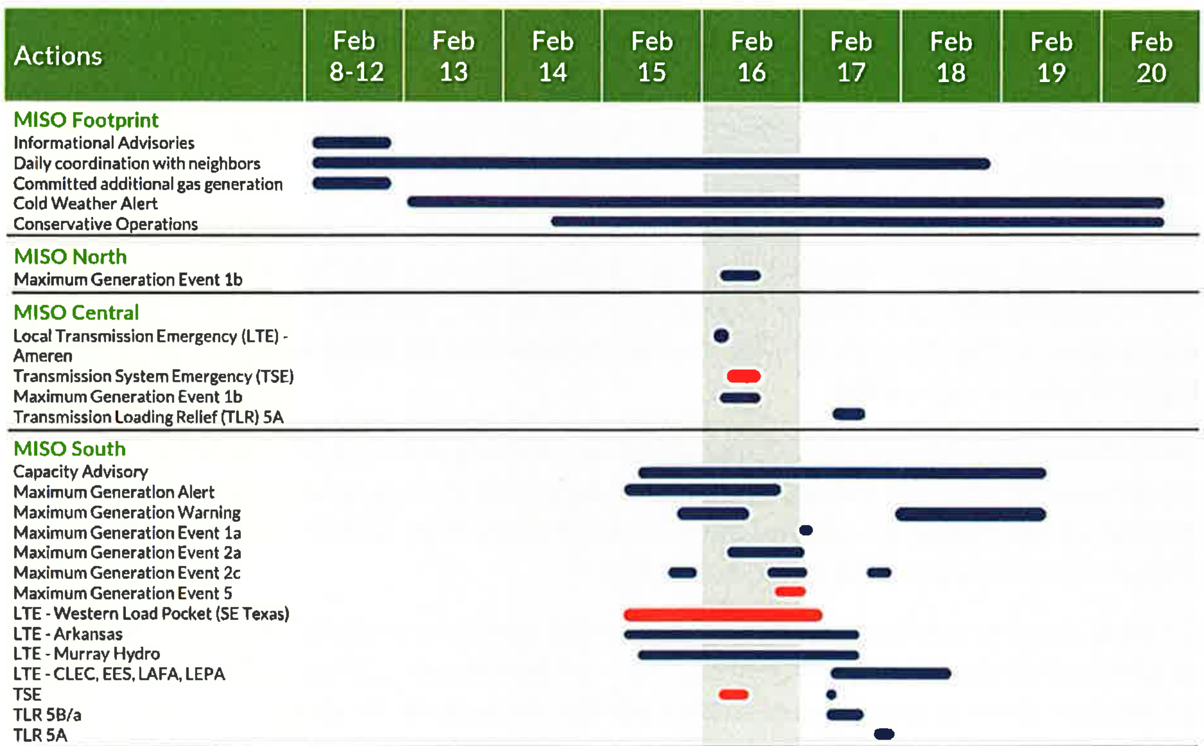


Note: time frames represent the duration from when emergency load reduction was ordered through release of the full amount of load

During an EEA-3 event, per the MISO Tariff, prices in the affected area increased to the established Value of Lost Load (VOLL), $3,500/MWh. This value is an estimate of the cost of service interruption to customers and is paid to both supply that increases output and to demand response load that is lowered.

Although there were no further emergency load reduction events in MISO's footprint after February 16, 2021, the Arctic Event officially ended when the last alert was terminated on February 20. The following graphic shows the major actions taken in MISO's footprint from February 8-20, 2021.

While control room operators were managing generation and transmission issues, other MISO staff worked with local authorities to help get fuel supply to the plants. Those activities included having conversations with local officials about the importance of power plants. These conversations helped facilitate the prioritization of plows to clear roadways for fuel delivery and ensure plants could operate.



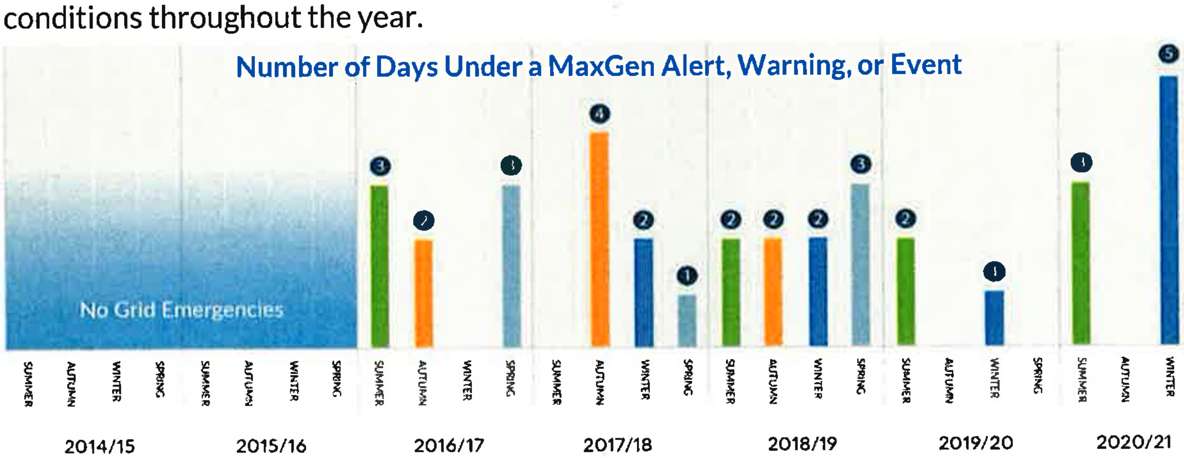
Review of MISO Processes Supporting Grid Reliability, with Lessons Learned and Action Items

The February 2021 Arctic Cold Weather event provides a real-life case study of the challenges MISO faces in ensuring electric reliability at the lowest feasible cost every hour of every day, even under the most demanding conditions. During this weather event MISO's control room had to manage high levels of generator and transmission line outages across the region, compounded by overloaded transmission lines, high demand for energy, and similar conditions in neighboring regions. Because of MISO's extensive transmission system, diverse resource mix, preparation, and procedures, we were able to limit the impact to a two-hour regional emergency load reduction and several local events. At the same time, the MISO region is likely to see more events in the future that strain system reliability.

Meeting the Reliability Imperative to ensure the future reliability of the grid, requires much more than merely effective operational management of the bulk electric system. It is the outcome of ongoing analysis, process improvement, planning, and preparation that has been occurring throughout MISO's existence and will continue as long as electricity is important to our way of life.

Over the last several years MISO has observed concurrent trends of increasing occurrences of extreme weather conditions that strain the system and an evolving generation portfolio with a higher percentage of renewables that increases the complexity of managing the bulk electric grid.

Emphasizing the coming challenges, after several years of no emergency declarations, beginning in the summer of 2016 MISO has seen an increase in the need for maximum generation alerts, warnings, or events to manage through challenging operating conditions throughout the year.



It is clear that the approaches that served the region very well for many years must be adapted to the changing landscape. As a result, in recent years MISO stepped-up efforts to better understand the potential impacts of the evolving resource portfolio, changing supply, demand, and risk profiles, and system changes required to mitigate the various risks and demands.

The Renewable Integration Impact Assessment (RIIA) was a 4-year analysis conducted by MISO to understand the complexities of integrating renewable resources, which are intermittent in their energy generation capabilities, at varying penetrations in the interconnected electric system in the eastern United States, with a focus on the MISO system. The analysis found that as renewable energy penetration continues growing, up to about 30% penetration, the region requires transmission expansion and significant changes with current operating, market, and planning practices. However, managing the system when load being served from renewable resources exceeds 30% will require transformational changes in planning, markets, and operations, and coordination action with MISO members.

The annual MISO Forward report looks ahead to anticipate and understand the trends and changes in the energy landscape that shape the future of our industry. The latest MISO Forward report examines the changing nature of energy demand, as our nation trends toward decarbonization and increasing electrification. Past reports have explored the future needs of electric utilities as the resource mix transforms and the evolution toward demarginalization, decentralization, and digitalization that is changing the energy paradigm.

The following sections of this report cover topical areas with a more detailed description of MISO's response to the Arctic Event including lessons learned, and MISO's actions to address those lessons learned.

MISO has organized the topical discussions into groupings – first to cover the time periods leading up to and during the event, followed by a discussion of financial impacts and communication before, during, and after the event:

- System Planning, including both transmission and markets
- Preparation, including seasonal and event preparation and weather forecasting in the days and weeks before the event
- Operations, including Emergency Load Reduction and Regional Directional Transfer, Pricing, and Staffing and Tools
- Credit / Collateral
- Communication

Note, this report describes MISO's lessons learned (which are also compiled in the Appendix) – some of the follow-on actions are under MISO's direct control, and those actions may be planned to occur in the very near term or they may be scheduled over the coming years as MISO seeks changes to the Tariff or wait for additional infrastructure. These actions may evolve over time as MISO continues to learn and to hear more from stakeholders. Moreover, this report also describes lessons learned that will require actions from our stakeholders and MISO stands ready to consult or help them complete those actions. There may also be additional lessons or actions that are entirely housed without stakeholder organizations and not covered in this report. MISO is committed to working collaboratively with its members, regulators, and other stakeholders to address key takeaways. We invite all stakeholders to review and discuss these takeaways at the upcoming workshop and throughout the coming months.

System Planning

MISO engages in a number of efforts to better position the grid for future challenges. The electricity system is in a constant state of change shaped by existing generation and emerging technologies like battery storage and solar power. Retirements, aging thermal units, and the addition of intermittent wind and solar resources dramatically change the characteristics of the MISO resource fleet. While grid operators have managed variability and uncertainty in the system for decades, MISO expects this variability and uncertainty to become more profound, making it more challenging to manage supply, load, and reserves.

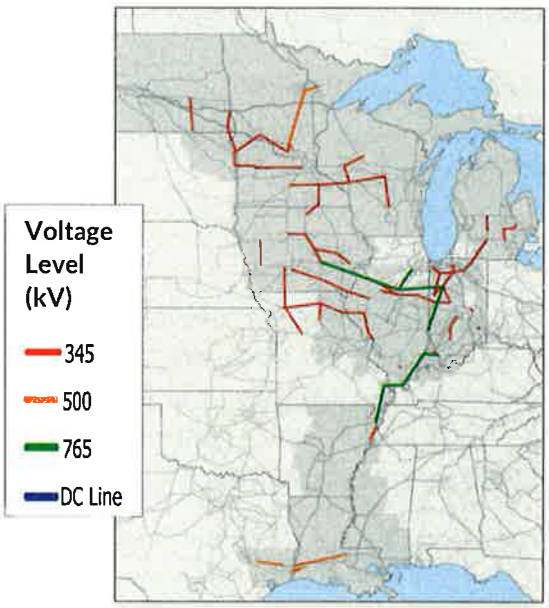
Transmission Planning

The goal of System Planning at MISO is to develop a comprehensive transmission system expansion plan that meets reliability needs, policy needs, and economic needs. Recent extreme weather events such as the Arctic Event have emphasized the importance of planning a robust, resilient transmission system, as the MISO system was able to move large amounts of power across the MISO grid from north to south, and to import power from the east for use by MISO and SPP.

MISO uses future scenarios, also called "Futures," in its planning processes. Rather than trying to pinpoint an exact mix of conditions into the future, these scenarios seek to span a broad range of potential resource and load scenarios and develop a grid that can meet a wide range of plausible conditions over twenty years into the future. Research and analysis into the evolution of the MISO system has identified six key components of system change that are reflected in the scenarios: Traditional Resource Retirements, Renewable Energy Growth, Increasing Energy Storage, Distributed Energy Resource Adoption, Electrification, and Decarbonization.

Long-Range Transmission Planning (LRTP), one of the four main components of the Reliability Imperative, is the process whereby MISO is leveraging the Futures to identify and inform short-term and long-term solutions to enable the resource portfolio shift. The conditions for successful planning include a consensus that transmission is required to address sub-regional and collective needs, a deeper analysis of those issues and solutions and ensuring allocation of cost that is roughly commensurate with benefits to each area.

The two maps below represent MISO's first pass at what the LRTP additions could be for Future 1 and Future 3. These are preliminary plans and will be refined through further analysis and discussion with stakeholders.



Future 1

Future 3

Planning can help to address the issue of having sufficient ability to move power within MISO and between different regions. MISO reciprocally provides and receives power from its neighbors. At one point during the Arctic Event, PJM, MISO's eastern neighbor, was exporting 13,000 MW into MISO. Transmission lines are just as critical across MISO's footprint boundaries as they are within MISO's service area. The future resource portfolio will require additional transmission to maintain the strength of connection in a world with increasing intermittent resources.

Lesson Learned: While MISO's robust grid, along with its ability to import power from outside of the region, resulted in relatively limited impacts during the Arctic Event, MISO needs to continue evolving its transmission system in response to the changing resource mix and evolving grid. The anticipated changes in resource mix and extreme weather puts increased urgency on transmission planning.

Actions to address:

- *MISO will leverage the Long Range Transmission Planning (LRTP) activities to identify intra- and inter-regional planning to ensure reliability as the resource mix continues to evolve and disruptive weather events become more frequent. In particular, LRTP will evaluate further north-south transfer capability which would have helped during the Arctic Event.*
- *Transfer capability - MISO will examine load pockets as part of transmission planning and resource accreditation.*
- *Along with LRTP, MISO will also continue to work with all of its seams partners to identify ways to increase coordination. For example, MISO and SPP are currently engaged in an effort focused on the SPP – MISO seam.*

Resource Adequacy

In the MISO Region, customer-facing utilities are responsible for making sure they can meet customers' electricity needs. MISO supports this responsibility by setting resource planning requirements such as planning reserve margins and resource accreditation standards, and by providing secure and reliable ways for utilities to buy or sell capacity. MISO aims to maintain confidence in the attainability of resource adequacy at all times.

Resources planning processes focus on mitigating resource adequacy risk during tight operating conditions. Historically, system risk has been concentrated in the summer season and typically associated with summer season system peak load. Accreditation of resources (or how much a unit counts towards capacity requirements) has also focused on resource availability during summer peak conditions. Increasingly, risk is spread throughout the year and a resource's winter capabilities may differ significantly from its summer capabilities. Additionally, outages during severe conditions like the Arctic Event currently have only modest impacts on accredited value and some outages have no impact (e.g., planned outages and outages outside of management control). The Resource Availability and Need (RAN) program, part of the Market Redefinition component of the Reliability Imperative, is evaluating seasonal risks to resource adequacy, informed in part by the 2015 Polar Vortex. Risks identified during that event have led to MISO to focus on creating a seasonal resource adequacy and accreditation construct.

Lesson Learned: MISO's resource adequacy construct provided transparency about adequacy of resources to meet projected summer loads. However, improvements can be made to more fully account for the non-summer risks and to ensure that resources will be available across all seasons. MISO has already seen and anticipates continued reliability challenges throughout the year – while reliability risk was once concentrated in the summer season, MISO now has to be increasingly concerned with every hour of the year.

Action to address:

- *MISO is moving to a sub-annual (4 season) resource adequacy construct and an accrediting methodology based in part on a resources' availability during the hours when the system is most in need (tight operating hours), thereby giving resource owners an incentive to ensure resources availability through investments in winterization, fuel assurance or other means. These changes are expected to be filed at the Federal Energy Regulatory Commission (FERC) in the second half of 2021.*

Lesson Learned: Current resource accreditation criteria do not specifically address generator readiness to operate during extreme weather events. With the rapid fleet transition toward natural gas and the increased frequency and severity of extreme weather, this issue is expected to worsen over time.

Actions to address:

- *MISO will work with states and others to identify changes that may be required in MISO processes or elsewhere, to better reflect resource availability during extreme weather events (e.g., winterization needs during extreme cold, fuel assurance).*
- *MISO will consider the impacts of the generation fleet change on the need for additional coordination with the natural gas sector on issues of fuel assurance.*

Market prices provide further incentives for resources to provide energy in the actual operating day. Price formation during shortage conditions is addressed further below and is also part of the Reliability Imperative component of Market Redefinition.

Preparation

Seasonal Preparation

Since 2014 MISO has conducted a Winter Readiness Workshop that brings together stakeholders to review winter lessons learned, winter operations guidelines, preparedness, resource assessments, and readiness.[4] Below we walk through the different components that are reviewed during the Workshop, including Winterization Guidelines, Seasonal Resource Assessments, Seasonal Transmission Assessments, and Generator Winterization Annual Gas Fuel Survey, and Drills.

Extreme winter conditions can contribute to significant losses of electric generation through a variety of factors. Cold temperatures can freeze equipment for various types of electric generators. Frozen transportation equipment and facilities can prevent generators from obtaining fuel. MISO provides Winterization Guidelines to help members mitigate the effects of winter weather risk. These guidelines, which benefitted MISO's region during the February 2021 Arctic Event, are the results of lessons MISO learned from the 2014 Polar Vortex event when approximately 25,000 MW/day of capacity (not including plants whose output was reduced due to weather), was forced offline due to weather-related outages.

MISO directs power plant operators to create a detailed winterization plan that covers preparations and procedures to complete ahead of frigid weather conditions.

In addition, MISO market participants are responsible for ensuring fuel availability and deliverability to their generators.

NERC also has reliability guidelines related to winter readiness. MISO advises generator operators to follow NERC's Winter Generator Reliability Guidelines when preparing for and operating in severe cold weather conditions. MISO advises generator operators to follow NERC's most recent guidelines. MISO is also actively engaged in the process to develop NERC Cold Weather standards along with other initiatives such as FERC's Climate Change, Extreme Weather & Electric System Reliability Technical Conference, to support the development of policies that will collectively address the increased risks seen during the Arctic Event.

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[4] Note, that summer weather presents similar but distinct challenges such as severe weather patterns, forced outages, transmission congestion, seasonal maintenance, and higher than average load. MISO specifically prepares for hurricane season in a week-long training. MISO also conducts a Summer Readiness workshop at which MISO discusses its summer generation and transmission assessments, reviews applicable operating procedures, and communicates processes during abnormal and emergency conditions, as well as presents other topics related to seasonal operations. Additional information is available on MISO's website.

MISO also conducts two coordinated seasonal assessments. The **seasonal resource assessment** is done in all four seasons to evaluate MISO's available resources and perform risk assessments. Two scenarios are explored during the seasonal resource assessment – the first is a more general scenario with average levels of demand and resource outages. The second case is a more extreme scenario, with a high load level and a worst-case volume of resource outages (based on five-year historical outage information provided by resource owners and typically due to abnormal weather conditions). In this more extreme scenario, MISO explores the need to use emergency procedures and allows operators to practice monitoring load modifying resources and emergency load reduction.

Lesson Learned: In reporting results of Seasonal Assessments, MISO and stakeholders have not typically focused as much on the extreme cases (high load + high outages).

Actions to address:

- *MISO will focus more attention on extreme outcomes as well as expected outcomes during seasonal assessment workshops.*
- *MISO will evaluate how to incorporate existing extreme cases into Seasonal Assessments and drills.*

Lesson Learned: Current emergency load reduction plans are focused on summer needs. This new experience provides an opportunity for MISO and stakeholders to assess preparation for winter events.

Actions to address:

- *MISO will investigate the feasibility of a pre-winter feedback loop, which would allow members to express their readiness for the winter weather. This feedback would include information about generator weatherization and winter checklist completion.*
- *MISO will encourage Local Balancing Authorities (LBAs) to refine emergency load reduction plans to include winter event load shedding, when cutting power can have different consequences than in the summer. MISO will encourage the refined emergency load reduction plans to consider which elements are critical and what to do if the requested emergency load reduction exceeds their capacity to rotate outages.*
- *MISO will seek additional feedback from stakeholders on their learnings from past events during the Seasonal Assessment workshops.*

The **seasonal transmission assessment** analyzes and assesses the MISO transmission system under projected load conditions for the seasonal peak. The coordination of this study across the MISO footprint provides the benefit of reviewing the network over a much larger area than would normally be assessed by the individual participating Transmission Owner (TO). During the seasonal transmission assessment, four different analyses and simulations are conducted, including the Steady State AC Contingency Analysis, Thermal Analysis during Energy Transfer Simulations (or First Contingent Incremental Transfer Capability (FCITC)), Voltage Stability Analysis during Energy Transfer Simulations (or Power-Voltage Analysis (PVA)), and the Phase Angle Analysis during Energy Transfer Simulations. Contingency levels and sensitivity cases included in the seasonal transmission assessment are often beyond those typically considered in Real-Time Operations and regional planning criteria. These events have been evaluated to provide system operators with guidance as to possible but unlikely system conditions that would warrant close observation to ensure system security.

Lesson Learned: In extreme events, energy flows may be very different than those seen under normal operations. During the Arctic Event, MISO experienced very high flows across its system, and in an unusual direction as power was flowing from the (relatively warm) east coast to the more impacted central part of the country. With the increased severity of extreme events, it will become more important to plan for these scenarios.

Action to address:

- *MISO will include the impacts of high wheel through flows in the seasonal transmission assessment to better prepare for extreme weather events.*

In addition to the seasonal assessments, MISO also surveys its members using the **Generator Winterization Survey and the Annual Gas Fuel Survey**. The Generator Winterization Survey collects information on all generation while the Annual Gas Fuel Survey only collects information from generators with fuel types of gas, oil and gas, and coal and gas. In 2020, 71% of all generation (in MW) responded to the Generator Winterization Survey, improving from 60% in its first year (2019). In its seventh year, 83% of generation (in MW) responded to the Annual Gas Fuel Survey, up from 72% in 2019. MISO communicated the importance of these surveys through presentations at stakeholder meetings, emails, and phone calls. The information gathered includes statistics on generators with plans to prepare for the winter weather, generators with severe cold weather checklists, and generators that experienced freeze issues in the previous winter season. MISO also gathers information on gas fuel capacities. The survey information gathered for this past winter helped to inform operators during the Arctic Event as they dispatched generation.

Lesson Learned: Based on experience during the Arctic Event and the significant number of generator outages based on cold weather conditions, MISO believes that additional data, provided by additional survey participation, will help to inform decisions made during future extreme weather events.

Actions to address:

- *MISO is combining the Winterization and Annual Gas Fuel surveys and removing all backward-looking and redundant questions, with the goal of increasing participation in the survey. MISO will consider additional ways of accessing this information, including engaging in the process to develop NERC Cold Weather standards to be reflective of the increased risks seen during the Arctic Event.*
- *Incorporate fuel assurance into scenario planning and drills, with a particular focus on MISO visibility into fuel plans.*

To ensure readiness in all situations, MISO's operators partner with operators at member companies to run **drills** on the use of use emergency procedures and processes. Emergency Operating Procedures[5] guide operator actions when an event has the potential to negatively impact the Bulk Electric System. The procedures allow MISO and regional operators to defer or cancel transmission or generation outages to increase transfer capability and capacity. These procedures also provide instructions for returning planned outages/maintenance equipment to service in impacted areas, suspend all work on critical computer systems, and prepare for the implementation of Emergency Procedures.

Lesson Learned: Drills have been helpful in coordinating among operations staff. Given the wide scope of the Arctic Event, the drills were not sufficiently comprehensive. In recent years, MISO has shifted to more tabletop exercises with specific groups (e.g., outage coordination or cyber security). However, the Arctic Event and the expected growth in similar extreme weather events in the future points to the need for comprehensive drills that include more groups across MISO and member utilities.

[5] These procedures include Conservative System Operations, Severe Weather Alerts, Hot Weather Alerts, Cold Weather Alerts, and Geo-Magnetic Disturbance Warnings.

Action to address:

- *Increase comprehensive drills for extreme events – including operations, outage coordination, emergency load reduction planning, communications, and regulatory coordination. MISO plans to incorporate more fuel assurance scenarios and responses into planning and drilling.*

Event Preparation

Once a specific event is identified, there is additional preparation that MISO undertakes, often in coordination with its members, to prepare the system in the days directly leading up to the expected event.

MISO has many established processes and tasks to prepare for events, including some regular processes that are updated more frequently when the risk of extreme weather is changing rapidly.

- MISO conducts a Forward Reliability Assessment Commitment (FRAC) study on a regular basis, running cases based on submitted offers and delivering a six-day-ahead forecast. This normal process highlights upcoming risks, where extreme weather, including extreme temperatures, increase the chance of shortages. MISO addresses those risks with forecasting and risk assessment. During normal operations, MISO's forecasting team monitors and presents the current forecast data displayed on the Operational Forecast Dashboard. This data includes 168-hour weather and load forecasts at an hourly interval for MISO Systemwide and regionally. Graphical displays illustrate the high and low temperatures and hourly load forecasts over the next seven days. This dashboard and the accompanying data are presented every weekday to inform MISO Operations staff of the weather/load forecasts and to highlight any significant values and risks for situational awareness. The FRAC study process and Operational Forecast Dashboard have proven helpful in understanding the impacts of the weather conditions, including icing and extreme temperatures on renewable resources and operating gas resources in extreme cold.
- Additionally, MISO assesses the risk to the Net Schedule Interchange (NSI), or the flows between MISO and its neighbors. Particularly when a weather event is expected, MISO works closely with and monitors its neighbors (e.g., PJM, SPP, TVA.) to ensure that MISO is able to accurately forecast NSI leading up to the event. As a part of event preparation, MISO assesses which resources may trip offline or fail to start up in extreme weather. This risk assessment allows MISO to make decisions about starting resources with longer lead times or extending commitments for resources that may not be able to restart during an event.

- The week before the Arctic Event, MISO started discussing outage coordination with members, ensuring they had fuel and understanding what impacts a lack of fuel would have.[6] MISO's forecasting teams provided updates on the latest weather and load forecasts for the upcoming week to the Operations Department. MISO staff communicated the likely risks associated with the weather. Beginning February 9, 2021, and for the remainder of the Arctic Event MISO management received more detailed daily weather forecast briefings.
- In addition to frequent communication with MISO operators, MISO also sent many messages that reference the upcoming cold weather conditions that faced the MISO Balancing Authority. There were several informational messages sent in the MISO Communication System (MCS) which requested MISO members update their availability, keep their Day Ahead and Real Time offers updated, and prepare for the upcoming cold weather. Additionally, in accordance with the Conservative System Operations Procedure (SO-P-NOP-00-449), MISO declared a Cold Weather Alert and Conservative System Operations throughout the event.[7]

Lesson Learned: MISO's ability to accurately forecast weather conditions directly leading up to and during the Arctic Event, facilitated by having a meteorologist on staff, gave MISO the opportunity to prepare in advance, including issuing Informational Advisories early in the week prior to the event, reminding members to accurately reflect projected fuel supply access and availability to their generation and resource offers. These advisories also requested members implement any winterization processes and maintenance for generation resources in the footprint and confirm fuel supply availability through the President's Day holiday.

Action to address:

- ➢ *MISO will continue to leverage in-house and vendor meteorology expertise to inform MISO operational decisions and communication with members. MISO is continuing to assess how best to translate accurate weather forecasts into accurate forecasts of the effects of the weather (e.g., outages tied to weather).*

[6] The extreme cold caused icing on the wind turbines in MISO's footprint. However, output from wind generation was low throughout the duration of the event and the icing did not have a major impact to generation overall.
[7] These declarations were made at various times, and the entry conditions for each are specified within the public procedure.

Lesson Learned: MISO's current process to identify available uncommitted resources is tedious, takes more time than necessary, and does not always leave sufficient time to start resources with a long lead time. The spreadsheet-based tool currently used to identify resources must be operated manually each time it is needed, taking upwards of five minutes to compile necessary information.

Action to address:

- *In order to provide more visibility into available units, MISO is preparing an Available Resource report as part of the Capacity Sufficiency Analysis Tool (CSAT) to communicate to MISO commitment teams the resources available for commitment. The report provides a list of resources available for capacity at any given point in time and helps operations make commitment decisions during tight operating conditions by producing a dynamic list of resources, meaning that a resource will automatically drop off the available commitment list if its window for start-up has passed for any given hour.*

In summary, MISO took the following steps leading up to the Arctic Event:

- Issued Informational Advisories reminding members to accurately reflect projected fuel supply access and availability in their generation/resource offers;
- Issued a Cold Weather Alert to prepare operating personnel and facilities for extremely cold weather conditions that may impact generation and/or transmission capacity;
- Committed additional generation with lead time enabling members to procure fuel;
- Extended the start/stop times for generation resources to avoid start failures due to cold weather thus ensuring availability during peak load times;
- Confirmed planned outage and return-to-service dates/times for generation and transmission outages;
- Continued communication and coordination with members requesting updated resource availability and offers;
- Proactively coordinated with members on maintenance outages which combined with limited maintenance work by members due to the holiday weekend did not require suspension of maintenance; and
- Coordinated with neighbors as they similarly prepared for this weather event.

Operational Details

Emergency Load Reduction and Regional Dispatch Transfer (RDT)

The challenges faced by MISO's operators during the Arctic Event were driven by a combination of complex factors, including generator outages, transmission outages, and excessive electricity flows on some undamaged transmission lines that exceeded safe operating limits. Throughout the event, MISO relied on its established procedures to operate the system safely and reliability, while mitigating the negative system impacts of the extreme conditions.

As discussed above (see "Grid Impacts and Operation"), MISO utilized its established Emergency Operating Procedures to manage energy flows and ensure system security. These procedures allowed MISO to adjust quickly to system conditions as they unfolded. For example, increased demand due to extreme cold weather coupled with unexpected changes in available electric generation and transmission flows can rapidly affect the balance of supply and demand on the transmission system. Procedures like Maximum Generation emergency procedures, coordination of generation and transmission, energy purchases from neighboring regions, and demand response and load-modifying resources are important tools that allow MISO greater flexibility to ensure system reliability. In the case of the Arctic Event, the extreme conditions required MISO to undertake the rare actions of directing member utilities to issue public appeals for electricity conservation and to shed load to protect the bulk electric system.

At one point during the Arctic Event, PJM pushed as much as 13,000 MWs into MISO's system, which MISO and SPP used to maintain economic pricing and support grid operations. Neighboring entities worked together to manage the issues caused by the Arctic Event, and several entities noted how effective the SPP and MISO coordination efforts were. The flows across MISO's system also contributed to the need for emergency declarations.

The MISO footprint is roughly shaped like an hourglass with the middle being the interconnection between MISO North/Central and MISO South Regions, which you can see in the graphic below. The black arrow in the picture represents the Regional Dispatch Transfer, or RDT. MISO's Transmission Owners have limited transmission facilities to move power through the RDT, so MISO has agreements with neighboring organizations to use their transmission capacity to move power back and forth between MISO North/Central and MISO South. The RDT Limit (RDTL) is a cap on MISO's contractual right to use the Joint Parties'[8] available system transmission capacity and is set at 3,000 MW North-to-South and 2,500 MW South-to-North.

Image represents average flows into, out of and through MISO over 3 days (February 15-17, 2021)
RDT = Regional Dispatch Transfer, which has a North-South limit of 3 GW

Due to extreme temperatures on February 15, 2021, load was increasing across the southern United States. Load in the South Region was approaching summer peak levels, which are typically higher than winter peak load. MISO had committed available resources to meet projected demand. See "Timeline of Key Arctic Weather Events" section, above, for a discussion of event timeline and key happenings. The following section provides details about operational aspects of the Arctic Event and Regional Dispatch Transfer (RDT) issues.

Regional Dispatch Transfer Limit (RDTL) (All times in EST)

The RDTL between MISO's North/Central and South Regions is an important tool for managing reliability and efficiency. However, in many instances, such as the Arctic Event, the 3,000 MW limit hinders operational effectiveness.

[8] Southwest Power Pool (SPP), Tennessee Valley Authority (TVA), and Southeastern Reliability Corporation (SERC).

During the period of February 8, 2021 through February 20, 2021, the MISO Reliability Coordinators[9] had several discussions and exchanged numerous phone calls with adjacent Reliability Coordinators about exceeding and adjusting the Regional Dispatch Transfer Limit (RDTL). Over the course of the Arctic Event RDTL flow was primarily in a North to South (N-S) flow direction close to the 3,000 MW limit. See Figure 1 below.

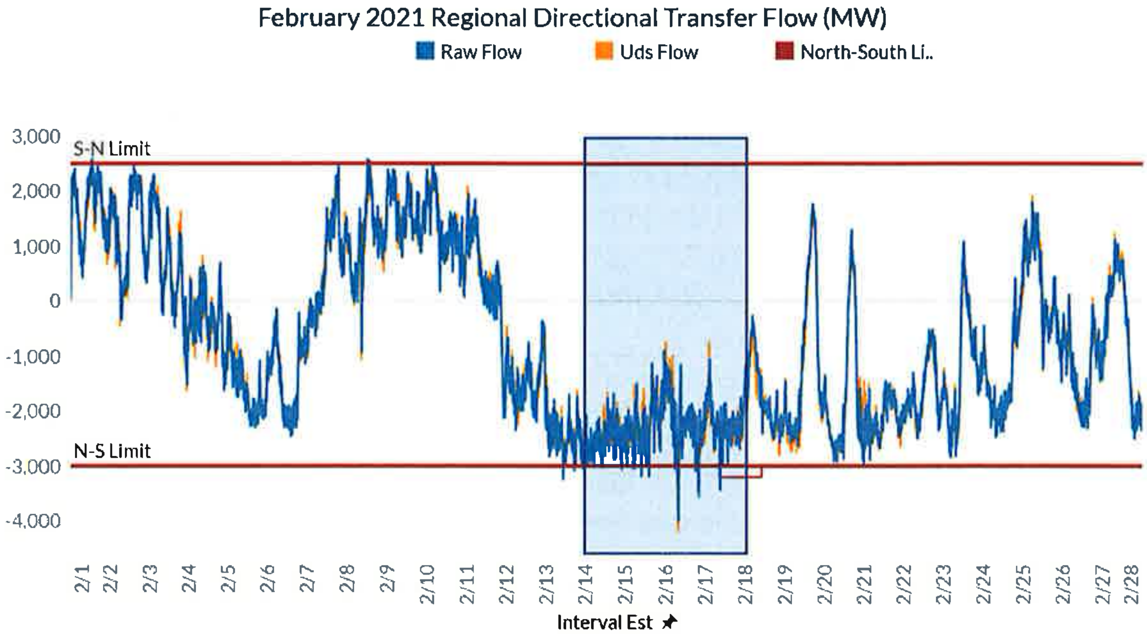


Figure 1: February 2021 Regional Directional Transfer Flow (Note: positive numbers represent South to North flows and negative numbers represent North to South flows)

The first interaction between MISO and the Joint Parties to discuss temporarily increasing the RDTL occurred on February 16 at 17:50, when MISO initiated a conference call in response to the loss of several generation units within a minute. These losses caused the RDTL to exceed the 3,000 MW N-S limit. During this call, SPP and SERC both saw no issues with increasing the limit. However, TVA reported their studies indicated a potential limit exceedance on other equipment if the RDTL was raised. No limit change was enacted and the RDTL flow was brought under the limit within 10 minutes.

The second discussion was on February 16 at 18:50, when MISO requested a limit increase to 3,700 MW. SERC identified they could facilitate an increase to 3,300 MW, but

[9] MISO has multiple roles, including as the region's Reliability Coordinator, a NERC designated role that is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations.

any further increase would force them into a Transmission Loading Relief (TLR), which would cut schedules into MISO. TLR procedures are used in the Eastern Interconnection to prevent or manage potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the bulk electric system. TVA was unable to facilitate an increase due to multiple constraints including already being in a TLR procedure. SPP was studying options but stopped once TVA declared they could not accommodate. Shortly thereafter, TVA entered an EEA 2. No limit increase occurred.

The third interaction was on February 17 at 08:28 when MISO contacted TVA, SPP, and SERC regarding RDT exceeding the N-S limits and requested a limit increase to 3,200 MW. The Joint Parties agreed, and the limit was changed to 3,200 MW. At 08:43 MISO started individually calling the Joint Parties to request an additional RDTL increase to 3,400. SERC refused the increase. On February 18 at 10:00 the RDTL was reset to its normal 3,000 MW limit.

Unplanned Exceedance of the RDTL

From February 13 through February 18, the RDTL in the N-S direction was exceeded in 18 instances. Sixteen of the exceedances were less than 30 minutes, and 15 were 10 minutes or less in duration. There were no RDT exceedances in the S-N direction. Through most of this period, the RDTL in the N-S direction was near 3,000 MW. From February 17 at 08:28 until February 18 at 10:00, the RDT N-S limit was increased to 3,200 MW. This adjustment to the limit addressed one exceedance that occurred while the South Region was in a Transmission System Emergency.

The two remaining exceedances both took place on February 16, the first at 07:00, for 55-minutes, and the other at 19:18, for a 40-minute duration. Prior to the 07:00 exceedance, MISO was in a Maximum Generation Event 2C and the Central and South Regions both experienced transmission line exceedances which required immediate action. The Maximum Generation event, constraint loading, and the approach of the morning peak resulted in the RDT exceedance. Given the circumstances, MISO shed load both in the Central and South Regions to control constraints and RDT that morning. The exceedance in the evening of February 16 was a result of several generation units tripping offline during the afternoon and early evening. These unit trips put MISO in a position where it could not control the regional flow through methods used during normal operations. A combination of unavailable resources and high load resulted in RDT exceeding the limit as the South Region approached peak. The situation was remedied by ordering emergency load reduction. Load was restored shortly after peak conditions passed and RDT was maintained below the limit.

Under stressed system conditions, it is not uncommon for an RDT exceedance to occur due to a generation unit trip or other sudden system fluctuation. Generation reserves are typically available to bring the flow within limits promptly as demonstrated in the short-duration exceedances. Increasing the RDT constraint shadow price (or the indication of the marginal value of more RDT capacity) during emergency conditions would aid MISO in controlling exceedances because it provides a financial incentive to market participants.

One lesson learned from the earlier 2018 Cold Weather was that MISO had an opportunity for more effective communicating with the Joint Parties of RTDL exceedances. While MISO's communication did improve during the Arctic Event, room remains for further improvement.

Lesson Learned: The Regional Dispatch Transfer (RDT) can be more effectively managed during emergency operating conditions.

Actions to address:

- *Since identifying this action item following the 2018 Cold Weather Event, MISO has improved communication with Joint Parties on RTD exceedances. MISO will continue to look for ways to better coordinate with Joint Parties.*
- *When MISO requests a RDT limit increase and one or more of the Joint Parties deny MISO's request, MISO needs a better understanding of Joint Parties' system challenges such as congestion, flows, and outages, and reasons for MISO's request for a limit increase is being denied. MISO plans to address this issue in the current contract renegotiations.*
- *Review schedules at a more granular level and target cuts to those with greater impact to RDT. Develop a tool that MISO operations can use to visualize what is driving impacts to the RDT.*
- *Increase the shadow price for RDT prior to emergency events. Increasing the RDT shadow prices will limit flows and allow more efficient management of the RDT limit.*

Local Transmission Emergency and Maximum Generation Event Level 5 Pricing

Local Transmission Emergencies (LTE) are declared when MISO expects it will not be able to mitigate operating limit conditions using normal procedures in a timely fashion. During the Arctic Event, MISO declared several LTEs. Of note, MISO declared an LTE for the Western Load Pocket on Feb 15-16 because of large generation outages in the pocket and forced transmission outages causing potential overloads. This declaration included shedding firm load.

This section describes lessons learned and actions that combine both the Arctic Event and the 2020 Hurricane events (in particular, Hurricane Laura). While the events differ in season and root cause, they highlighted similar issues with localized emergency load reduction events that had both transmission and generation causes. Some of the actions listed here were identified after Hurricane Laura and are still in the process of being finalized and filed at FERC.

The IMM noted that during Hurricane Laura, MISO declared a capacity emergency for similar issues in the Western Load Pocket but opted for an LTE in the Arctic Event. Locational Marginal Prices (LMPs) and Market Clearing Prices (MCPs) would have required after the fact repricing and set to the Value of Lost Load (VOLL) ($3,500 per MWh) had MISO declared a capacity emergency (EEA 3)rather than the LTE in the Arctic Event. Instead average LMPs were $843 per MWh which did not reflect system conditions and operator's actions.

Outage studies showed that about 2,500 MW of generation would be unavailable by 16:00 on Feb 16. Public appeals for conservation were made. Realizing the grid's stability was in danger and unable to import the needed energy to meet demand, MISO declared a Maximum Generation Event Step 5 (EEA 3). Operators notified the Local Balancing Authorities in the South Region to collectively shed 700 MW of load to avoid widespread cascading outages: Entergy Arkansas – 146 MW, Entergy MS – 57 MW, SMEPA – 41 MW, CLECO – 73 MW, EES – 320 MW, LAFA – 9 MW, LAGN – 43 MW, and LEPA – 4 MW. The Local Balancing Authorities then determined which customers would be impacted. The entire emergency load reduction event lasted two hours and twenty minutes. Per the MISO Tariff, prices in the affected area are increased to the established Value of Lost Load (VOLL), which is $3,500/MWh. Because of a data processing issue some LMPs and MCPs had to be repriced after the fact for the Step 5 emergency load reduction event.

Lesson Learned: The current market design during transmission emergency events may not lead to efficient economic outcomes that support system reliability. Operating procedures and market capabilities need to be aligned, and in some cases enhanced, to result in real time prices that reflect system conditions, producing economic outcomes that support system reliability.

Actions to address:

- *Investigate and evaluate market price efficiency during Emergency Events requiring emergency load reduction below the Local Resource Zone levels in order to produce prices consistent with system conditions.*
- *Investigate and evaluate the allocation of Real-Time Excess Congestion, including Revenue Neutrality Uplift costs, due to scarcity pricing.*
- *Investigate ways to ensure that preliminary prices are representative of settlement prices during Step 5 emergency load reduction events. Implementation of such changes will have to be prioritized in light of MISO's Market System Enhancements acceleration effort.*

Tools and Training

As the independent system operator, MISO has responsibility to maintain electric reliability, which it does by addressing the holistic needs of the system – such as energy, capacity, resource adequacy, and flexibility. The electric system is increasingly fueled by wind and solar, and generation fleet change and extreme weather events such as hurricanes and the Arctic Event are increasing risk across the entire year (not just in the summer). To address these challenges, MISO is pursuing the "Operations of the Future" initiative as part of its Reliability Imperative. This effort is designed to ensure that MISO will have the kinds of skills, processes, and technologies it will need to effectively manage both wholesale and retail connected resources. For example, this initiative will leverage artificial intelligence, machine learning, and advanced analytics among other tools to help future MISO control-room operators effectively forecast, visualize, and manage grid uncertainty. It will also help MISO to better manage maintenance and "pre-position" the grid ahead of system changes such as weather. The Arctic Event and the increased extreme weather during the past year has strengthened MISO's focus on and sense of urgency to develop technological tools to support our operators in decision making.

Lesson Learned: Additional and improved technology tools to support operator decision making will be helpful in future events as the increase in extreme weather and fleet change will continue to present visualization and decision-making challenges.

Actions to Address:

- *Design tools to provide better visualization of the system and its pain points.*

- *Implement more efficient analysis programs to more easily and quickly inform operators of critical information needed to inform decision-making, such as a tool to help MISO understand the drivers of the RDT calculation.*

Lesson Learned: The Arctic Event and the extensive use of collaboration tools presented an opportunity to train newer Operators *without their being in the middle of the event response.*

Action to Address:

- *MISO will continue to leverage collaboration tools to allow newer Operations staff to observe during real-world emergency events.*

Credit and Collateral

The purpose of MISO's Credit Policy (Attachment L to the MISO Tariff) is to protect its members by preventing losses in the market that are passed onto its members. MISO's credit team typically calculates a participant's credit exposures based on the market participants' forecasted financial obligations from market activity, and then requires that amount be covered by financial security or secured credit as allowed under MISO's Tariff.

When a market participant can't satisfy financial obligations, also known as a default, MISO may suspend all services (subject to FERC approval for load serving entities). The defaulting entity's unpaid financial obligation is applied through short payments to the market. A short payment means MISO reduces the revenue distributions for the billing period by the amount of the financial default incurred in the market. Prior to 2021, MISO had no financial defaults of more than $1,000.

Leading into the Arctic Event, MISO's credit team anticipated a risk of significant increase in credit exposures resulting from the potential for emergency pricing being implemented. Because MISO was operating under emergency pricing conditions, there were lags in the settlement credit system for capturing the credit exposure risks from the Arctic Event. The credit team had regular contact with the market reliability and pricing teams to assess the duration and potential impact of the event on market prices.

The Arctic Event caused a significant increase in credit exposure for many market participants. The highest price impact of the event was primarily between February 15 to February 18. However, there was increased pricing and higher demand throughout the week of February 15. Due to the natural delay in forecasting financial obligation and the resulting credit exposure, margin activity didn't spike until the week beginning February

22, resulting in 140 margin calls totaling $325 million[10]. Margin call refers to when a market participant's credit exposure is greater than the financial security and unsecured credit they have in place with MISO, and MISO requests additional collateral or reduced activity in the market. All margin calls were cured by market participants, but some parties indicated a level of financial strain.

Several MISO market participants were concerned that credit calculations used to determine credit exposure would result in margin calls in excess of real financial obligations. There was a concern this could create un unnecessary additional financial strain from the Arctic Event. Market participants mentioned that Southwest Power Pool (SPP) was seeking a specific credit calculation waiver from FERC to suspend margin calls for several weeks post the Arctic Event. Given how the tariff defined credit exposure calculations, MISO did forecast an over collateral position for some market participants in the coming week. Hence, to prevent additional financial strain on some market participants, MISO sought a waiver from FERC on February 24 to allow adjustments to the credit exposure calculation, which FERC approved on February 25, 2021. In the waiver, MISO obtained approval from FERC to use the best available information for the credit exposure calculations. This allowed MISO's credit team to calculate credit exposure using the most current data to better estimate the forecasted financial obligation while not over-collateralizing the market. MISO implemented the changes immediately resulting in over $110 million of margin call relief for 40 market participants.

During this period MISO diligently investigated MISO market participants to identify any that may have been significantly exposed to other markets. The credit team established a target list and investigated each market participant. Fortunately, MISO identified only one market participant with an extreme level of exposure to other markets and that party had already filed bankruptcy.

Combining all high price volatility events including the most recent Arctic Event, MISO is investigating whether potential changes to the Tariff may be beneficial to protect the market.

Lesson Learned: (Bankruptcy and Default Provisions) The specific bankruptcy issue was the first of its kind in the MISO markets because the defaulting party is a load serving entity that did not name MISO as a critical vendor in the bankruptcy. The bankruptcy law puts an automatic stay in place in the action which prohibits MISO from sending certain notices, such as a notice of default, to the party. This creates misalignment with requirements and actions required in the Tariff, including Section 7 of Module A.

[10] For reference, MISO typically issues around 10 margin calls totaling an average of less than $10 million during a week of normal operations.

Action to address:

- *MISO is evaluating if Tariff amendments will help MISO address these types of situations in the future. A potential solution is amending the Tariff to modify the notice process required to parties to resolve the conflicts recently experienced.*

Lesson Learned: (Alternative Credit Exposure Calculations) During the Arctic Event, it became apparent that MISO would over collateralize several members under the Tariff, indicating that MISO needs a modification in the Tariff to account for impacts from extreme pricing events.

Action to address:

- *To better address potential future events, MISO may seek to revise the Tariff and allow for alternative calculations that may be used in extreme pricing volatility events with appropriate notifications to parties. This would be more efficient than requesting an emergency waiver from FERC in the middle of an event; and*
- *MISO is evaluating using the preliminary Locational Marginal Pricing and telemetry data in the credit exposure calculation to cover the expected future S7 settlements. If this approach works, MISO's Credit Policy would need to be revised.*

Lesson Learned: (Minimum Capitalization) The low minimum capitalization requirements in the Tariff may be insufficient in protecting the market in extreme pricing events.

Action to address:

- *Due to increased market price volatility, the minimum capitalization requirements are being evaluated to determine in what instances they provide inadequate protection for the market. Other RTO/ISOs have already made or are considering revisions in this area. MISO is working with the other RTO/ISOs for awareness and potential standardization within the industry.*

Lesson Learned: (Unsecured Credit) Unsecured credit provides a benefit to market participants; however, it also can create unexpected market exposure in extreme pricing events as some market participants may have no cash collateral posted with MISO to offset or cover market defaults.

Action to address:

- *MISO is evaluating approaches that might be used to determine prudent minimum cash equivalent collateral level for market participants, thereby, providing at least some protection to the market in the event of extreme market pricing volatility.*

Communications

MISO communicates to a diverse group, including its members, members' customers, stakeholder groups, seams partners, regulators, legislators, media, and natural gas industry partners. Reaching and informing our various stakeholders effectively and predictably is the driver behind the communication protocols established by MISO's crisis communication plan and operations procedures. Communication is critical during impactful operational events like the Arctic Event. This section of the Report discusses MISO's external communications and identifies areas of improvement.

Lesson Learned: Recent operational events such as the 2020 hurricane season and the Arctic Event offer an opportunity to further collaborate with members and other industry groups to understand and deliver more effective communications going forward. By collaborating, all parties may avoid or mitigate negative press, concern from legislators and regulators, and ultimately customer frustration.

Actions to Address:

- *MISO will increase coordination with utilities, regulators, and others to ensure consistent messaging and to determine how and when to make emergency public appeals for conservation in the near term. MISO will schedule a communication-focused event focused on crisis communications.*
- *Reinforce communications lessons learned with member companies during Hurricane Action Plan drills and Reliability Coordinator drills. Engage in identifying roles, responsibilities, dependencies, and processes for communications during winter and summer (including hurricane) readiness activities.*

Lesson Learned: Many entities, including members and reliability enforcement entities, requested data and meetings during and after the Arctic Event. Significant MISO time, including time from those in Operations, was required to respond to these inquiries or requests for information, and at times this support pulled people away from responding to the event.

Actions to address:

- *Proactively assess internal, regulator, and stakeholder data needs to identify sources for the data and standardize the format for delivering the data.*
- *Leverage this Arctic Event Report as well as other Reliability Imperative messaging to raise emerging issues and provide context for stakeholders, state regulators, and federal regulators.*
- *Promote use of the newly launched MISO Mobile app, which gives users access to MISO's real time data visualization tools (LMP Contour Map, Real-Time Total Load, and Real-Time Fuel Mix). MISO Mobile also provides important real-time notifications and alerts.*

MISO's Response to the Independent Market Monitor

At the Markets Committee of the MISO Board of Directors meeting on March 23, 2021, the MISO Independent Market Monitor (IMM) presented on the IMM Quarterly Report covering the Winter 2021 period. The IMM presentation found that:

- The MISO markets performed competitively this winter, despite frequent mitigation due to offer capping, and conduct was competitive overall.
- Extremely cold weather, tight conditions, and high gas prices in February contributed to a 75 percent increase in energy prices from last winter.
- Average energy prices rose 10 percent in the first two months of the quarter and 226 percent in February because of the Artic Event in February.
- In the first two months, gas prices increased by 24 percent over the prior year; however, in February gas prices were 12 times as high as in 2020.
- Average and peak load grew 3 and 8 percent, respectively, from last winter because of the colder conditions.
- Very high gas prices and transmission emergencies led to:

- Real-time congestion at a record quarterly level of $1.1 billion, which is more congestion than occurred in MISO during all of 2019; and
- Real-time and day-ahead Revenue Sufficiency Guarantee payments totaled $125 million and $45 million, respectively. This includes costs verified above the $1,000 and $2,000/MWh soft and hard offer caps.

The IMM stated that "MISO's operators performed well under extremely stressful conditions...[and] maintained the stability of the system and avoided the more severe reliability outcomes that occurred in neighboring markets." He cites the following key lessons learned and improvements based on this event:

1. Improve procedures to invoke transmission line-loading relief (TLRs) earlier in advance of a transmission emergency and associated actions.
2. Increase Transmission Constraint Demand Curves during emergencies to ensure pricing and dispatch reflects the emergency conditions.
3. Derate the Regional Dispatch Transfer (RDT) after shedding load in a MISO sub-region to create headroom for load to return sooner.
4. Modify sub-regional emergency procedures to utilize curtailments of non-firm exports that consume the Regional Dispatch Transfer (RDT) interface.
5. Define and/or activate market to market (M2M) constraints as quickly as possible to ensure partners provide available relief and pay for their share of the overloads.
6. Ensure that emergency pricing and shortage pricing is applied consistently in capacity and transmission emergencies.

MISO's ongoing Resource Availability and Need focus on Scarcity Pricing address several of these issues and our response to the IMM's State of the Market will respond to application of emergency and scarcity for capacity and transmission emergencies.

Appendix: Lessons Learned and Actions Summary Table

	Lessons Learned	Actions to Address
1	While MISO's robust grid, along with its ability to import power from outside of the region, resulted in relatively limited impacts during the Arctic Event, MISO needs to continue evolving its transmission system in response to the changing resource mix and evolving grid. The anticipated changes in resource mix and extreme weather puts increased urgency on transmission planning.	• MISO will leverage the Long Range Transmission Planning (LRTP) activities to identify intra- and inter-regional planning to ensure reliability as the resource mix continues to evolve and disruptive weather events become more frequent. In particular, LRTP will evaluate further north-south transfer capability which would have helped during the Arctic Event. • Transfer capability - MISO will examine load pockets as part of transmission planning and resource accreditation. • Along with LRTP, MISO will also continue to work with all of its seams partners to identify ways to increase coordination. For example, MISO and SPP are currently engaged in an effort focused on the SPP – MISO seam.
2	MISO's resource adequacy construct provided transparency about adequacy of resources to meet projected summer loads. However, improvements can be made to more fully account for the non-summer risks and to ensure that resources will be available across all seasons. MISO has already seen and anticipates continued reliability challenges throughout the year – while reliability risk was once concentrated in the summer season, MISO now has to be	• MISO is moving to a sub-annual (4 season) resource adequacy construct and an accrediting methodology based in part on a resources' availability during the hours when the system is most in need (tight operating hours), thereby giving resource owners an incentive to ensure resources availability through investments in winterization, fuel assurance or other means. These changes are expected to be filed at the Federal Energy Regulatory Commission (FERC) in the second half of 2021.

	increasingly concerned with every hour of the year.	
3	Current resource accreditation criteria do not specifically address generator readiness to operate during extreme weather events. With the rapid fleet transition toward natural gas and the increased frequency and severity of extreme weather, this issue is expected to worsen over time.	• MISO will work with states and others to identify changes that may be required in MISO processes or elsewhere, to better reflect resource availability during extreme weather events (e.g., winterization needs during extreme cold, fuel assurance). • MISO will consider the impacts of the generation fleet change on the need for additional coordination with the natural gas sector on issues of fuel assurance.
4	In reporting results of Seasonal Assessments, MISO and stakeholders have not typically focused as much on the extreme cases (high load + high outages).	• MISO will focus more attention on extreme outcomes as well as expected outcomes during seasonal assessment workshops. • MISO will evaluate how to incorporate existing extreme cases into Seasonal Assessments and drills.
5	Current emergency load reduction plans are focused on summer needs. This new experience provides an opportunity for MISO and stakeholders to assess preparation for winter events.	• MISO will investigate the feasibility of a pre-winter feedback loop, which would allow members to express their readiness for the winter weather. This feedback would include information about generator weatherization and winter checklist completion. • MISO will encourage Local Balancing Authorities (LBAs) to refine emergency load reduction plans to include winter event load shedding, when cutting power can have different consequences than in the summer. MISO will encourage the refined emergency load reduction plans to consider which elements are critical and what to do if the requested emergency load reduction exceeds their capacity to rotate outages.

		• *MISO will seek additional feedback from stakeholders on their learnings from past events during the Seasonal Assessment workshops.* •
6	In extreme events, energy flows may be very different than those seen under normal operations. During the Arctic Event, MISO experienced very high flows across its system, and in an unusual direction as power was flowing from the (relatively warm) east coast to the more impacted central part of the country. With the increased severity of extreme events, it will become more important to plan for these scenarios.	• MISO will include the impacts of high wheel through flows in the seasonal transmission assessment to better prepare for extreme weather events.
7	Based on experience during the Arctic Event and the significant number of generator outages based on cold weather conditions, MISO believes that additional data, provided by additional survey participation, will help to inform decisions made during future extreme weather events.	• MISO is combining the Winterization and Annual Gas Fuel surveys and removing all backward-looking and redundant questions, with the goal of increasing participation in the survey. MISO will consider additional ways of accessing this information, including engaging in the process to develop NERC Cold Weather standards to be reflective of the increased risks seen during the Arctic Event. • Incorporate fuel assurance into scenario planning and drills, with a particular focus on MISO visibility into fuel plans.
8	Drills have been helpful in coordinating among operations staff. Given the wide scope of the Arctic Event, the drills were not sufficiently	• Increase comprehensive drills for extreme events – including operations, outage coordination, emergency load reduction planning, communications, and regulatory coordination. MISO

	comprehensive. In recent years, MISO has shifted to more tabletop exercises with specific groups (e.g., outage coordination or cyber security). However, the Arctic Event and the expected growth in similar extreme weather events in the future points to the need for comprehensive drills that include more groups across MISO and member utilities.	plans to incorporate more fuel assurance scenarios and responses into planning and drilling.
9	MISO's ability to accurately forecast weather conditions directly leading up to and during the Arctic Event, facilitated by having a meteorologist on staff, gave MISO the opportunity to prepare in advance, including issuing Informational Advisories early in the week prior to the event, reminding members to accurately reflect projected fuel supply access and availability to their generation and resource offers. These advisories also requested members implement any winterization processes and maintenance for generation resources in the footprint and confirm fuel supply availability through the President's Day holiday.	• MISO will continue to leverage in-house and vendor meteorology expertise to inform MISO operational decisions and communication with members. MISO is continuing to assess how best to translate accurate weather forecasts into accurate forecasts of the effects of the weather (e.g., outages tied to weather).
10	MISO's current process to identify available uncommitted resources is	• In order to provide more visibility into available units, MISO is preparing an Available Resource report as part of the Capacity

	tedious, takes more time than necessary, and does not always leave sufficient time to start resources with a long lead time. The spreadsheet-based tool currently used to identify resources must be operated manually each time it is needed, taking upwards of five minutes to compile necessary information.	Sufficiency Analysis Tool (CSAT) to communicate to MISO commitment teams the resources available for commitment. The report provides a list of resources available for capacity at any given point in time and helps operations make commitment decisions during tight operating conditions by producing a dynamic list of resources, meaning that a resource will automatically drop off the available commitment list if its window for start-up has passed for any given hour.
11	The Regional Dispatch Transfer (RDT) can be more effectively managed during emergency operating conditions.	• Since identifying this action item following the 2018 Cold Weather Event, MISO has improved communication with Joint Parties on RTD exceedances. MISO will continue to look for ways to better coordinate with Joint Parties. • When MISO requests a RDT limit increase and one or more of the Joint Parties deny MISO's request, MISO needs a better understanding of Joint Parties' system challenges such as congestion, flows, and outages, and reasons for MISO's request for a limit increase is being denied. MISO plans to address this issue in the current contract renegotiations. • Review schedules at a more granular level and target cuts to those with greater impact to RDT. Develop a tool that MISO operations can use to visualize what is driving impacts to the RDT. • Increase the shadow price for RDT prior to emergency events. Increasing the RDT shadow prices will limit flows and allow more efficient management of the RDT limit.
12	The current market design during transmission emergency events may not lead to efficient economic outcomes that support system	• Investigate and evaluate market price efficiency during Emergency Events requiring emergency load reduction below the Local Resource Zone levels in order to produce prices consistent with system conditions.

	reliability. Operating procedures and market capabilities need to be aligned, and in some cases enhanced, to result in real time prices that reflect system conditions, producing economic outcomes that support system reliability.	• Investigate and evaluate the allocation of Real-Time Excess Congestion, including Revenue Neutrality Uplift costs, due to scarcity pricing. • Investigate ways to ensure that preliminary prices are representative of settlement prices during Step 5 emergency load reduction events. *Implementation of such changes will have to be prioritized in light of MISO's Market System Enhancements acceleration effort.*
13	Additional and improved technology tools to support operator decision making will be helpful in future events as the increase in extreme weather and fleet change will continue to present visualization and decision-making challenges.	• Design tools to provide better visualization of the system and its pain points. • Implement more efficient analysis programs to more easily and quickly inform operators of critical information needed to inform decision-making, such as a tool to help MISO understand the drivers of the RDT calculation.
14	The Arctic Event and the extensive use of collaboration tools presented an opportunity to train newer Operators without their being in the middle of the event response.	• MISO will continue to leverage collaboration tools to allow newer Operations staff to observe during real-world emergency events.
15	(Bankruptcy and Default Provisions) The specific bankruptcy issue was the first of its kind in the MISO markets because the defaulting party is a load serving entity that did not name MISO as a critical vendor in the bankruptcy. The bankruptcy law puts an automatic stay in place in the action which prohibits MISO from sending certain notices, such as a	• MISO is evaluating if Tariff amendments will help MISO address these types of situations in the future. A potential solution is amending the Tariff to modify the notice process required to parties to resolve the conflicts recently experienced.

	notice of default, to the party. This creates misalignment with requirements and actions required in the Tariff, including Section 7 of Module A.	
16	(Alternative Credit Exposure Calculations) During the Arctic Event, it became apparent that MISO would over collateralize several members under the Tariff, indicating that MISO needs a modification in the Tariff to account for impacts from extreme pricing events.	• To better address potential future events, MISO may seek to revise the Tariff and allow for alternative calculations that may be used in extreme pricing volatility events with appropriate notifications to parties. This would be more efficient than requesting an emergency waiver from FERC in the middle of an event; and • MISO is evaluating using the preliminary Locational Marginal Pricing and telemetry data in the credit exposure calculation to cover the expected future S7 settlements. If this approach works, MISO's Credit Policy would need to be revised.
17	(Minimum Capitalization) The low minimum capitalization requirements in the Tariff may be insufficient in protecting the market in extreme pricing events.	• Due to increased market price volatility, the minimum capitalization requirements are being evaluated to determine in what instances they provide inadequate protection for the market. Other RTO/ISOs have already made or are considering revisions in this area. MISO is working with the other RTO/ISOs for awareness and potential standardization within the industry.
18	(Unsecured Credit) Unsecured credit provides a benefit to market participants; however, it also can create unexpected market exposure in extreme pricing events as some market participants may have no cash collateral posted with MISO to offset or cover market defaults.	• MISO is evaluating approaches that might be used to determine prudent minimum cash equivalent collateral level for market participants, thereby, providing at least some protection to the market in the event of extreme market pricing volatility.

19	Recent operational events such as the 2020 hurricane season and the Arctic Event offer an opportunity to further collaborate with members and other industry groups to understand and deliver more effective communications going forward. By collaborating, all parties may avoid or mitigate negative press, concern from legislators and regulators, and ultimately customer frustration.	• MISO will increase coordination with utilities, regulators, and others to ensure consistent messaging and to determine how and when to make emergency public appeals for conservation in the near term. MISO will schedule a communication-focused event focused on crisis communications. • Reinforce communications lessons learned with member companies during Hurricane Action Plan drills and Reliability Coordinator drills. Engage in identifying roles, responsibilities, dependencies, and processes for communications during winter and summer (including hurricane) readiness activities.
20	Many entities, including members and reliability enforcement entities, requested data and meetings during and after the Arctic Event. Significant MISO time, including time from those in Operations, was required to respond to these inquiries or requests for information, and at times this support pulled people away from responding to the event.	• Proactively assess internal, regulator, and stakeholder data needs to identify sources for the data and standardize the format for delivering the data. • Leverage this Arctic Event Report as well as other Reliability Imperative messaging to raise emerging issues and provide context for stakeholders, state regulators, and federal regulators. • Promote use of the newly launched MISO Mobile app, which gives users access to MISO's real time data visualization tools (LMP Contour Map, Real-Time Total Load, and Real-Time Fuel Mix). MISO Mobile also provides important real-time notifications and alerts.

MISO'S RESPONSE TO THE RELIABILITY IMPERATIVE

- DECEMBER 2020 -

Living Document

MISO is releasing this report as a "living" document which will be updated over time as conditions evolve and as MISO, stakeholders, and states continue to learn about the Reliability Imperative

Public

Contents

A Message from John Bear, CEO

The electric industry is changing in profound ways.

The industry's longtime reliance on conventional baseload power plants is declining sharply, driven by economic factors and consumer preferences for clean energy, among other things.

Meanwhile, the grid is becoming increasingly reliant on wind and solar resources that are available only when the wind is blowing, or the sun is shining.

To be sure, there are upsides and opportunities associated with these trends. But the changes we are seeing also pose a host of complex and urgent challenges to electric system reliability in the MISO region.

Utilities, states, and MISO all have roles to play to address these challenges. MISO calls this shared responsibility the **Reliability Imperative.** We think the word "imperative" is appropriate for several reasons. First, the work we are doing is not optional—to maintain system reliability, we must respond to the unprecedented change we and our members face. Second, this work cannot be put off for months or years—much of it has long lead times, so we need to act now. And third, our stakeholders are counting on us—regulatory agencies, utilities and other entities are looking to MISO to identify problems and find solutions.

This report describes the many interconnected efforts that MISO is pursuing in the realms of markets, operations, and planning to meet that charge. The report is also designed to be "living" so it will be regularly updated and expanded as we learn more and our path forward becomes clearer.

The energy industry and our region are changing in big ways, and MISO is planning for what lies ahead. We hope you will find this report to be engaging and useful as we confront these new challenges and opportunities together.

Thank you,

Executive Summary

THE REGION IS CHANGING IN BIG WAYS

The electric system is increasingly fueled by wind and solar, driven by favorable economics for energy production, technological advances, state policies, and consumer preferences for carbon-free energy, among other things.

Looking at the marginal cost of energy produced, wind and solar are lower cost than coal, nuclear, or natural gas generation. As a result, the growth of these renewable resources continues to replace the region's conventional baseload resources that constituted the backbone of the region's electric system for decades.

There are many system and societal benefits of these changes. Innovative generation and grid technologies have the potential to reduce customer rates and bring efficiencies to the system. The shift to cleaner fuels will benefit the health of our communities and is key to addressing the risks of a changing climate. With a diverse regional footprint and managing all of the connections with our seams neighbors, MISO is well-positioned to support our members as they transition their fleets.

THESE CHANGES WILL CHALLENGE SYSTEM RELIABILITY

While MISO is policy-neutral on these and other trends, MISO has observed they pose a number of significant challenges for the region's electric system and we must adapt to maintain required and expected levels of reliability. As the independent system operator, MISO has responsibility to maintain electric reliability, which it does by addressing the holistic needs of the system – for example for energy, capacity, resource adequacy, and flexibility.

Each resource type provides a different mix of these capabilities. As the region's resource mix changes, we must understand what capabilities are needed to maintain reliability and ensure that sufficient amounts of those resource capabilities are available when needed.

- Wind and solar resources are not always available to provide energy during times of need.
- Conventional baseload resources that remain in service can be more prone to outages given their changed usage patterns and maintenance cycles, rendering them potentially unavailable when they are needed most.

As the system relies more on renewables, the region is also becoming more dependent on resources connected to local distribution systems or located behind customer meters, as well as on demand-side resources that currently are only used in emergencies. Generation fleet change and extreme weather are increasing risk across the entire year (not just in the summer). MISO's Renewable Integration Impact Assessment concludes that the complexity of planning and operating the grid increases exponentially beyond 30% of the load being served by wind and solar, requiring more coordination and advanced action to maintain grid stability at higher renewable penetration levels. Already there are areas within the MISO system where local renewable penetration is above 30%.

WE HAVE A RELIABILITY IMPERATIVE TO ADDRESS THESE CHALLENGES

MISO, members, state regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges. MISO calls this shared responsibility the MISO Region Reliability Imperative because the reliability-enhancing work it requires cannot be delayed. This work will also enable utilities and states in the MISO region to invest in the type of infrastructure that is needed to meet energy needs and policy objectives going forward.

This report lays out MISO's response to the Reliability Imperative. MISO's response is holistic in approach, consisting of numerous efforts and initiatives that are designed to work in concert with each other to mitigate the challenges facing the region. MISO organizes this work into four main categories: (1) Market Redefinition, (2) Long Range Transmission Planning, (3) Operations of the Future, and (4) Market System Enhancements. Below is a brief look at each.

1. **Market Redefinition:** The initiatives in this category aim to ensure that resources with the types of capabilities and attributes the system needs will be available in all 8,760 hours of the year. This is important because as noted above, the region is increasingly facing reliability risks outside of the summer peak-load months that historically posed the greatest challenges. Specific efforts in this area include providing a longer-term and deeper assessment of system needs across all hours of the year, including required capabilities such as flexibility; shifting to verifying sufficient generation adequacy across all hours of the year; improving how resources are accredited; ensuring that prices accurately reflect market conditions, especially during emergencies; and development of market products that provide the right incentives for resources to maintain system reliability.

2. **Long Range Transmission Planning:** This effort is designed to identify what transmission the region will need going forward as the electric industry continues to evolve. For example, building additional transmission is especially crucial to support the continued growth of large-scale wind and solar, since those resources are often located far from load centers. A robust transmission plan can also reduce the cost of electricity for consumers by signaling better locations for resource siting that deliver fuel cost savings, decarbonization, and flexibility.

3. **Operations of the Future:** This effort is designed to ensure that MISO will have the kinds of skills, processes, and technologies it will need to effectively manage both wholesale and retail connected resources. For example, this initiative will leverage artificial intelligence, machine learning and advanced analytics among other tools to help future MISO control-room operators effectively forecast, visualize, and manage grid uncertainty. It will also help MISO to better manage maintenance and "pre-position" the grid ahead of system changes such as weather.

4. **Market System Enhancements:** This category of work is designed to transform MISO's historical system—which was built in the early 2000's—into a more flexible and secure system that will meet the needs for years to come. Current systems and technology are not capable of accommodating the increasing demands for new, reliability-driven market enhancements and fully leveraging the opportunities of new resource types such as storage and residential generation options (like rooftop solar) to meet future challenges. This initiative will employ flexible architecture and analysis to support the evolving resource mix and future-state processes for operating MISO markets.

PURPOSE OF THIS REPORT

The purpose of this report is to provide MISO stakeholders with an organization-wide view of MISO's plan to address the Reliability Imperative amidst a rapidly changing energy landscape. The goal of this "living" report is to lay out the context for critical Reliability Imperative initiatives, how they fit together, feedback plans and project timing. This "living" report will be updated with accompanying materials as specific plans mature and additional information is gathered.

While grid operators have managed uncertainty for decades, and MISO has continuously pushed to improve and evolve since day one, we are preparing for an unprecedented pace of change. By actively pursuing this strategic collection of coordinated initiatives, MISO will ensure ongoing system reliability while enabling members' future plans. There is a huge amount of work to do and we will only succeed if we move forward transparently, collaboratively and swiftly.

STAKEHOLDER INPUT IS CRUCIAL

Much of the work cited in this report is already underway. Many of the ideas and proposals in this report reflect a great deal of technical input from stakeholders. For example:

- MISO proposals to assess resource adequacy more than once a year and to improve how resources are accounted for are discussed at the MISO Resource Adequacy Subcommittee.
- Similarly, MISO initiatives for emergency pricing and the Market System Enhancement effort reflect input at the MISO Market Subcommittee.
- Member plans and stakeholder input shaped the MISO Futures planning scenarios over multiple workshops.

Other proposals in this report are not in the stakeholder process because they are in development and not yet ready to be discussed with stakeholders or they are focused on internal MISO processes.

THE RELIABILITY IMPERATIVE DOES NOT REPLACE EXISTING INITIATIVES OR PROGRAMS

This report, and the initiatives it describes, should not be viewed as a brand-new effort by MISO. The Reliability Imperative is not intended to replace existing initiatives that stakeholders are already familiar with. Instead, this report brings together a number of strategic initiatives with the purpose of ensuring more alignment and highlighting the connections.

That said, this report is written from MISO's perspective. Not every proposal and initiative in this report will be supported by every one of MISO's stakeholders, given the range of policy goals, business models, and other interests. MISO welcomes feedback on this report but MISO also recognizes that the Reliability Imperative warrants an immediate response. The time to act is now.

Informing MISO's Response to the Reliability Imperative

MISO's response to the Reliability Imperative has been informed by years of conversations with our stakeholders. Additionally, MISO has performed extensive modeling of the changing risk profile. To review:

MISO Forward 2019: The first of the Forward series described the implications of a changing resource mix, including how the '3Ds' – de-marginalization, decentralization, and digitalization – led to MISO's focus on enhancing Availability, Flexibility and Visibility ("AFV"). You will find these themes in the Reliability Imperative initiatives. These AFV themes have informed much of the following MISO work.

MISO Forward 2020: The MISO Forward 2020 report shows that changes will not be the same across all members, as different states and utilities adopt a range of business models and generation, all of which MISO will support through the Reliability Imperative work.

Renewable Integration Impact Assessment (RIIA): MISO's 4-year initiative to understand the impacts of increasing renewables on the MISO system. The key conclusion is that planning and operating the grid becomes more difficult beyond 30% of the footprint-wide load being served by wind and solar, and that with coordination and advanced action the MISO region could achieve 50% or higher. The workshop materials are available now, and a report will be published in early 2021.

Resource Availability and Need (RAN) Initiative: Ongoing analysis of MISO's changing risk profile and evolving system needs as outlined in five whitepapers. The analysis has informed changes to the value of wholesale load that can respond to the market and plant outage coordination, and development of resource adequacy changes. Because Resource Adequacy must compliment market design and real-time tools/process, the work is central to the Reliability Imperative effort.

MISO Futures: A product of continued collaboration between MISO and its stakeholders, the three MISO Futures provide a set of bookends to explore a wide range of future outlooks. Updated this year with the annual transmission planning cycle, these forward-looking planning scenarios are being used throughout the organization to prioritize and pace the Reliability Imperative work.

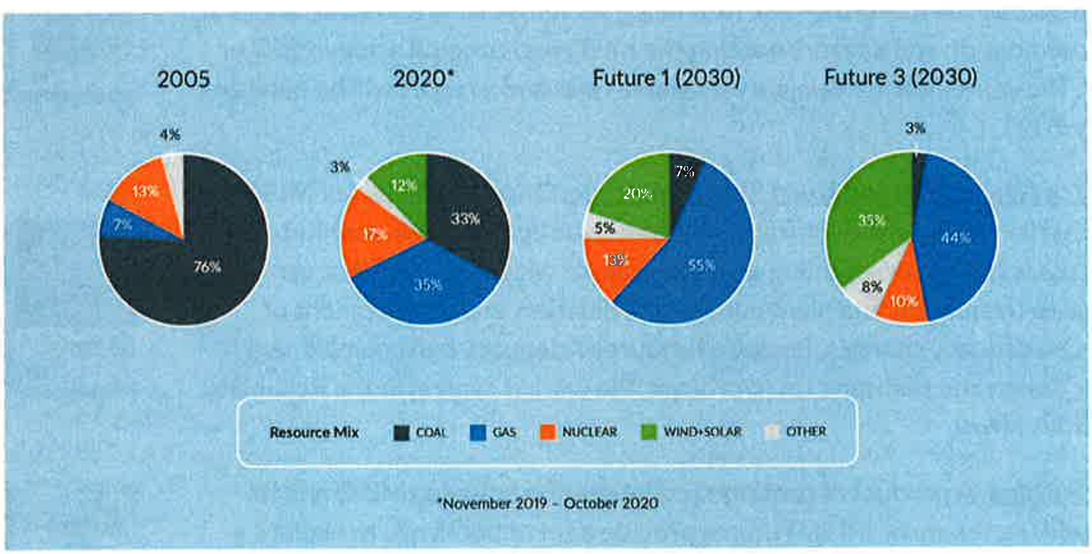
MISO Forward 2021: To be published early 2021, the next report in the Forward series will focus on what changes are needed from MISO as adjacent industries, such as buildings and transportation, evolve how they interact with the electric ecosystem. The Reliability Imperative will remain closely in step with these expectations.

From this groundwork, we know that there are challenges ahead. But we can also see that there is opportunity for the large, interconnected footprint that MISO provides. We are determined to do the hard work required to ensure all of our members and their end consumers benefit from MISO membership.

The timing of much of the Reliability Imperative work will be impacted by the pace of new generation coming on the system. MISO has multiple views on the future generation fleet and, importantly, the speed of change being set by our members. MISO is currently operating a 25,000 MW wind fleet which, in MISO's most recent 12-month history generated 12% of the electricity mix (solar less than 1%). MISO is preparing for an additional 15,000 MW of renewables (10,000 MW of solar and 5,000 MW of wind) on the system in the next few years.

Beyond that, MISO looks to the [MISO Futures] modeling to capture the bookends of resource mix possibilities. The figure below shows 2030 planning scenarios for the conservative pace of change (Future 1) and the more aggressive pace (Future 3):

MISO Generation Mix (% of MWh)



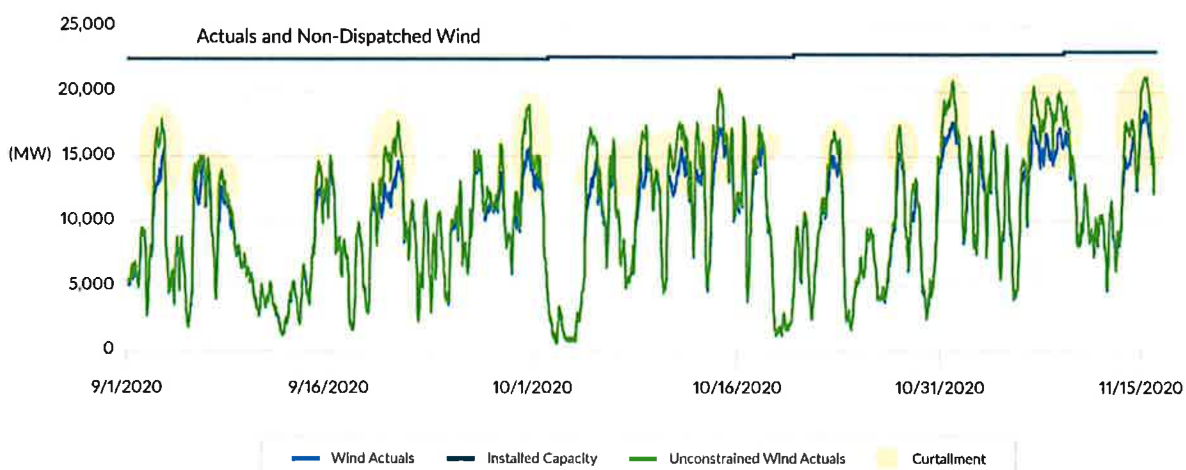
Public

Current Reliability Challenges Will Become More Significant

> "We see very little risk of over-building the transmission system; the real risk is in a scenario where we have underbuilt the system. Similarly, across markets and operations, our job is to be prepared."
>
> Clair Moeller, MISO President

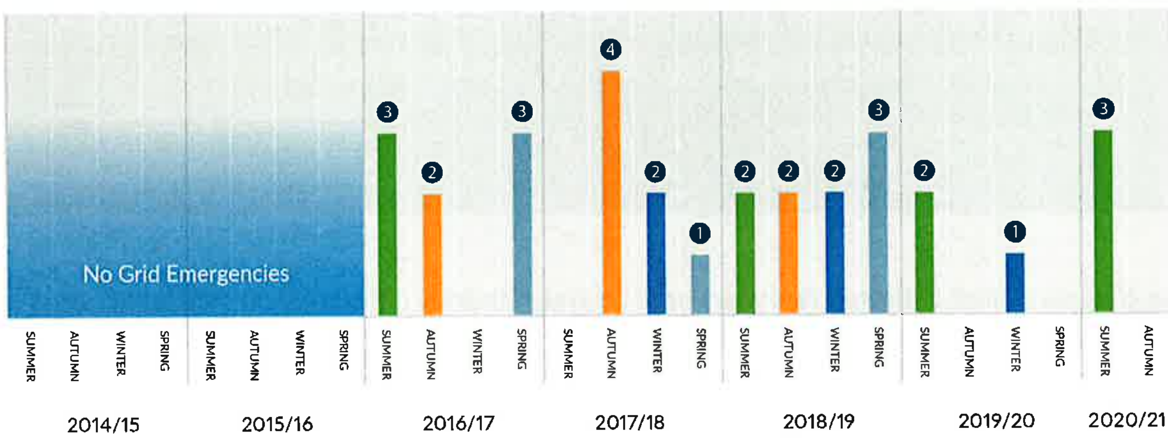
Real-time conditions in the last few years have been significantly different than the first 10 years of MISO operations. Power plant retirements, lower overall reserve margins, and increasing outage levels of conventional generation have required MISO to operate with less available capacity than in the past. A growing fleet of renewables that operate differently and, as the graphic below illustrates, can fluctuate on a day-to-day and even an hour-by-hour basis. At times of high wind output, transmission congestion is leading to increased levels of curtailment (highlighted by the orange circles in the chart below). Additionally, non-traditional resources such as load that can respond to system needs and energy efficiency are increasingly being used. And as the climate changes, history becomes a less reliable predictor of future conditions.

Recent Examples of MISO wind generation variability and curtailment



MISO has declared an increasing number of emergencies since the summer of 2016. While the emergency protocols are a legitimate way for MISO to access additional resources and not a direct indicator of a reliability issue, calling on them more and in non-traditional times are evidence of MISO's changing risk profile.

MaxGen Alerts, Warnings, and Events



Most events are the result of multiple factors happening at the same time. Factors include more planned and/or unplanned generation and transmission outages, high demand conditions, and more extreme temperatures and storms.

Market Redefinition

Generation mix evolution increases the focus on having enough energy for every hour of the year. MISO is addressing this changing risk profile across markets, planning, and future-looking studies. As the generation mix changes, it is important for MISO to provide signals about what will be needed to ensure reliability, and to give the right price incentives when the system is in need. Markets can provide useful signals across multiple time frames.

Resource Assessments: In the investment and planning timeframe, MISO should provide information to all members about the impact of their plans in aggregate. Today, planning is focused on the summer peak hour for the coming year or two. The voluntary Organization of MISO States (OMS) survey looks at several years ahead, but confidence is lower in the later years. Additionally, the OMS survey only focuses on capacity, but increasingly the system will need a forecast of flexibility and other attributesGoing forward, MISO is developing the ability to provide forward resource assessments and long-term resource adequacy reports to better inform future investment and retirement decisions.

Meeting Forecasted Needs: Currently, MISO utilizes both planning requirements and energy market price signals to inform investment decisions and pay resources for providing energy when most needed. Since 2017, the Resource Availability and Need (RAN) initiative has focused on near-term improvements in both planning requirements and energy markets. MISO, and the electric industry in general, are also considering the right balance between planning requirements and energy markets in ensuring energy is available in every hour of the year; for now MISO is focused on 'no regrets' modifications for both planning and markets. One important group of changes looks at updating how resources are accredited – including conventional, intermittent, and emergency-only resources.

Resource Adequacy Construct: In the planning horizon, MISO is looking to better reflect the changing risk profile. MISO's construct was designed around a conventional fleet of resources. In this system, outage risk was concentrated during the summer. Since the early 2000s, the fleet has moved to more renewable resources that are variable and outage risk has expanded beyond the summer months. MISO's mechanisms must be updated to reflect the changing risk. In the near term, MISO plans to make the Planning Resource Auction a "sub-annual" construct to reflect the changing risks. Importantly, the future Resource Adequacy construct will also need to be adaptable as the portfolio and risk profiles continue to evolve.

Increased Reliance on Energy Market Pricing: MISO is working to update prices to more accurately reflect the value of additional energy during times of system constraints. MISO is in the process of improving emergency and scarcity prices to more accurately convey system conditions and help incent and ensure reliability in tight grid conditions. MISO will continue to evaluate the changing risk profile to assess the effectiveness of energy market products and pricing and will explore potential new products and approaches.

"Market Redefinition means we need to consider the broad and transformative implications of the rapidly changing risk profile in MISO. This is driving our agenda to re-think the methods by which we assess reliability risk in the planning and operating horizons and the ways in which our markets incent and ensure availability and flexibility."

Richard Doying, MISO EVP Market & Grid Strategy

MARKET REDEFINITION ACTIONS (BASED ON CURRENT INFORMATION)

	Explore	Decide	Do	Done
Resource Adequacy Construct	• Regional resource assessments of changing reliability risk profile	• Reliability requirements & metrics • Sub-annual construct • Accreditation enhancements		• Enhanced deliverability for conventional and intermittent capacity resources (Installed Capacity filings) • Load Modifying Resources Accreditation
Energy Market Signals	• Uncertainty and variability management • Emerging technology participation (e.g. hybrid and Distributed Energy Resources) • Optimize transactions at the seams (transmission & distribution interface, and bulk electric system)	• Improve scarcity pricing and price formation • Enhancements for long-lead units and self-commitments • Multiple Configuration Resources • FERC Order 2222 (Distributed Energy Resource) compliance plan • Enhance market-to-market coordination process	• Enhance emergency pricing • Build Short-Term Reserves product • FERC Order 841 (storage participation) product	• Multi-day Operating Margin forecast • Distributed Energy Resource Visibility and Communication whitepaper • Improvements to MISO-SPP & MISO-PJM market-to-market process

Long Range Transmission Planning

Renewables such as wind and solar work with the transmission system very differently than conventional power plants. For this reason, the ongoing trend of conventional resources retiring from service as intermittent renewables continue to grow poses significant challenges to the reliability of the transmission system in the MISO region. These challenges are framed up in MISO's Renewable Integration Impact Assessment work.

Fortunately, MISO can leverage its large footprint and resources to ease some of the challenges. One of the keys will be transmission projects that support these new resources in the region.

MISO is doing this through a Reliability Imperative initiative called Long Range Transmission Planning, or LRTP. LRTP is designed to assess the region's future transmission needs, starting from a base of the utility and state plans on where to site and build new resources.

It is important to keep in mind that LRTP does not replace other transmission-planning efforts that have long existed at MISO, such as the annual studies contained in the MISO Transmission Expansion Plan, or MTEP. LRTP will coordinate closely with those efforts, and it will also be a transparent and cooperative part of the MISO stakeholder process.

Futures / Policy Consensus: The LRTP work is grounded in the three robust future scenarios developed over the past year. MISO will prioritize meeting the reliability challenges embedded in Future 1, while ensuring that outcomes do not foreclose Futures 2 and 3. Future 1 tries to reflect current MISO member plans across the footprint and various policy objectives of the states. Futures 2 and 3 reflect increasing levels of electrification (e.g., more electric vehicles) and renewables.

Business Case Development: MISO will help stakeholders assess the business case for LRTP projects by analyzing multiple benefits relative to the costs. The business case should reflect the need for transmission to ensure reliability of the system, in addition to any economic benefits, given the policy and fleet transition objectives of stakeholders. This includes helping stakeholders consider both generation and transmission costs and benefits on a holistic basis, including the value of flexibility that transmission provides. For example, we will need to assess: (1) congestion points that limit energy imports into certain zones; (2) constraints between the MISO South subregion and the North/Central subregions; and (3) energy transfers between MISO and neighboring systems, such as Southwest Power Pool and PJM.

Cost Allocation: A key aspect of LRTP will be to ensure that the costs of new transmission projects are allocated fairly. This means MISO and stakeholders will work together to adjust existing or develop new cost-allocation methods. The Organization of MISO States (OMS), which represents our state regulatory agencies, has established a working group to focus specifically on transmission cost allocation issues. MISO is committed to working with that OMS group and other stakeholders on this important topic.

LRTP is a comprehensive "transmission roadmap" that will identify and drive investments in transmission projects addressing all needs of the region as the resource fleet continues to evolve. The roadmap will be updated as needed to align with evolving resource fleets and business plans, state energy/environmental policies, and other dynamic factors that affect the region's transmission needs. As solutions are identified through LRTP, they will be moved into the ongoing MTEP process for final approval by MISO management and Board of Directors. MISO anticipates delivering the first round of suggested LRTP solutions to the Board of Directors in December 2021. Specific projects in the Explore, Decide, Do table will inform recommendations.

> "If you love renewables you'd better love transmission."
>
> John Bear, MISO Chief Executive Officer

LONG RANGE TRANSMISSION PLANNING ACTIONS (BASED ON CURRENT INFORMATION)

	Explore	Decide	Do	Done
Futures / Policy Consensus			• Continue to understand member plans, Integrated Resource Plan trends, state policy objectives	• Update MISO Futures
Business Case Development	• Study non-transmission alternative solutions • Determine increased potential for High Voltage Direct Current (HVDC) lines	• Conduct special zonal studies • Deliver first round of suggested Long Range Transmission Plan solutions to MISO's Board	• Increase MISO North/South transfer capabilities • Enhance renewables integration in the upper Midwest (MWEX-area) • Address import / export limitations in Michigan • Improve seams via Joint Study with SPP	• Multi-Value transmission projects • Ongoing improvements to the generation interconnection process
Cost Allocation	• Benefits/Cost allocation for identified Long Range Transmission Plan projects			

Operations of the Future

MISO Operations will also be challenged by the different types of resources connecting to the grid including at the residential level. Work is underway to ensure that the people, processes, and technology allow MISO to respond. This work, termed Operations of the Future, is initially focused in the near-term on two large buckets of work – operational planning and situational awareness.

Operations planning improvements can help manage supply and demand variability in every hour. The shift to more weather-dependent, intermittent renewables and distributed resources mean that system peaks and operating risks are becoming less obvious and more difficult to manage in day to day operations. The planning assumption that most days follow predictable load profiles is also being challenged given the rise of demand responding to market prices. With the changes in the system, better forecasting will capture more unknows into operations and market decisions. Outage coordination will also be enhanced to determine and approve planned maintenance outages, thus providing more windows of opportunity. MISO is further investigating enhanced 'look-ahead' commitment of both generation and demand to capitalize on the flexibility of the grid to meet various system conditions. Finally, MISO is seeking improved methods to position the grid ahead of system challenges such as volatile weather patterns and improve our preparation and management of grid events.

> "In the past, most days were the same. In the future, most days will be different and we need the people, process and technology to deal with that variability.
>
> Jennifer Curran, MISO VP System Planning and Chief Compliance Officer

Situational awareness can be improved to turn data into actions. Today, MISO Operations relies heavily on the expertise of its operators. While operators have access to lots of data (e.g., weather, load), they must manually synthesize data into useable information. This has worked well historically, but as the system changes the solution must envision a future with more complex information and less experienced operators. In the future, MISO Operations is looking to have an integrated toolset for operators that leverages artificial intelligence and machine learning. Techniques to improve how we see and navigate will give operators important information automatically.

OPERATIONS OF THE FUTURE ACTIONS (BASED ON CURRENT INFORMATION)

	Explore	Decide	Do	Done
Situational Awareness	• Advanced MISO visualization techniques • Intelligent alarming • Decision support systems leveraging artificial intelligence / machine learning	• Smart transmission technologies (e.g. ambient adjusted and dynamic line ratings) • Advance synchrophasor applications	• Real time display replacement	• Assessment of real-time displays and energy management displays to inform the visualization roadmap
Operations Planning	• Look-ahead commitment products • Predictive scenario analysis • Outage coordination changes	• Enhanced forecasting		• Dispatchable Intermittent Resources forecasting
Operations Preparedness	• Operations simulation • Reliability product testing			
Critical Communications	• Operations communications • Event/operator logging			

Market System Enhancements

MISO's ability to respond to the Reliability Imperative will be enabled through continued market system enhancements and modeling. Current systems and technology are not capable of meeting the new, reliability driven market improvements and fully leveraging new resources such as storage and distributed energy resources. Even minimal changes to the market systems today require significant resources. The new system will allow more timely improvements to meet MISO's evolving needs.

Today, MISO's legacy system has limitations. Recent upgrades (e.g., MISO's Private Cloud launched in July 2020) will help inform future investments. The Market System Enhancement, or MSE Program, was formed in 2017 to transform our current market platform into a more flexible and secure system. The work is ongoing, but already has reached important milestones including extending the life of legacy systems, improvements to the Energy Management System while the larger upgrade is in-flight, and launching the Readiness Application for the Market User Interface (which will go into production in 2021).

> "MISO's Market System Enhancement Program will provide the platform for faster adoption of new technologies into the market and better accommodate the region's changing resource mix to ensure reliable and efficient operations for our customers."
>
> Todd Ramey, VP and Chief Digital Officer

Building on the MSE Program progress, flexible design, advanced data analytics, and model management will help MISO to meet the Reliability Imperative. In contrast to the current legacy technology, the future market platform will integrate technology and systems to better utilize data. Modern architecture means systems that provide flexibility for the evolving needs of the business. Across the various workstreams of the Reliability Imperative, MISO is establishing a portfolio management function to ensure that investments align with the long-term strategy, including meeting the risks of the changing resource fleet.

MARKET SYSTEM ENHANCEMENT ACTIONS (BASED ON CURRENT INFORMATION)

	Explore	Decide	Do	Done
Market System Enhancement		• Real-Time Market Clearing Engine	• Market User Interface • Model manager / data governance • Energy Management System (EMS) Upgrade • Day-Ahead Market Clearing Engine	• MISO Private Cloud • Extend life of legacy system
Technology and Portfolio Needs	• Develop and deploy data analytics • External Self-service data • Module E Capacity Tracking (MECT) tool assessment	• Update the MISO Communication System (MCS)		

Connections Between the Workstreams

The work described here is organized across four main workstreams – market redefinition, long range transmission planning, operations of the future, and market system enhancements. These workstreams are connected and build on each other. Also, success in one area depends on progress in another, so efforts must be coordinated and sequenced.

For example, given the changing resource fleet, providing reliable and economically efficient grid operations requires both new tools and process being developed under the Operations of the Future workstream, and market enhancements being developed under the Market Redefinition workstream. Additionally, the ability to interconnect renewable resources may be constrained by the existing transmission system and therefore dependent on some of the changes being contemplated in LRTP. In a similar vein, the ability for MISO to deploy enhanced situational awareness depends on the quality of our data deployed through MSE.

By documenting our future vision in this report, and outlining next steps across the four main workstreams, MISO is starting an important dialog about how to prioritize different work efforts. As we continue to update this "living" document, we believe the Reliability Imperative will note dependencies and impacts of any future schedule changes. MISO plans to continue the dialog by updating stakeholder committees regularly on the Reliability Imperative.

The Opportunity: Capturing the Value

As described in this paper, MISO sees the challenges of the changing resource fleet. We are facing a Reliability Imperative to prepare for the future, and MISO is hard at work on a number of key planning, operational, and systems efforts.

The fleet change represents not just challenges, but also enormous opportunities for MISO to enable members, states, regulators, and consumers to meet their objectives reliably and affordably.

By listening and taking a system-wide view, MISO can help ensure that all stakeholders have the right information.

By helping forward planning, MISO will help members to develop generation and transmission portfolios that maintain system reliability without over-investing. As member portfolios materialize, MISO markets and operations will optimize energy across the footprint. In addition, MISO will continue coordinating with our neighboring seams partners.

MISO has delivered substantial value to its members since its creation, as demonstrated by the annual Value Proposition calculation. Going forward, additional sources of value will emerge through the sharing of attributes across the diverse resource fleets. MISO is in the early stages of investigating how to calculate these new sources of value in an evolved, future-looking Value Proposition. Given changes to fleet, grid, market, and operations, it is more important than ever that the MISO region work together so that each member continues to realize the substantial benefits of our regional structure.

"MISO has the opportunity to help its States and Members reach their own policy goals in the most cost-effective way while also ensuring the reliable delivery of electricity to end-use customers."

Wayne Schug, MISO VP Strategy & Business Development

Working Together to Address the Reliability Imperative

This is a report written from MISO's perspective. It lays out MISO's proposals to address the challenges associated with the region's changing resource mix. As an independent, FERC-approved system operator, MISO is responsible for the reliability of the Bulk Electric System and has the authority to act.

But the responsibility for the Reliability Imperative is certainly not MISO's alone. Utilities, electric cooperatives, and other load-serving entities serve the load and own the region's transmission lines, generating units, and other infrastructure. State regulatory agencies also play an important role in overseeing how load-serving entities carry out their responsibilities.

Internal and external input

While this report focuses on MISO's ideas and proposals, it was heavily informed by technical and policy-related input we received from our members and other entities described above. Much of that input came from the formal MISO stakeholder process and its committees, which have expertise in markets, operations, and planning. MISO also received input from industry trade groups, consultants, and other entities with insights into the challenges that are facing our region.

MISO is committed to working closely with its stakeholders as we identify, design, and implement the Reliability Imperative. We believe that by doing so, we can continue to operate the system reliably and efficiently while also working with the differing utility business models and state energy policies in our region.

A Message from Clair Moeller, President

Utilities, states, and other stakeholders in the MISO region differ widely in terms of their policy goals, business models, and other interests. MISO knows that not all stakeholders will support every view, recommendation, and initiative that MISO lays out in this report. Concerns are sure to be raised in the stakeholder process, and perhaps beyond it as well.

That's OK. That's how it should work. That's how important issues like these should be debated. Our region is facing some very difficult and complex challenges, and no single entity—MISO included—has the perspective, experience, and wisdom to fix them singlehandedly. Everyone should be invested in the outcome. Everyone should offer up their ideas and their proposed solutions.

This report represents MISO's initial contribution to that effort—but it does not represent the last word on the subject. MISO welcomes stakeholder feedback on the proposals described in these pages, and if stakeholders have different ideas altogether, we want to hear them. Will we agree on everything? No. But that should not—and must not—stop us from working together to meet the obligations of the Reliability Imperative.

We also recognize that we will need to adjust our approach going forward as industry conditions and the needs of our stakeholders continue to evolve. We are committed to working cooperatively with all of our stakeholder sectors to address these long-term challenges. In the meantime, we will continue to address incremental enhancements needed to maintain reliable and efficient operations.

This report is a current, snapshot-in-time look at how we see the Reliability Imperative today, but we will revise our approach as we learn more.

The time to act is now – the industry is changing, and MISO members are poised to drive exciting, necessary changes over the coming years. Given the regional Reliability Imperative, MISO must act quickly and deliberately to ensure that the planning, markets, operations, and systems keep pace with our members' plans.

Let's get to work,

April 30, 2021

Arkansas Energy Resources Planning Taskforce
Sent via email: ERPTaskForce@adeq.state.ar.us

Re: February 2021 Weather Event; Regional Transmission Organizations

Dear Taskforce Members:

Southwest Power Pool, Inc. ("SPP") appreciates the opportunity to provide the Arkansas Energy Resources Planning Taskforce ("ERP Taskforce") with information relating to the winter weather event that occurred on February 4, 2021, through February 20, 2021 ("February 2021 Weather Event"). SPP provides responses to the ERP Taskforce's questions below:

1. Having had some time to do an analysis of your operations since the February 2021 Weather Event, could your organization provide a brief summary of your role in addressing the power outages during the February winter event.

Response 1:

During a special meeting March 2, 2021, SPP's Board of Directors approved a plan to assess SPP's performance, and that of its members and market participants, during the February 2021 Weather Event. The newly formed Comprehensive Review Steering Committee is currently overseeing five teams comprising representatives of SPP staff, stakeholders, the SPP Market Monitoring Unit ("MMU")[1], and the SPP Regional State Committee[2] ("SPP RSC"). The five teams will evaluate operational, financial, communications and other factors related to the events of the February 2021 Weather Event. The group will provide its final

[1] SPP's Market Monitor is responsible for monitoring SPP's Markets and services. The group's primary purpose is to ensure SPP's markets are efficient and fair. Specific duties include: Obtaining objective information about SPP's markets and services; Assessing the behavior of Market Participants (MPs); and Assessing the behavior of other markets and services that impact SPP.

[2] The SPP RSC provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission and is comprised of retail regulatory commissioners from agencies in Arkansas, Iowa, Kansas, Louisiana, Missouri, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota and Texas.

assessment and recommendations at the July 27, 2021 meeting of the SPP Board of Directors and Members Committee. The Midwest Reliability Organization ("MRO")[3], the Federal Energy Regulatory Commission ("FERC")[4], and the North American Energy Reliability Corporation ("NERC")[5] are conducting separate, independent assessments in which SPP will participate.

Section 215 of the Federal Power Act[6] requires that NERC develop mandatory and enforceable Reliability Standards, which are subject to FERC review and approval. FERC-approved Reliability Standards provide minimum requirements for reliable operation of the bulk electric system ("BES")[7]. SPP as the Balancing Authority[8] and Regional Coordinator[9] for the SPP footprint is bound by applicable Reliability Standards, and SPP is subject to FERC's enforcement jurisdiction for compliance with these Reliability Standards.

2. Did your existing emergency procedures work as intended and are there any improvements you will be implementing to deal with similar power shortages due to potential future events?

Response 2:

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3 MRO's primary responsibilities are to: ensure compliance with mandatory Reliability Standards by entities who own, operate, or use the interconnected, international BPS; conduct assessments of the grid's ability to meet electricity demand in the region; and analyze regional system events.

4 FERC is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity, which includes SPP.

5 NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel.

6 16 U.S. Code § 824o.

7 BES means the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100kV or higher.

8 A Balancing Authority integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

9 A Reliability Coordinator is responsible for the Reliable Operation of the BES and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.

SPP's existing emergency procedures[10] worked as expected during the February 2021 Weather Event. As you are aware, the February 2021 Weather Event produced extremely cold temperatures across the entire SPP service territory. This led to increased electricity usage at the same time generation resources experienced reduced ability to produce energy, as a result of a multitude of reasons. In collaboration with its member utilities and neighboring grid operators, SPP limited the storms' reliability impacts to two periods of controlled service interruptions: one on February 15, 2021, for 57 minutes to reduce regional energy use by approximately 1.5% and one on February 16, 2021, for three hours and 23 minutes to reduce regional energy use by approximately 6.5%. These actions prevented longer, uncontrolled, more widespread and costly blackouts.

Although, SPP's emergency procedures worked as intended during the February 2021 Weather Event, SPP is committed to learning from this event and identifying improvements that can better facilitate future emergency responses. SPP will implement any approved recommendations from the Comprehensive Review Steering Committee in order strengthen our emergency response procedures and to help minimize service interruptions in the future.

3. Unlike the events in Texas, as discussed in your testimony to the Energy Committees, the larger multi-state system operated by SPP and MISO appeared to be a reason the power outages in Arkansas were not as extensive.
   - Describe your preparedness and allocation process for critical energy resources during extreme events.
   - Could you elaborate on why that structure was beneficial and how the two System Operators worked together to minimize the outages in Arkansas.

Response 3(a):

During the February Weather Event, SPP entered into multiple different operating levels/alerts as defined by SPP's operating plans and the NERC Emergency Operations and Planning ("EOP") Standard 011-1. Table A gives an overview of those operating levels:

[10] SPP's emergency response plan details actions that are to be taken by SPP as the Balancing Authority and Reliability Coordinator for those applicable regional footprints. SPP's members are responsible for developing and executing their own emergency response plans applicable to the functions they perform and the parts of the transmission system under their purview.

Table A: Balancing Authority Operating Levels

BALANCING AUTHORITY (BA) OPERATING LEVELS

Levels/alerts defined by SPP operating plans

Normal Operations	SPP has enough generation to meet demand, has available reserves and does not foresee extreme or abnormal reliability threats
Weather alert	SPP expects extreme weather in its reliability coordination service territory
Resource alert	SPP's BA area expects severe weather conditions, significant outages, wind-forecast uncertainty and/or load-forecast uncertainty with potential to impact total capacity.
Conservative Operations	SPP determines the need to operate system conservatively to avoid an emergency based on weather, environmental, operational, terrorist, cyber or other events
Maximum emergency generation notification	SPP foresees the need to use emergency ranges of resources for a certain hours.

Levels defined* by NERC EOP-011-1

Energy Emergency Alert (EEA) Level 1	**All available generation resources in use** • All generation is committed, and there is concern about maintaining required reserves for BA • Non-firm wholesale energy sales curtailed.
EEA Level 2	**Load management procedures in effect** • BA is no longer able to provide its expected energy requirements and is energy deficient • Operating plan implemented, including public appeals and demand response • BA is still able to maintain minimum reserves • Market participants and other BAs notified • Transmission limitations evaluated and revised • BA makes use of all available resources
EEA Level 3	**Firm load interruption imminent or in progress** • BA is unable to meet minimum contingency reserve requirements • System & reliability limits revaluated and revised • Immediate action taken to mitigate undue risk to the Interconnection, including load shedding.

SPP 14

In anticipation of extreme winter weather and with the goal of preparing to ensure continued reliability, SPP issued early warnings including a cold weather alert on February 4th and a resource alert on February 8th. On February 9, 2021, SPP issued a conservative operations notice which remained in effect through February 20, 2021. On February 11 through February 16, 2021, SPP committed resources in the Day-Ahead Market ("DAM") using the Multi-Day Reliability Assessment ("MDRA") process for Operating Days on February 13, 2021, through February 18, 2021, to ensure resources were on notice that they would be needed during this time.

Ordinarily, SPP commits "long lead time" resources that have three to four day start times, i.e., resources that could not be committed in the Day-Ahead Reliability Unit Commitment Process (RUC)[11], through the MDRA process. However, during this conservative operations period, in the interest of reliability and in accordance with the SPP Open Access Transmission Tariff ("Tariff"), SPP committed both long-lead time and a number of non-long-lead time resources through the MDRA. This forward commitment gave resources as much advance notice as possible to procure fuel and prepare for the more extreme operating conditions forecasted to materialize

11 RUC is SPP's process to assess resource and operating reserve adequacy for the operating day, commit and/or de-commit resources as necessary, and communicate resource commitments or de-commitments to the appropriate Market Participants, as necessary.

on February 15, 2021 and expected to continue throughout the early part of that week.

On Sunday, February 14th, SPP issued an Energy Emergency Alert Level 1 and asked its member companies to begin issuance of public appeals for conservation. SPP did this in anticipation of increased electricity consumption and tightening supply concerns beginning on February 15th.

There were two periods during the February 2021 Weather Event where SPP directed its member utilities to curtail energy use to bring regional supply and demand back in balance. The first period was on February 15th at 12:04 p.m. Central time, where SPP directed our Transmission Operator ("TOP")[12] members reduce regional energy use by approximately 1.5%. This first demand interruption lasted for approximately 57 minutes before system conditions allowed SPP to restore all load. The second period was on February 16th at 6:44 a.m., where SPP directed our TOP members reduce regional energy use by approximately 6.5%. This demand interruption lasted until 10:07 a.m. In both cases, the SPP operators had declared an Energy Emergency Alert Level 3 prior to issuance of load shedding directions, signaling to our members that we did not have enough generation to serve load and maintain operating reserves and indicating that required interruptions of service might follow. Each TOP operating in the SPP Balancing Authority Area was required to curtail its energy use by a predetermined pro-rata percentage of SPP's total required regional reduction of energy use.

When TOPs are directed to curtail energy use, SPP only specifies the amount by which each member utility must decrease their load. SPP cannot, and does not, specify how the reduction of energy use should be accomplished. Rather, each TOP follows its own emergency operating plan and makes decisions regarding what residential, commercial, or industrial load to curtail. SPP directs these controlled service interruptions only as a last resort when they are necessary to prevent uncontrolled outages from occurring as a result of inaction.

Coordination and communication between SPP and other entities during an emergency event is outlined in the SPP Balancing Authority Emergency Operating Plan ("SPP BA EOP").[13] Specifically, Section 7 of the SPP BA EOP outlines coordination and communication responsibilities during Energy Emergency Alerts, which were utilized by SPP during the February 2021 Winter Event.

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12 The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.

13 SPP Balancing Authority Emergency Operating Plan: https://spp.org/documents/63143/spp%20ba%20emergency%20operating%20plan_v%207.5.pdf

Response 3(b):

SPP oversees a regional, multi-state transmission grid, with diverse generation located across its 14-state footprint in the Eastern Interconnection and strong transmission interconnections with its neighbors. As compared to transmission and generation located in just one state with limited transmission interconnections to other areas, SPP has increased ability during an emergency to rely on all generation in its entire footprint and energy transfers from neighboring areas to mitigate supply deficiencies. Similarly, SPP is more able to share its excess generation with neighboring Transmission Providers, such as MISO, to assist their efforts to operate reliably during severe weather events. During the February 2021 Weather Event, SPP received significant amounts of energy from MISO and other neighboring regions that helped minimize reliability impacts. SPP received up to approximately 6,000 MW of energy from its neighbors at certain critical times during the event.

4. As outlined in your testimony to the Energy Committee, the System Operators cooperated to provide assistance as necessary to assist the other System.
   - Were communication protocols in place prior to the February event for the System Operators to provide mutual assistance?
   - If not formal protocols, are their plans to establish more formal procedures between the System Operators in the future?

Response 4:

Yes, SPP has joint coordination/operating agreements among all of its neighboring system operators that detail communication protocols between each entity. Specifically, the following are the joint coordination agreements among SPP and its neighboring system operators: (1) Joint Operating Agreement Between MISO and SPP;[14] (2) SPP-Associated Electric Cooperative, Inc. ("AECI") Transmission Coordination Agreement;[15] (3) SPP-AECI Joint Operating Agreement;[16] (4) SPP-ERCOT Coordination Plan;[17] (5) Joint Operating Agreement between SPP and

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[14] MISO-SPP Joint Operating Agreement is required to be filed and approved by FERC. See the following: https://www.spp.org/documents/37691/2016-04-07%20spp-miso%20joa.pdf.

[15] https://www.spp.org/documents/5100/aeci%20transmission%20coordination%20agreement%2081904.pdf.

[16] https://www.spp.org/documents/8373/aeci%20spp%20joa%20final%20signed%2008-12-08.pdf.

[17] https://www.spp.org/documents/62411/ercot-spp%20coordination%20plan_20200601.pdf.

Saskatchewan Power Corporation;[18] and (6) SPP-Tennessee Valley Authority Adjacent Reliability Coordinator Coordination Agreement.[19]

Current agreements and protocols between SPP and its neighboring systems and any needed improvements are being considered in the comprehensive review currently being performed.

5. Given that communication between the System Operators is important, it is equally important to communicate with the public and affected parties of pending outages necessary to maintain the System.
   - Were the notification procedures in place at the time of the February event sufficient? What improvements to a notification process should be made?
   - When outages are necessary, who makes the determination which areas are required to shed load?
   - Are there protocols in place for determining which areas are chosen to shed load and/or consideration given to the types of facilities impacted?
   - Is there sufficient usage data to adequately determine the impact of outages in each area or on different types of infrastructure or facilities in those areas?
   - How does the end user appeal or request consideration of unique circumstances upon notification of service curtailment?

Response 5 (a):

Coordination and communication between SPP and other operating entities during an emergency event is outlined in the SPP BA EOP.[20] Specifically, Section 7 of the SPP BA EOP outlines coordination and communication responsibilities during Energy Emergency Alerts, which were effectively utilized by SPP during the February 2021 Winter Event. SPP also deployed various means of communicating with its stakeholders prior to and during the event through both written and verbal communications. Additionally, SPP held virtual meetings with public relations staff employed by member companies as well as press conferences for media.

Despite these efforts and the efforts of our member companies to communicate as effectively as we could, we understand that one of the biggest frustrations voiced

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18 https://www.spp.org/documents/36511/2015-10-01_spp-saskatchewan%20power%20corporation%20joa.pdf.

19 https://www.spp.org/documents/6157/tva%20rc%20coordination%20agreement.0506.pdf.

20 SPP BA Emergency Operating Plan: https://spp.org/documents/63143/spp%20ba%20emergency%20operating%20plan_v%207.5.pdf

by many in the general public related to a desire for more proactive and effective communications. As stated in Response 1, above, the newly formed Comprehensive Review Steering Committee is evaluating operational, financial, communications and other factors related to the events of the February 2021 Weather Event. The group will present an update on early findings at the April 27, 2021 meeting of the SPP Board of Directors and Members Committee and provide its final assessment and recommendations at the July 27, 2021 meeting of the SPP Board of Directors and Members Committee.

Response 5(b):

SPP makes the determination of which TOPs must shed load and how much load must be shed to relieve a system contingency. The TOPs then determine how to achieve the load shedding obligation placed on them by SPP in accordance with their plans. The determination of need to shed firm load only happens when all other possible means of suppling the internal SPP Balancing Authority load have been used to address an emergency within the SPP Balancing Authority Area so as not to jeopardize the reliability of the Bulk Electric System.

Response 5(c):

Yes, protocols are in place in the form of emergency response plans that are required by NERC to be developed, maintained and practiced annually. SPP's plans address its role in responding to an emergency from a regional perspective. When SPP experiences an emergency related to lack of energy needed to supply regional demand, it allocates load shedding requirements among all TOPs. When SPP experiences an emergency related to specific transmission elements, load shedding requirements are confined to those TOPs necessary to resolve the transmission-related emergency. As stated previously in Response 3(a) above, when SPP directs TOPs to curtail energy use, SPP only specifies the amount by which each TOP must decrease its load. SPP cannot, and does not, specify which end-use customers should be affected by the required reduction of energy use. Rather, each TOP follows its own emergency operating plan and makes decisions regarding what residential, commercial, or industrial load to curtail.

Response 5 (d):

SPP has the necessary data to effectuate its obligations from a regional perspective. SPP relies on the TOPs to manage their load shedding procedures including determinations of loads and customers' priorities and the infrastructure or facilities impacted. SPP does not have the level of detailed usage data to determine what impacts any load shedding event may have on TOPs' areas or distribution-level infrastructure and facilities in those areas.

Response 5(e):

As stated in Response 5(b), SPP's determination of the need to shed firm load only happens when all other possible means of suppling the internal SPP Balancing Authority load have been used to address an emergency within the SPP Balancing Authority Area so as not to jeopardize the reliability of the Bulk Electric System. Pursuant to the SPP BA EOP, participating entities within the SPP Balancing Authority Area shall have plans for how they will shed load to respond to real-time emergencies. Because firm load shed events only happen when other possible means of serving load have been used to address an emergency, it is not possible for SPP to allow participating entities to appeal or request consideration of unique circumstances to relieve them of their obligations to load shed. Any such appeals or special considerations between those participating entities and certain end-use customers would need to occur within the framework of their respective plans and protocols.

6. Are there changes that integrated system operators need to consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event?

- If so, what changes would you recommend?
- Are there constraints in place from Federal Energy Regulatory Commission or North American Electric Reliability Corporation that would prevent implementation of such changes?

Response 6(a):

At present, SPP does not have enough pump storage or battery storage in the SPP footprint that would have affected the impacts of the 2021 Weather Event on the SPP transmission system. During the 2021 Weather Event, all available generation was required (and even then, there was a two brief curtailments of energy use needed). SPP did not have the generation available, once the event was forecast, solely for storage purposes.

Electricity storage presents a potential mitigation option in addressing the unpredictability of renewable-sourced generation by allowing excess electricity production to be captured and used at a later date and time. To be effective, however, investments in such storage would need to be large-scale. Within SPP, this type of investment would be made by independent entities or vertically integrated utilities and not under the direction from SPP.

Moving forward, the usage of storage should not exclusively be considered only from a capacity perspective, but storage should also be considered from a duration of time perspective for when the storage is available. Most battery storage is being developed and accredited for 4-hour delivery of power, however, using the 2021 Weather Event as an example, 4-hour storage capacity would have been exhausted very early on during the event. For storage to make a significant impact on the grid in future weather events, SPP will need both more capacity and a longer duration of time the storage is available.

Response 6(b):

SPP does not have any recommended changes, at this time, in processes to allow for increasing generation for the purposes of holding electricity in storage in advance of a forecasted extreme weather event.

Response 6(c):

SPP is not aware of any FERC or NERC constraints that would prevent implementation of such changes.

SPP appreciates the opportunity to respond to the questions from the ERP Taskforce. Please contact me if there is further information that you may need.

Sincerely,

Lanny Nickell
Executive Vice President &
Chief Operating Officer
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223
Tel: (501) 614-3232
lnickell@spp.org

Arkansas Environmental Federation
Industries for the Environment

Plaza West – Suite 835 – 415 North McKinley Street
Little Rock, AR 72205
Phone: 501-374-0263 Fax: 501-374-8752
www.environmentark.org

Energy Resources Planning Task Force
Attn: Secretary Becky Keogh, Chair
Arkansas Department of Energy and Environment
5301 Northshore Drive
North Little Rock, AR 72118

Delivered via electronic mail to ERPTaskForce@adeq.state.ar.us

Dear Secretary Keogh,

The Arkansas Environmental Federation (AEF) is pleased at the call to participate in the Energy Resources Planning Task Force. Members of AEF range from sole proprietorships to international corporations with manufacturing facilities throughout the state. As the preeminent environmental organization serving industry in Arkansas, the AEF is pleased our Governor appointed this Task Force to review lessons learned from unprecedented winter weather and develop priorities should we face this type of emergency again.

The questions the AEF received April 12, 2021, were circulated to members for response. Member responses varied greatly depending on company size and type. Below is a compilation summary of the responses received.

1. Do Arkansas business owners or industries in Arkansas whose facilities were asked to curtail operations during the February weather event feel they were treated fairly and given adequate notice? Would you suggest any changes to prioritization of gas and electricity or communications regarding extreme weather events? If so, what changes would you make?

The consensus of the answers received by AEF demonstrate the need for earlier and more detailed notice.

2. Did the curtailment during the load-shedding event damage or reduce the effectiveness of environmental quality control equipment? What strategies could have been implemented to mitigate the impacts of curtailment and the extreme cold on control equipment?

No, the majority of responses submitted answered no. Those that did answer yes to damage believe adequate notice and minimum utility requirements are needed to mitigate equipment damage.

3. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

The unanimous answer to this question is no suggestions.

4. Describe your preparedness and allocation process for critical energy resources during extreme events.

Responses to this question mainly illustrates significant challenges to allocate energy resources during extreme events.

5. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Answers to this question were mostly split between negotiation with provider or inability to appeal or request consideration.

The answers we received represent less than 5% of AEF member companies. An extension of time to submit this questionnaire may allow companies more time to answer the questionnaire.

Sincerely,

Ava F. Roberts

Ava F. Roberts
Executive Director
Arkansas Environmental Federation

318 South Pulaski Street
Little Rock, AR 72201
501-372-4500

To: Arkansas Energy Resources Planning Task Force

Date: May 7, 2021

Via: Hand Delivery and *ERPTaskforce@adeq.state.ar.us*

Re: Hearing Testimony regarding February 2021 Winter Weather Event

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Initial Hearing Testimony

Introduction and Reservations:

The Arkansas Forest and Paper Council (AFPC) appreciates the opportunity to provide testimony to the Arkansas Energy Resources Planning Taskforce (Taskforce) on the extreme weather event of February 2021 and the significant impact the weather and resulting energy curtailments had upon the forest and paper industry in Arkansas. These comments are provided via electronic mail and hand delivery of paper copies for the convenience of the Taskforce.

The Arkansas Forest and Paper Council is a 501(c)6 trade organization representing the forest products manufacturing industry in the state of Arkansas. Our members manufacture paper and consumer products as well as building materials utilized in 95% of all business and 100% of households in the US. The industry in Arkansas has 95 facilities employing more than 19,000 direct employees with a $1.3 billion dollar payroll producing $7.6 billion dollars of product from our rich fiber basin. The economic contributions to communities and schools across the state through purchases of goods and services and taxes paid are varied and wide.

The access to reliable and affordable energy is crucial to the efficient and cost-effective operation of the forest products and manufacturing industry in Arkansas – and this is never more true than during extreme weather events. The work of the Taskforce and the related inquiries and reviews underway at the Arkansas Public Service Commission (APSC), the Federal Energy Regulatory Commission (FERC), the Regional Transmission Organizations (RTOs) and their Independent Monitors (IM), the Attorney General, among others present an opportunity for the regulators and regulated community to assess the unprecedented winter weather event of February 2021 (the WWE) and the tremendous costs and losses that resulted, and to do so with an eye towards creating an energy system that is more robust, cost-effective, and reliable to the benefit of all energy users and the communities they support.

The AFPC is uniquely situated to provide perspective on these matters given the wide impact the industry has within Arkansas. This is evident in part by the fact that its membership has facilities served by both the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO), and variously Entergy, AECC, and SWEPCO as well as receiving gas service via the Enable system and the various FERC related pipelines within Arkansas – many of which have been requested to provide testimony in the Taskforce's work.

While the AFPC provides this testimony voluntarily, it does so with several reservations. First, the Taskforce requested the AFPC respond to the following questions for the Energy Users group. Each question will be responded to in turn, repeating each question for clarity and convenience - and to the extent this issue is adequately covered by others providing testimony, the AFPC attempts to refer to that testimony. In these instances, the other testimony will be noted in the relevant question / response.

In response to each and every question and statement in response without waiver of any defense or privilege that it or its members may be entitled to claim individually or collectively, including without limit that under the Arkansas Trade Secrets Act, Arkansas Water and Air Pollution Control Act, and any others applicable to these matters. Also, the testimony is that of the AFPC, an incorporated association, and no particular statement or position should be attributed to any particular AFPC member or industry representative.

As to future proceedings of the Taskforce, the AFPC respectfully requests it be provided additional opportunity to meet with the Taskforce and other stakeholders, review the other testimonies filed with the Taskforce, and provide additional other information, if necessary.

Should the Taskforce have additional questions for the AFPC, please contact either Brent Stevenson at brent@brentstevensonassociates.com or 501-372-4500 or Kelly McQueen at kelly@mcqueen.law or (501) 580-3291.

Questions Presented

Question 1: Do Arkansas business owners or industries in Arkansas whose facilities were asked to curtail operations during the February weather event feel they were treated fairly and given adequate notice? Would you suggest any changes to the prioritization of gas and electricity or communications regarding extreme weather events? If so, what changes would you make?

Response:

Along with many others in manufacturing and industry that have expressed concerns with the February event's impacts as well as the deficiencies in the curtailment process and the resulting costs and losses, the forestry and paper industry also experienced increased costs and losses associated with the extreme weather event. Notably, all Council members experienced a curtailment, with most receiving sufficient notice from the supplier with enough time to make their individual business decision. However, the costs and losses even with adequate notice – depending on the situation – were significant, numbering in the tens of millions of dollars ($) from equipment damage, additional energy costs, production losses, increased manhours, among other costs and losses.

The AFPC refers the Taskforce to the testimony of Mr. Ted Thomas, Chairman of APSC regarding background on the winter weather event (WWE), its potential causes, and the various reviews underway related to the WWE. The APSC testimony as well as that of the Attorney General, AEEC, and numerous others provide a good overview of the winter weather impacts on downstream natural gas customers, the curtailment process and FERC managed special needs waiver process for exemption from curtailment to the extent necessary to protect a designated special need – so the AFPC will not attempt to provide an additional source of the same information.

However, the AFPC would like to highlight a number of suggestions and recommendations for the Taskforce's review, reserving the right to provide additional information and recommendations as this matter develops:

1. Other Reviews:
    a. Many of these matters appear to be under the jurisdiction of the FERC with limited opportunities for state regulation or revision. The State should participate fully in any related FERC dockets.
    b. The APSC has opened a docket for review of the WWE in which the AFPC intends to participate.
    c. The AFPC supports review of market price fluctuations.
    d. The AFPC supports the RTO review processes currently underway.

2. Rate / Tariff Design:
    a. APSC and state utilities should design interruptible tariffs reflective of cost-to-serve, with appropriate price signals, and compensation for the value interruptible customers provide the system.
    b. Promotion of progressive interruptible tariffs, with appropriate compensation and price signals, to encourage more emergency demand response participation should be considered.
3. Reserve Margin: each RTO should have a reliable, reasonable, and dispatchable reserve margin with sufficient capacity to meet swing loads and peak capacity demands.

4. Affidavits of Special Need:
    a. The definition of special needs should be expanded to provide sufficient protection for human health and plant protection,
    b. Education of availability of Affidavits and curtailment process generally should be required of distribution and transmission service companies.
    c. Timing of filing of Affidavits should be flexible enough for submittal after beginning of curtailment.

5. Federal-Local Partnership: to the extent possible, the interstate FERC mandated pipeline rules and those governing the local distribution should not conflict.

6. Communications: Explore all means to facilitate more effective communications in extreme weather events or other energy disruptions including review of additional lines and modes of communication between providers and users with specified requirements for updates related to price / supply / other necessary metrics to be developed.

Question 2: Did the curtailment during the load-shedding event damage or reduce the effectiveness of environmental quality control equipment? What strategies could have been implemented to mitigate the impacts of curtailment and the extreme cold on control equipment?

Response:

Across industry of all sorts, extreme weather events and any energy disruptions may have an impact on the effectiveness and even operation of pollution control equipment. The Environmental Protection Agency (EPA) for federal programs and the Arkansas Division of Environmental Quality (ADEQ), as implementing the Arkansas Pollution Control and Ecology Commission (APC&EC) regulations and related federal EPA requirements has procedures for how to proceed in the event this occurs.

<u>Question 3</u>: Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

<u>Response</u>:

The AFPC does not have information on which entities currently have been requested to provide testimony. Based upon the Executive Order, the AFPC respectfully suggests that testimony from the Attorney General, ENABLE Midstream Partners, and other manufacturing related entities may provide additional information benefiting the Taskforce's review and report.

<u>Question 4</u>: Describe your preparedness and allocation process for critical energy resources during extreme events.

<u>Response:</u>

As an association, the AFPC does not have preparedness or allocation processes for critical resources during extreme events. Speaking generally, facilities within the industry routinely have standard operating procedures in place for inclement weather conditions and implement these procedures during such occurrences.

<u>Question 5</u>: Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

<u>Response:</u>

Please see Response to Question 4.

To: Arkansas Energy Resources Planning Task Force
From: Tinsley & Youngdahl, LLC, Attorneys for AEEC and AGC
Date: May 7, 2021
Via: Email to ERPTaskforce@adeq.state.ar.us
Re: Hearing Testimony on February 2021 Winter Weather Event

Initial Hearing Testimony

Introduction and Reservations:

Arkansas Electric Energy Consumers, Inc. (AEEC) and Arkansas Gas Consumers, Inc. (AGC) appreciate the opportunity to provide testimony to the Arkansas Energy Resources Planning Task Force (Task Force) on the extreme weather event of February 2021 and the significant impact the weather and resulting energy curtailments had upon industrial and agricultural business concerns in Arkansas. AEEC is an incorporated trade association that represents the interests of several large users of electricity in Arkansas, and AGC is an incorporated trade association that represents the interests of several large users of natural gas in Arkansas. The access to reliable and low-cost energy is crucial to the efficient and cost-effective operation of large businesses in Arkansas – and this is never more true than during extreme weather events. The work of the Task Force, together with related inquiries and reviews underway at the Federal Energy Regulatory Commission (FERC), the Arkansas Public Service Commission (APSC), Regional Transmission Organizations (RTOs) and their Independent Monitors (IM), and the

Attorney General (among others), present an opportunity for regulators and regulated community to assess wisely the unprecedented winter weather event of February 2021 (the WWE) and the tremendous costs and losses that resulted, and to do so with an eye towards creating an energy system that is more robust, cost-effective, and reliable to the benefit of all energy users and the communities they support. AEEC and AGC members primarily have facilities served by the Midcontinent Independent System Operator (MISO) and its member Entergy Arkansas, LLC, as well as members receiving natural gas service via the Enable system and the various FERC related pipelines within Arkansas – many of which have been requested to provide testimony in the Task Force's work.

While AEEC and AGC provide this testimony voluntarily, they do so with several reservations. First, AEEC and AGC are responding to the following questions asked of the Energy Users group. Each and every statement in response should not be construed as a waiver of any defense or privilege that it or its members may be entitled to claim individually or collectively, including (without limitation) any defense or privilege arising under the Arkansas Trade Secrets Act, Arkansas Water and Air Pollution Control Act, and any other laws or regulations applicable to these matters. Also, the testimony is that of AEEC and AGC, two incorporated trade associations, and no particular statement or position should be attributed to any particular AEEC or AGC member or industry representative. As to future proceedings of the Task Force, AEEC and AGC respectfully request that they be provided additional opportunity to meet with the Task Force and other stakeholders, review the other testimonies filed with the Task Force, and provide additional information, if necessary. Should the Task Force have additional questions for AEEC or AGC, please contact Steven Cousins (stevencousins@outlook.com), Jordan Tinsley of Tinsley & Youngdahl, PLLC (Jordan@TYattorney.com).

AEEC and AGC Responses to ERPTF Questions to Energy Users:

1. Do Arkansas business owners or industries in Arkansas whose facilities were asked to curtail operations during the February weather event feel they were treated fairly and given adequate notice? Would you suggest any changes to the prioritization of gas and electricity or communications regarding extreme weather events? If so, what changes would you make?

While AEEC is an incorporated trade association that represents the interests of several large users of electricity in Arkansas, it cannot reveal any customer-specific information in response to these questions. AEEC can only speak generally about how the winter events impacted large customers, and what best practices should be. Many industrial and agricultural customers take electric service on interruptible tariffs, which means they can be subject to curtailment in the event that the utility's peak load has exceeded the available capacity. In exchange for their agreement to be interruptible, those customers receive a discount on rates. February's events amply demonstrated that the existence and availability of interruptible customers provides substantial benefits to the utility, its grid, and other ratepayers. To the extent that the state's electric utilities largely complied with the notice provisions contained in their respective interruptible tariffs during February's events, it is difficult to say that the electric utilities did not provide adequate notice of the interruptions that occurred. Regulators should take note of the effectiveness of those interruptible tariffs, however, and think twice before making any changes that could impair the economics of interruptible tariffs for large customers. To the extent they are not already doing so, the APSC and state utilities should design interruptible tariffs reflective of cost-to-serve, with appropriate price signals, and provide sufficient compensation for the value interruptible customers provide the system, and promote progressive interruptible tariffs, with appropriate compensation and price signals, to encourage more emergency demand response participation.

Further, large customers' operations are very sensitive to fuel and purchased power costs, which are passed through to all customers. Therefore, two communications issues should be prioritized: First, to the extent a customer is to be curtailed, the utility should provide notice as soon in advance as possible, to enable the business to change its operations as necessary to minimize the disruption and additional costs to its operations; second, any significant increases in energy costs need to be communicated to the business as soon as possible, so that the business can determine whether it is in its best interest to reduce or shut down operations (except the minimum necessary to keep its equipment from freezing) in view of these price spikes.

Similarly, while AGC is an incorporated trade association that represents the interests of several large users of natural gas in Arkansas, it cannot reveal any customer-specific information in response to these questions, and can only speak generally about how the winter events impacted large customers, and what best practices should be. Many large customers are gas transportation customers, which means they purchase gas directly from upstream suppliers, which they then transport through the gas pipelines, either through contracts at a fixed rate, or through contracts whose rate may fluctuate with spot market prices. The gas supply market also features managers and schedulers in addition to the pipelines and end users. In cases where there are reduced gas supplies in winter, some pipelines may reduce load by reducing the flow of gas to a transportation customer to the minimum amount necessary to keep its equipment from freezing, provided that the customer has a special needs and/or plant protection affidavit on file with the pipeline. When a customer does not have such an affidavit on file, that customer bears the risk of either (a) being completely shut off from gas, potentially causing damage to equipment due to the extreme cold; or (b) incurring substantial penalties for burning gas during a curtailment event. Thus, it is important for market participants to educate end users about the need to have these affidavits on file, and when a major winter event is approaching, to give the customers adequate and timely reminders that these affidavits need to be executed and filed. Further, as is the case for electricity customers, significant increases in energy costs need to be timely communicated to the business, so that the business (especially one whose price fluctuates with the market) can determine whether it is in its best interest to reduce or shut down operations (except the minimum necessary to keep its equipment from freezing) in view of these price spikes.

The feedback that AEEC and AGC have received from their members after February's events suggests that many large industrial and agricultural customers were not aware of the requirement that they maintain plant protection and/or special needs affidavits on file with the gas pipeline through which they transport gas, although some customers were aware of that requirement. In light of that, the pipeline companies and other market participants should do more to educate customers about those requirements well in advance of events like this. In many cases, customers did not become aware of that requirement until it was too late to file the affidavit, insofar as the pipeline company requires it to be filed before the curtailment event. Moreover, many of the large end user companies have personnel managing their gas and electricity supply who also have substantial other responsibilities. Providing those individuals with short notice within which to perform certain tasks is typically not effective, insofar as the personnel are typically involved in lots of activity to prepare for an event of this nature, and their attention is necessarily divided. Thus, the pipeline companies should also consider allowing customers to file those plant protection/special needs affidavits for a period of time after a curtailment begins. Moreover, regulators should consider requiring some market participants (like suppliers, managers and schedulers) to provide end users with regular updates regarding spot market gas prices or even the price of kWh in the RTO day-ahead markets.

2. Did the curtailment during the load-shedding event damage or reduce the effectiveness of environmental quality control equipment?

What strategies could have been implemented to mitigate the impacts of curtailment and the extreme cold on control equipment?

Again, neither AEEC nor AGC can reveal any customer-specific information in response to these questions. We can point out, however, that environmental quality control equipment, like any other equipment in a factory or agricultural operation, can be damaged by extreme cold. Therefore, the best practices discussed in response to Question no. 1 which would minimize the possibility of plants being totally without heat and their equipment being damaged as a consequence also apply to minimize the possibility of damage to environmental quality control equipment.

3. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

As noted above, we have answered these questions on behalf of AGC, even though the Executive Order only included AEEC. Other natural gas consumers besides AGC could also provide potentially useful information to the Task Force.

Further, AEEC and AGC could provide some suggestions to the Task Force in response to questions that were posed to other groups. For example:

- **ELECTRIC UTILITIES Question No. 1:**
    - The prices charged at wholesale in the spot energy market are regulated by the Federal Energy Regulatory Commission (FERC). The State should, however, participate fully in any related FERC dockets and/or file a

complaint with FERC regarding these matters. Arkansas can push FERC to investigate possible manipulation of some prices in MISO and SPP during the February events, to assure that Arkansas End Users receive relief from higher energy prices that resulted from market manipulation.

- **ELECTRIC UTILITIES Question No. 3:**
    - AEEC maintains that one of the best hedges against energy price spikes is a diverse mix of electric generation capacity, so that one event, be it weather-related or otherwise, does not have an extreme impact on energy prices. This needs to be considered in planning future generation, and in decisions about plant retirements.
- **ELECTRIC UTILITIES Question No. 4:**
    - AEEC agrees that storage solutions for electricity should be explored, especially when coupled with solar energy. It is important in exploring these solutions that costs, as well as benefits, be included in any analysis, however.
- **NATURAL GAS PRODUCERS AND SUPPLIERS Question No. 1:**
    - AGC contends that encouraging and investing in pipeline diversity will significantly reduce the risk that future winter-weather events could result in gas shortages and curtailments; the more sources of gas supply, both in terms of geography and gas suppliers, the less chance that one event will detrimentally impact supply.

4. Describe your preparedness and allocation process for critical energy resources during extreme events.

AEEC and AGC incorporate the response to Question no. 1 above for reference. As noted in that response, they cannot reveal any customer-specific information in response to these questions.

5. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

As for Question no. 4, AEEC and AGC incorporate the response to Question no. 1 above for reference. As noted in that response, they cannot reveal any customer-specific information in response to these questions.

Quattlebaum, Grooms & Tull
A PROFESSIONAL LIMITED LIABILITY COMPANY
111 Center Street
Suite 1900
Little Rock, Arkansas 72201
(501) 379-1700

Michael B. Heister
mheister@qgtlaw.com
Licensed in Arkansas and the District of Columbia

Direct Dial
501-379-1777
Direct Fax
501-379-1701

April 30, 2021

***Via Email:* [*Troy.Deal@adeq.state.ar.us*](mailto:Troy.Deal@adeq.state.ar.us)**

Secretary Becky W. Keough
Cabinet Secretary, Arkansas Energy & Environment
Chair, Energy Resources Planning Task Force

Secretary Keogh:

I was honored to receive your April 9, 2021, request on behalf of Governor Asa Hutchinson's Energy Resources Planning Task Force ("the Task Force") to submit written comments in response to the Testimony Questions sent to "Energy Users" and "Electric Utilities." My firm, Quattlebaum, Grooms & Tull, PLLC, is privileged to represent clients in both groups. To be clear, my responses today are my own based on my experience advising clients during the February winter storms and in the weeks that followed, as well as my personal assessment of publicly-available statements in the media, journals, and other trade publications issued in the wake of the February storms. I hope the comments below are of some assistance to the Task Force as it performs its important work.

ENERGY USERS & ELECTRIC UTILITIES

From my perspective, the State of Arkansas's executive branch performed admirably during the February winter storms. State employees from your office, the Arkansas Department of Energy and Environment, Department of Environmental Quality ("DEQ") as well as the Arkansas Public Service Commission ("APSC") and other agencies were very responsive to energy and environmental-related concerns during the February winter storms. Arkansans should be proud of their willingness to work hard and think creatively to ensure the public was protected despite the adverse weather conditions.

The storms' consequences were severe from both a human and economic perspective. Arkansas is fortunate that the severe weather did not last longer here and that it was not even colder than it was. This experience has made it clear that it would be helpful if Arkansas's key regulators were given more legal tools to coordinate on resource distribution or even intervene directly in the future if a temporary emergency implicating public safety requires it. This would require new statutory authority. As the Task Force considers what new authority should be recommended, it may want to consider the following:

- DEQ has reliable, time-tested mechanisms for reporting environmental emergencies and for providing notice when pollution control equipment fails. These work well on a day-to-day basis. However, Arkansas's February experience as well as lessons learned from disasters in Louisiana, Texas, and other states suggests that such systems are not designed for or intended to address multiple, simultaneous emergencies. DEQ could be given the authority, when authorized by the Governor and consistent with federal law, to expand reporting mechanisms temporarily to include resources such as Twitter, Facebook, or other electronic means of communication that DEQ determines, to enable those who are perhaps without power and/or are stranded to provide legally valid notice to the agency of emergency situations.
- Regarding pollution control equipment, it is important not to try to "fight the last war." The next major emergency might just as easily be a long-predicted New Madrid fault earthquake or regional power outage of extended duration as opposed to a sustained deep freeze. Although reporting requirements under federal law such as the Emergency Planning and Community Right-to-Know Act ("EPCRA"), 42 U.S.C. § 11001 *et seq.*, already exist, it might be helpful for DEQ to review whether its existing documentation is organized in a manner such that DEQ can quickly identify which pollution control equipment it regulates in a region of the state, if any, might pose an immediate threat to human health in the event of a catastrophic failure.

- DEQ and APSC should consider what advance authority they would need the Governor to have to enable either agency, as appropriate, to intervene, perhaps by invitation and perhaps not, when a critical resource, e.g., natural gas, needs to be rationed and there is a dispute among private entities regarding how best to do so in a manner that best serves the public. Indeed, a distributor might prefer to have state assistance in making such determinations to relieve the distributor of competing, irreconcilable contractual obligations.
- The Task Force may want to give separate consideration to whether an electronic system could be used to remind relevant parties of the ability the State has to assist with any new authorities that might arise from the Task Force's work. A sophisticated company addressing a myriad of problems at once, as always occurs during an emergency, is unlikely to be familiar with the different authorities possessed by each state in which the company operates and might not have immediate access to someone who is.
- The Task Force's recommendations that are adopted could be implemented as rules to the extent statutory authority already exists for the proposed action. Where new statutory authority is required, draft rules could be prepared by the Task Force in advance, to ensure that the statutory authority provided is adequate to implement the Task Force's objectives. Of course, such draft rules would then have to be properly noticed and subject to comment once the necessary statutory authority was provided.
- The Task Force should consider whether the State could provide additional funding to key agencies to enable them to offer voluntary stress testing to facilities. This could include environmental and energy-related issues as well as logistical and transportation infrastructure concerns. Many companies' personnel have experience working in a particular geographic region, and their emergency experience is based on the types of emergencies they and their colleagues typically experience. The State should consider whether it could help interested facilities identify in advance low-probability/high-impact events that are outside the experience of most day-to-day operators and that might have unpredictable consequences for a particular facility. It is essential that such a program be voluntary to ensure it receives adequate support.

Governor Hutchinson has presented the Task Force with a critical job, and I appreciate the Task Force diligent efforts in carrying it out. I hope that these comments are of some use to the Task Force. Of course, I would be pleased to elaborate on any of this if it would be of any assistance to the Task Force.

Sincerely,

QUATTLEBAUM, GROOMS & TULL PLLC

Michael B. Heister

MBH:lsw

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE

RESPONSE OF BLACK HILLS ENERGY ARKANSAS, INC. TO QUESTIONS FROM THE TASK FORCE

On April 13, 2021, Black Hills Energy Arkansas, Inc. ("BHEA") received questions from the Task Force and respectfully submits the following responses.

Q1a. IT APPEARED FROM THE ENERGY COMMITTEE TESTIMONY THAT THE SHORTAGE OF NATURAL GAS COMING INTO ARKANSAS CONTRIBUTED SIGNIFICANTLY TO THE POWER SHORTAGE IN THE STATE DURING THE FEBRUARY WINTER EVENT. COULD YOU ELABORATE ON THE REASONS FOR THAT SHORTAGE AND WHAT IMPACTED THE NATURAL GAS SUPPLY?

A. BHEA contracts with gas marketers for gas supply and with interstate pipeline companies to have that supply transported and delivered to its local distribution systems in Arkansas. During the February winter event, BHEA received force majeure notices from multiple gas suppliers stating that they would be unable to deliver contracted volumes due to freezing of natural gas wells and related facilities. BHEA also received notices from multiple interstate pipeline companies requiring it reduce volumes taken from the pipelines due to "the unprecedented level of natural gas production freeze-offs and other supply disruptions," and "severe cold weather conditions and receipt supply shortfalls." The pipeline notices also mentioned insufficient supply delivered from upstream interconnect locations, upstream suppliers that are unable to meet their scheduled deliveries, and failure of compressor facilities.

The Energy Information Administration ("EIA") reported that U.S. dry natural gas production fell to as low as 69.7 billion cubic feet per day (Bcf/d) on February 17, a decline of 21%, or down nearly 18.9 Bcf/d from the week ending February 13. Also according to EIA, natural gas production in Texas fell almost 45% from 21.3 Bcf/d during the week ending February 13 to a daily low of 11.8 Bcf/d on Wednesday, February 17. EIA further reported that the decline in natural gas production was mostly a result of freeze-offs, which occur when water and other liquids in the raw natural gas stream freeze at the wellhead or in natural gas gathering lines near production facilities. At the same time natural gas demand for both direct end use across BHEA's system and power generation across much of the nation was very high. Demand for natural gas on BHEA's system went to record highs as BHEA exceeded its previous peak day demand by more than 10%.

Q1b. NATURAL GAS BEING USED BOTH FOR HOME HEATING AND POWER GENERATION CONTRIBUTED TO THE INCREASED DEMAND. ARE THERE MITIGATION STRATEGIES WHICH COULD BE EMPLOYED TO ENSURE ARKANSAS HAS ADEQUATE SUPPLIES OF NATURAL GAS DURING FUTURE WEATHER EVENTS? ARE THERE EVENTS OR SCENARIOS, OTHER THAN WEATHER EVENTS, WHICH COULD IMPACT THE SUPPLY OF NATURAL GAS IN ARKANSAS?

A. Presumably, supply would have more closely met demand if freeze offs of natural gas wells and related facilities had not occurred. Therefore, more effective winterization of those facilities would be a logical step. However, since the freeze off related supply disruptions seemed to occur mostly in other states, it may be difficult for Arkansas to directly address that situation.

On the natural gas supply side, continued supportive policy and a regulatory environment that encourages natural gas production, storage and pipeline development is important to ensure adequate supply of natural gas during future weather events. For example, the APSC's approval of BHEA's acquisition of additional storage facilities in 2015 provided BHEA with storage facilities that were critical to meeting supply deliverability during the weather event.

On the natural gas demand side, energy efficiency and weatherization programs can continue to play an important role, including programs that optimize the efficiency of natural gas usage at both the power plant and the consumer burner tip including technologies such as high efficiency natural gas heat pumps, furnaces, tankless water heaters, and smart thermostats.

There are events or scenarios, other than weather events, which could impact the supply of natural gas in Arkansas. These include natural disasters such as earthquakes that cause pipeline ruptures, pipeline damage caused by insufficient excavation practices, and acts of terrorism. Energy policies that increase the cost of exploring for, producing, and delivering natural gas or restrict activities related to exploring for, producing and delivering natural gas such as leasing, drilling, fracking, etc. could also impact the supply of natural gas in Arkansas over the longer term.

Q1c. GIVEN THAT THE SUPPLY OF NATURAL GAS WAS SIGNIFICANTLY AFFECTED DURING THE FEBRUARY WINTER EVENT AND RESULTED IN CURTAILED SUPPLY TO CUSTOMERS, WHAT ARE THE PROTOCOLS TO

DETERMINE WHICH CUSTOMERS WILL BE AFFECTED FOR THE REMAINDER OF THE YEAR?

A. In Arkansas natural gas customers may be curtailed by either the natural gas utility delivering gas to the customer or by the interstate pipeline delivering the customer's gas to the natural gas utility or directly to the customer. Both situations occurred during the February winter event. When it becomes necessary for BHEA to curtail its customers BHEA determines the customers to be curtailed in accordance with its curtailment policy. BHEA's curtailment policy is included in its tariffs filed with and approved by the Arkansas Public Service Commission ("APSC") as Policy Schedule 4.1. A copy of BHEA's curtailment policy is attached. Curtailments may be caused by pipeline capacity constraints on BHEA's pipeline system or by gas supply or upstream pipeline capacity constraints. The curtailment procedure is different depending on the cause of the curtailment but in either scenario, human needs customers are exempt from curtailment. BHEA's curtailment policy defines human needs as: "hospitals, housing, greenhouses, poultry farms, public and private schools (except colleges and/or universities having central boiler plants for heating and an alternative fuel source)."

Curtailments may be limited to specific areas rather than system wide depending on where the gas supply or capacity constraint occurs. For example, if BHEA has a gas supply or capacity constraint in the Bentonville area, it would probably not help to curtail customers in the Clarksville area. The curtailment policy establishes an order of curtailment based on the customer's gas consumption with customers having greater consumption being curtailed first. When BHEA curtails a customer the curtailment policy provides that BHEA will, to the extent possible, allow a minimum volume of gas consumption for heating necessary to avoid physical damage to the customer's facility.

BHEA provides only transportation service for some large business customers. These transportation customers buy their own gas supply from gas marketers or producers and have it delivered to BHEA's pipeline system through interstate pipelines. They pay a transportation rate to BHEA to have the gas delivered to their business locations. When there are gas supply or capacity constraints on the interstate pipeline systems delivering gas to BHEA, these customers may be curtailed by the interstate pipeline. This actually happened on the morning of February 16 when one interstate pipeline delivering gas to BHEA's system on behalf of multiple BHEA large business customers issued an Emergency Response Operational Flow Order requiring all customers who had not submitted a human needs affidavit to reduce their deliveries from the pipeline to zero within two hours. This order affected multiple BHEA transportation customers.

Q1d. WHAT ADDITIONAL STRATEGIES, REGULATIONS, PROTOCOLS, INCENTIVES AND/OR POLICES SHOULD BE DEVELOPED BY INDUSTRY OR GOVERNMENT TO ENSURE ARKANSAS HAS AN ADEQUATE NATURAL GAS SUPPLY?

A. At the same time that Arkansas desires affordable, abundant natural gas supplies with high reliability, the federal government and some state and local governments are adopting policies that could restrict the supply of natural gas and increase the cost of producing natural gas and building natural gas infrastructure. The government of Arkansas should work with its congressional delegation and also through the court system when appropriate to encourage balanced federal energy policy that fully develops all of America's energy fuel sources, technologies, and energy infrastructure in an economical, sustainable, and reliable manner.

It is also important for Arkansas to continue to ensure supportive policy and a regulatory environment that encourages natural gas production, storage, and pipeline development. BHEA will continue to assess and evaluate prudent natural gas utility investments that support increased supply reliability and will work with the APSC in addressing timely cost recovery of such investments. Additionally, providing support for potential investment in renewable natural gas and hydrogen projects can also have an important role in ensuring Arkansas has an adequate natural gas supply.

Additionally, when electric utilities implement rolling blackouts during cold weather events, there should be coordination with gas utilities to the extent possible. Blackouts initially provide some relief to the natural gas system as gas appliances that require electricity go offline. However, when the blackout ends there is a sudden surge in natural gas demand as 100% of those appliances come back on at the same time. Sudden surges in gas demand during already peak conditions can cause pressure drops on the gas utility system that may result in loss of service to segments of the system.

Q2. WHAT INCENTIVES COULD THE STATE PROVIDE TO HELP ENSURE AN ADEQUATE SUPPLY OF NATURAL GAS DURING EXTREME WEATHER EVENTS?

A**.** See response to Q1d above.

Q3. WHAT WOULD BE YOUR RECOMMENDATIONS TO ENSURE AN ADEQUATE SUPPLY OF NATURAL GAS FOR THE STATE DURING EXTREME WEATHER EVENTS OR OTHER TYPES OF SUPPLY DISRUPTIONS?

A. See responses to Q1d above.

Q4. DESCRIBE YOUR PREPAREDNESS AND ALLOCATION PROCESS FOR CRITICAL ENERGY RESOURCES DURING EXTREME EVENTS.

A. Weather related curtailments on BHEA's system are very rare. Prior to the February winter event, BHEA's last weather-related curtailment occurred approximately 25 years ago. BHEA designs its pipeline system and gas supply portfolio around a Design Peak Day which represents the coldest weather conditions on its system within the last several decades. Using multiple forecasting models, the pipeline system, underground storage and gas supply portfolio is designed to provide adequate gas supply and capacity under conditions replicating the design peak day at the peak hour of that day. Pursuant to the APSC Natural Gas Procurement Plan Rules ("Rules"), BHEA annually files a Gas Supply and Capacity Plan with the APSC which is reviewed by the APSC Staff. Pursuant to the Rules, BHEA's plan is designed around the principal that it should produce a diversified gas supply portfolio designed to yield an appropriate balance of reliability, reduced volatility, and reasonable price.

When extreme winter weather is forecasted, BHEA strives to operate its pipeline system near maximum allowable pressures in preparation for stronger demand. BHEA also continuously monitors its gas supply and key infrastructure while also encouraging customers to conserve energy. If the forecast is for very severe conditions BHEA may also advise large customers of the potential for curtailments and ask for voluntary volume reductions.

When a curtailment event actually occurs, customers are curtailed in accordance with BHEA's curtailment policy. See response to Q1c above. During a curtailment event the objective will be to reduce demand to the extent required to maintain service to residential and other human needs customers.

Q5. DESCRIBE YOUR NOTIFICATION PROCESS TO END USERS WHEN CURTAILING SERVICES. HOW DOES THE END USER APPEAL OR REQUEST CONSIDERATION OF UNIQUE CIRCUMSTANCES UPON NOTIFICATION?

A. When curtailment of a BHEA customer is necessary, a representative of BHEA will call the customer to notify them of the curtailment. If a customer wants to request consideration of unique circumstances, the customer would make such a request at that time. However, when a curtailment situation arises there is little room for flexibility due to the urgency of maintaining service to residential and other human needs customers. When a curtailment seems imminent but potentially avoidable, BHEA will call curtailable customers in the affected area and ask for voluntary volume reductions.

Original Sheet No. 1 of 3 Replacing Black Hills Energy Arkansas, Inc. d/b/a/ Black Hills Energy (Name of Company) Kind of Service: Natural Gas Class of Service: All Policy Schedule No.: 4.1 Title: Curtailment Policy – (PS-1)	PSC File Mark Only

CURTAILMENT POLICY-(PS-1)

Whenever the supply of natural gas, upstream pipeline capacity or the capacity of the Company's transmission or distribution system in any area is less than the amount required to meet the needs of all customers in that area, the Company shall have the right to curtail the use of natural gas by its customers in the area where the shortage exists. The Company shall not be liable for any loss or damage that may be sustained by any customer by reason of curtailment. If continuity of energy supply is required by any customer, the customer should install and maintain whatever back-up energy system that may be needed.

The order for curtailment of customers shall be based upon the annual consumption during current or preceding year. If there is not sufficient consumption history to establish the annual consumption for prioritizing curtailment, the Company, in its sole discretion reasonably exercised, will estimate the annual consumption. Those customers having the highest annual consumption in the area where the shortage exists shall be subject to curtailment first. To further define curtailment, the following shall be the applicable order of curtailment:

Curtailment Due To Gas Supply and Upstream Pipeline Capacity:
If the reason for the curtailment is due to a shortage of gas supply and/or upstream pipeline capacity, curtailments shall be made as follows:

System Supply Customers:

1. Class 1 – Curtailment: Non-exempt system supply customers (see Exemption below) whose annual consumption is in excess of 300,000 Ccf shall be first to curtail.

2. Class 2 – Curtailment: Non-exempt system supply customers (see Exemption below) whose annual consumption is in excess of 50,000 Ccf but less than 300,001 Ccf shall be curtailed after Class 1 curtailments.

3. Class 3 – Curtailment: All other non-exempt system supply customers (see Exemption below).

4. Class 4 – Curtailment: All remaining system supply customers.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 2 of 3 Replacing Black Hills Energy Arkansas, Inc. d/b/a/ Black Hills Energy (Name of Company) Kind of Service: Natural Gas Class of Service: All Policy Schedule No.: 4.1 Title: Curtailment Policy – (PS-1)	PSC File Mark Only

Transportation Customers:

Transportation customers whose supply of natural gas is delivered to the Company's transmission or distribution system shall not be subject to curtailment due to a shortage of gas supply and/or upstream pipeline capacity.

Curtailment Due to Company Transmission and/or Distribution Capacity Constraints:
If the reason for the need to curtail is due to capacity constraints on the Company's own transmission or distribution system, curtailment shall be made in the following order:

1. Class 1 – Curtailment: Non-exempt system supply and transportation customers (see Exemption below) whose annual consumption is in excess of 300,000 Ccf shall be first to curtail.

2. Class 2 – Curtailment: Non-exempt system supply customers and transportation customers (see Exemption below) whose annual consumption is in excess of 50,000 Ccf but less than 300,001 Ccf shall be curtailed after Class 1 curtailments.

3. Class 3 – Curtailment: All other non-exempt system supply and transportation customers.

4. Class 4 – Curtailment: All remaining system supply and transportation customers.

Exemption:
Human needs customers shall be exempt from curtailment. Human needs include hospitals, housing, greenhouses, poultry farms, public and private schools (except colleges and/or universities having central boiler plants for heating and an alternative fuel source). However human needs customers in the Class 1 and Class 2 curtailment category that have a back-up energy system installed that can replace natural gas as the energy source for all of the facility's human needs requirements and provide the Company an affidavit stating such and releasing the Company from any liability shall have the right to request that it not be considered as an exempt customer and therefore be subject to curtailment.

THIS SPACE FOR PSC USE

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 3 of 3 Replacing Black Hills Energy Arkansas, Inc. d/b/a/ Black Hills Energy (Name of Company) Kind of Service: Natural Gas Class of Service: All Policy Schedule No.: 4.1 Title: Curtailment Policy – (PS-1)	PSC File Mark Only

Penalty for Non-Interruption:

To the extent possible, the Company shall allow a minimum of consumption during periods of curtailment, for such heating necessary to avoid physical damage. All other gas usage must be discontinued during specified periods of curtailment.

If a customer fails to curtail his use of natural gas hereunder when required to do so by the Company, gas service may be discontinued and/or the customer will be charged for all gas consumed during such period of curtailment at a rate of $10.00 per Mcf. Failure to curtail is when gas usage during the period of curtailment exceeds minimum heating requirements as described herein.

THIS SPACE FOR PSC USE

ENERGY RESOURCES PLANNING TASK FORCE

TESTIMONY QUESTIONS

Please send your responses to ERPTaskForce@arkansas.gov on or before April 30, 2021.

NATURAL GAS PRODUCERS AND SUPPLIERS

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

   - It appeared from the Energy Committee testimony that the shortage of natural gas coming into Arkansas contributed significantly to the power shortage in the State during the February winter event. Could you elaborate on the reasons for that shortage and what impacted the natural gas supply?

Response of CenterPoint Arkansas: CenterPoint Arkansas is a natural gas distribution company that serves natural gas to its end-use customers. CenterPoint Arkansas does not serve any power generators; therefore, it has no direct knowledge of what caused the electric power shortages in the state. CenterPoint was able to obtain all the necessary supply required to fully supply its obligation to its sales customers and did not experience any inability to meet its supply obligation.

Delivering natural gas to customers has two components—commodity gas supply and transportation. CenterPoint Arkansas has two general types of customers--sales customers and transportation customers. To serve sales customers, CenterPoint Arkansas purchases gas, arranges interstate pipeline transportation and delivery of the gas into its distribution system, and distributes that gas through its system to its customers' homes and businesses. Transportation customers are generally large commercial customers that work with third party suppliers to purchase gas and deliver it through the interstate pipelines to CenterPoint Arkansas's distribution system for final delivery to the customer. Both the Company and transportation customers are themselves customers of interstate pipelines, as transportation customers independently contract for this service, instead of using CenterPoint Arkansas's all-in-one sales services.

Although prices were extraordinarily high during the February winter event, CenterPoint Arkansas was able to obtain all the necessary gas supply required in order to fully supply its obligations to its sales customers and to transport it into its distribution system for delivery to the end-use customers. Enable Gas Transmission is an interstate pipeline system that is CenterPoint's primary source for deliveries of gas into its distribution system. Given limits on its system during the February winter event, Enable announced that it would only deliver gas on behalf of customers who supplied human needs, and only up to their stated human needs. With that announcement, transportation customers' gas supplies that were not for human needs ceased to be delivered into the Company's distribution system. After this occurred, the Company was only able to receive gas purchased for its sales customers and the human needs of transportation customers. Any further gas consumed by non-human needs transportation customers would have reduced the amount of gas available to sales customers. At that point, the Company invoked its curtailment tariff[1] on file with and approved by the Arkansas Public Service Commission for its non-human needs transportation customers, and ceased to allow these customers to use any more gas from its distribution system.

- Natural gas being used both for home heating and power generation contributed to the increased demand. Are there mitigation strategies which could be employed to ensure Arkansas has adequate supplies of natural gas during future weather events? Are there events or scenarios, other than weather events, which could impact the supply of natural gas in Arkansas?

Response of CenterPoint Arkansas: As a natural gas distribution company that does not supply any power generators, CenterPoint Arkansas has no direct knowledge of what caused the electric power shortages in the state. Although prices were high, the Company was able to obtain all the necessary gas supply required to fully supply its obligations to its sales customers and did not experience any inability to meet its supply obligations.

The Company was able to maintain deliveries into its distribution systems because it pays interstate pipelines for "firm" service, which means its gas shipments have the highest possible priority. Firm transportation is one way to ensure that supplies are available during periods of high capacity utilization. There are a number of other events or scenarios that could impact the supply of natural gas in Arkansas, including damage to underground facilities or other operational issues.

- Given that the supply of natural gas was significantly affected during the February winter event and resulted in curtailed supply to customers, what are the protocols to determine which customers will be affected for the remainder of the year?

Response of CenterPoint Arkansas: Curtailment is conducted pursuant to the Company's tariff on file with and approved by the Arkansas Public Service Commission.

- What additional strategies, regulations, protocols, incentives and/or polices should be developed by industry or government to ensure that Arkansas has an adequate natural gas supply?

Response of CenterPoint Arkansas: As mentioned above, CenterPoint was able to obtain all the necessary gas supply required to fully supply its obligations to its sales customers and did not experience any supply failures. Nevertheless, there were market areas across America that did not see as much impact as the mid-continent states. Diversity of supply locations is critical during times like February and will create more reliability and supply options. Additional local supplies or local storage capability would reduce Arkansas's dependence on out-of-state supply and would reduce Arkansas's need for interstate transportation of gas. Working with existing pipelines to improve existing or develop new interconnects to other pipelines and exposing Arkansas to

[1] https://www.centerpointenergy.com/en-us/Corp/Documents/Arkansas%20Rates%20and%20Tariffs/OrderofCurtailment.pdf. CenterPoint's curtailment tariff allows it to "take steps necessary for the protection of the reliable and adequate service." Under the policy, "deliveries of gas will be curtailed to whatever extent and or whatever periods Company may find it necessary from time to time in the operation of its system for the primary benefit of human needs customers."

additional supply basins would add incremental reliability. All these options come at a higher cost to the Company, its customers and to upstream service providers.

2. What incentives could the state provide to help ensure an adequate supply of natural gas during extreme weather events?

Response of CenterPoint Arkansas: As a regulated public utility, certainty of recovery of costs necessary for additional supply or transportation options would incentivize additional reliability projects.

3. What would be your recommendations to ensure an adequate supply of natural gas for the state during extreme weather events or other types of supply disruptions?

Response of CenterPoint Arkansas: As mentioned above, CenterPoint was able to obtain all the necessary gas supply required to fully supply its obligations to its sales customers and did not experience any supply failures. Developing local supplies or storage capabilities, working with existing pipelines to improve existing or develop new interconnects to other pipelines and exposing Arkansas to additional supply basins may add incremental reliability.

4. Describe your preparedness and allocation process for critical energy resources during extreme events.

Response of CenterPoint Arkansas: With the support of the Arkansas Public Service Commission, CenterPoint has invested in modernizing its system to ensure that its facilities can reliably serve customers during extreme weather events. CenterPoint's system is designed to serve needs required during a coldest day scenario (i.e. the coldest day in thirty years), supported by corresponding upstream supply services.

5. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Response of CenterPoint Arkansas: CenterPoint notifies curtailed customers pursuant to its curtailment tariff on file with and approved by the APSC. Affected customers are notified via electronic communication such as email or via phone communication. Curtailed customers may request consideration of unique circumstances pursuant to Section 9.8 of the Company's curtailment tariff.

Arkansas Electric
Cooperative Corporation

Reliable · Affordable · Responsible

1 Cooperative Way
P.O. Box 194208
Little Rock, Arkansas 72219-4208
(501) 570-2200

ENERGY RESOURCES PLANNING TASK FORCE INQUIRY RESPONSE

Sent via email on April 30 to: ERPTaskForce@adeq.state.ar.us

BACKGROUND:

AECC is a generation and transmission electric cooperative owned by our 17 Member Cooperatives, who serve approximately 1.3 million Arkansans in 74 of Arkansas's 75 counties. More information about AECC is online here: https://aecc.com/about-us/. Because AECC is a non-profit utility, organized as an I.R.C, § 501(c)(12) cooperative, we support any efforts that would result in lowering the overall cost of electric service to Arkansas' end-use consumers. In that vein, AECC appreciates the Task Force's efforts to investigate the circumstances around the February 2021 extreme weather event, particularly given our membership bore both the financial and operational brunt of circumstances outside of our control.

Should you need additional information supporting these responses, please contact Jennifer Loiacano, AECC's NERC Compliance Supervising Attorney, at 501.570.2187, Jennifer.Loiacano@aecc.com, or AECC's General Counsel, Lori L. Burrows, at 501.570.2147 or Lori.Burrows@aecc.com, and they will assist in getting relevant and timely information to the Task Force.

ELECTRIC UTILITIES

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

   - In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event? What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?

     RESPONSE: The primary causes of the electric power shortage were the unprecedented and extraordinary nature of the weather event, which was widespread across the continental US and longer in duration than any weather event in recent history. The widespread nature of the event, coupled with record low temperatures, created an all-time high demand for energy from electric utilities, a constraint in fuel supply and a lack of dispatchable resources.

     Mitigation strategies are identified in the responses to Question Nos. 4, 7 and 8.

- Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future? Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?

  RESPONSE: AECC has ongoing, internal reviews to identify the root causes and appropriate additional strategies to mitigate the results of such matters in the future. To support grid stability, AECC has historically relied on a mix of generation, as a means to avoid over reliance on one type of generation.

  Other extraordinary events that could significantly affect power availability include earthquakes, widespread flooding, and terrorist events.

- What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?

  RESPONSE: AECC's evaluation of potential preventive, future measures is underway. AECC's evaluation will include a cost-benefit analysis for system and end-use consumers' needs.

2. With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

   RESPONSE: AECC, as well as other utilities throughout the state, is currently, and continually, reviewing and adjusting its generation mix to ensure the proper allocation and availability of resources, as mentioned above.

3. With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

   RESPONSE: Currently many utilities manage capacity based on the requirements of the Regional Transmission Organization (RTO, i.e., SPP and MISO for Arkansas) they are in. The RTOs assign capacity values to renewable resources that are added to the generation mix. Currently the SPP and MISO interconnection queues are almost entirely full of new wind and solar resources that get capacity credit. In other words, it appears reliance on wind and solar for capacity will increase, perhaps significantly. The RTOs should be held accountable to ensure that increased reliance on these resources for capacity does not increase the number and magnitude of energy emergencies such as occurred with the extreme weather event in February. Also, the RTOs should be held accountable to a reasonable and reliable dispatchable reserve margin. Since all utilities rely on the market, it is essential that this step be right. Actions to ensure reliability by a single utility will have minimal value; actions must be required and adopted RTO-wide.

4. Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?

   RESPONSE: The onsite fuel storage processes AECC has implemented, as well as local fuel availability, provided the most significant backup through the recent cold weather event. These onsite storage processes provided enough coal to span the duration of the severe weather event, even with the freezing issues that decreased generation output levels. Also, AECC was able to replenish diesel fuel used at one of its dual fuel plants where natural gas was unavailable during that period. AECC will continue to evaluate cost-effective ways to further expand on-site storage of fuels to both reduce costs and help make the overall electric system even more resilient. On-site fuel storage could be key to the reliable contribution of future power plants in Arkansas.

   With respect to emerging technologies, currently available electric battery storage systems have relatively short useful lives and the associated costs are too high for broad economic application to electric grid supply. However, battery system costs are gradually decreasing and technologies are being developed that are expected to achieve longer useful operating lives. Electric battery storage as well as advances in pumped storage hydroelectric plants will continue to be evaluated for overall benefits, including how those could assist in mitigating episodic and severe weather events. These short-term storage devices can also provide effective ancillary services to the wholesale energy markets (e.g., fast ramping up and down) although the volume of need for those services is relatively small in comparison to the overall volume of the markets.

5. What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event? Are there constraints or impediments in place that would prevent implementation of such changes?

   RESPONSE: See the response to Question 4 above. Battery and pumped storage hydroelectric systems provide short term storage cycles (typically 2-4 hours for batteries and 6-12 hours for hydro). These systems would be of little value for the most extreme weather events, given they are not currently well-suited to supplying power on a continuous basis for multiple days, such as the grid experienced in mid-February 2021.

6. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

   RESPONSE: All sources of load reduction are beneficial when the demand is outstripping supply, but it is unclear the degree to which EE programs contributed to load management during the severe weather event.

7. Describe your preparedness and allocation process for critical energy resources during extreme events.

   RESPONSE: AECC's wholly owned facilities did well during the February 2021 severe weather event with only minor weather-related issues beyond the ability to obtain fuel. To prepare for the event, all AECC wholly owned and operated plants performed cold weather checklists applicable to their respective facilities in anticipation of cold weather prior to the winter season and immediately prior to the February cold weather event. Generation facilities also increased monitoring, focusing on the anticipated effects of the severe weather and to provide staff adequate time to address issues pro-actively. All fossil fuel plants that operated during the severe weather augmented resources with additional operations and maintenance staff. Supervision was on site most of the event and available by phone, if needed. Plant management provided daily updates, and generation facility needs were prioritized to ensure generation was maintained.

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

   RESPONSE: AECC and the 17 Member Cooperatives maintain an Emergency Load Conservation and Curtailment Plan (ELCCP)[1] that establishes a process for curtailing load, when needed, such as during the recent severe weather event as required by NERC, SPP, and approved by the Arkansas Public Service Commission (APSC). AECC, as included in the approved APSC tariff, will notify the APSC and other appropriate governmental agencies and file any necessary follow-up reports to meet APSC and/or other governmental agency requirements following a curtailment event.

   Each Member Cooperative has its own process for notifying its end-use, retail consumers in the event of curtailment, including notification by phone, media outlets (local news stations, radio stations, newspapers), social media, and other public outlets.

[1] *See* Arkansas Electric Cooperative Corporation Tariff on file with the APSC, Schedule Emergency Load Conservation and Curtailment Policy, available at http://www.apscservices.info/tariffs/2_elec_1.PDF.

AMPA ARKANSAS MUNICIPAL POWER ASSOCIATION

April 30, 2021

Arkansas Municipal Power Association's

Responses to Questions Presented by the Arkansas Energy Resources Planning Task Force

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I. Introduction

The Arkansas Municipal Power Association (AMPA) appreciates the opportunity to provide our responses to the questions presented by the Energy Resources Planning Task Force. AMPA is composed of the 15 municipal electric utilities (MEUs) that serve over 425,000 Arkansans. These MEUs are diverse. Five of the ten largest cities in Arkansas are served by MEUs. Conversely, the five smallest MEUs serve a combined population under 20,000. They are divided between the footprints of SPP and MISO, with one, the City of Prescott, having the unique and unfortunate distinction of being included in both. MEUs generate and/or purchase electric power for customers from a variety of sources, including:

- Shared or sole ownership of electric generating units;
- Contracts for the full or partial output of electric generating units;
- Contracts for fixed amounts of energy and/or capacity;
- Contracts for variable amounts of energy and/or capacity based on load;
- Allocations from the Southwestern Federal Power System; and
- Direct purchases of energy and capacity through markets managed by MISO and SPP.

The power resources described above include a diverse mix of fossil fuel and renewable generation resources. Seven MEUs have direct financial interests in coal-fired electric generating units located in Arkansas. Four MEUs have local gas or petroleum-fired electric generating units. Ten MEUs have renewable generation resources, including: (1) 239.5 MW of hydropower that is owned or purchased through contracts; and (2) 170 MW of solar power that is owned, purchased through contracts, or under contract for development. Additional solar development is being planned. Contracts and market purchases are typically silent regarding the source of energy and/or capacity purchased and may include a variety of resources.

II. Responses to Questions

1. ***Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas*****:**

- ***In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event?***

Response**:** During the February winter event, some AMPA members experienced curtailments due to electric power shortages, but others did not. Curtailments, when they occurred, were limited in duration. Thus, from AMPA's perspective, the February winter event did not result in an electric power shortage as much as it resulted in the replacement of low-cost generation with high-cost generation while demand peaked. This created severe upward pressure on market prices and in turn pushed higher costs onto load serving entities, like MEUs.

AMPA attributes the alarming prices experienced during the February winter event to: (1) increased demand for electricity; (2) reduced output from generating units that typically produce electricity at favorable prices; and (3) increased cost of natural gas. In MEUs, homes and businesses rely on electricity for heat. It is often their sole source. The extreme cold temperatures caused these customers to consume electricity at near-record levels. While the demand for electricity was peaking, many low-cost generators struggled. Some plant components were either frozen or too cold to operate. There were reports of frozen coal piles and frozen natural gas wellheads. Pricing in the natural gas market – which had been relatively stable at $3/mmbtu – soared to over $1,000/mmbtu. Further, renewables did not seem prepared to fill the gap. The SPP market, for example, seemed significantly impacted by a loss of wind energy that normally provides an abundance of affordable power. Overall, AMPA believes that extreme cold temperatures caused a simultaneous increase in demand for electricity, decrease in affordable generation, and spike in natural gas pricing which resulted in record market prices for electricity.

- ***What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?***

Response**:** AMPA members reported that voluntary curtailment was the primary mitigation strategy to manage price exposure during the February winter event. Additional mitigation strategies used by AMPA members vary based on the methods they use to purchase or generate electricity.

a. Single provider. Some AMPA members depend on a single wholesale power provider for all of their energy, capacity, and ancillary service needs. These MEUs typically have contract terms that restrict their ability to enter contracts with other providers or construct generation that would mitigate exposure during peak events. They are fully dependent on the diligence of their wholesale power provider. In general, most MEUs in this situation fared well. However, the MEUs that rely on SWEPCO as their wholesale provider received bills that were five times greater than average. The City of Bentonville, expecting a monthly bill of approximately $4M, was billed over $20M for the month of February. Similarly, Hope Water & Light and the City of Prescott saw costs increase by approximately $5.2M and $2.0M, respectively. The combined losses of the three AMPA members served by SWEPCO exceed the combined losses of the other twelve AMPA members.

b. Contract purchasers. Some AMPA members depend on layered energy contracts ("block purchases") to mitigate exposure to market swings. These contracts reduce market exposure in accordance with the risk management policy of the utility and often rely on weather forecasting. The NOAA's weather forecast contributed to greater volatility for contract purchasers because, as late as January 27th, it predicted an unseasonably warm February. Thus, load was projected at lower levels. The resulting gap between forecasted load and actual load caused some AMPA members to purchase more wholesale power in the Day-Ahead and Real-Time markets than was projected, while those markets were peaking.

c. Local Generation. Some AMPA members use their own electric generation assets to mitigate exposure to market swings. MEUs that own generators reported that they used checklist procedures to verify preparation for cold weather operations. However, additional procedures were required for the February winter event. Maintenance teams worked around the clock to keep units warm enough to start. Portable heaters and tarps were used to protect external components.

For owners of natural gas generators, fuel supply was particularly challenging. Paragould Light, Water and Cable (PLWC) relies on 32 MW of local natural gas generation to mitigate peak events. These generators were ready and available to run but had no fuel. Conversely, Jonesboro City Water and Light (CWL) was able to coordinate natural gas delivery through Tenaska. The financial impact of the February winter event on these two municipal utilities demonstrates the importance of natural gas supply. CWL incurred no significant financial impact during the event while PLWC had increased costs of $8,500,000.

- ***Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future?***

Response**:** AMPA believes that additional strategies could be employed to improve the reliability of electric power in Arkansas.

a. Improve the ability of natural gas production to ramp-up during peak events.

b. Improve market-to-market coordination between SPP and MISO. The distribution systems of CWL and PLWC are approximately 15 miles apart, but CWL is in MISO's footprint and PLWC is in SPP's footprint. At one point during the event, CWL attempted to support PLWC by moving power across a transmission line between the two cities that is owned by the federal Southwest Power Administration. The line appeared to have capacity to support the transfer. However, when CWL and PLWC followed the necessary processes to "tag" the transmission between the systems, neither MISO nor SPP would approve it. AMPA submits that if one ISO served the state of Arkansas instead of two, the event described above would not have happened. If Arkansas is to be served by two ISOs, these ISOs need to coordinate their efforts to best serve the needs of the state.

- ***Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?***

Response**:** Regional transmission organizations like MISO and SPP have sophisticated models to balance electric demand with generator availability. However, despite their efforts, there are scenarios or a combination thereof that could result in inadequate power. First, unexpected transmission outages could occur resulting in constrained generation. Second, unexpected generation outages could occur resulting in lowered supply that is inadequate to meet demand. Third, forecasting errors could result in demand that is higher than available generation. Fourth, generators could underperform resulting in insufficient generation to meet demand. Fifth, generators or transmission lines could be disabled by terrorist or cyber-attack. Finally, the retirement of EGU's without sufficient replacement of dispatchable generation capacity could result in inadequate generation to meet demand.

- ***What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?***

Response**:** Arkansans currently benefit from an abundance of electric generation capacity. To preserve this benefit, the pace of new capacity installations must meet or exceed both: (1) planned retirements; and (2) reasonably foreseeable increases in load, particularly increases in load that will result from electrification of the transportation sector. Consideration should also be given to the importance of a diverse fuel mix. Dispatchable base load units, like those powered by fossil fuels, will be critical to maintaining a reliable electric grid.

As new generation is developed, transmission systems must be modified to facilitate the delivery of energy. AMPA believes that transmission systems need to be able to adapt to the changing generation landscape without creating an undue burden on consumers.

2. With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

Response: AMPA believes that the owners of electric generating units as well as owners of fuel supply infrastructure should evaluate additional measures to better winterize their assets in light of the February winter event. In this regard, AMPA does not ignore the importance of cost/benefit analysis. Coal units in Arkansas are designed to operate in a summer peaking region. AMPA would not seek to improve winterization for coal units that would decrease the summertime efficiency.

Additionally, better coordination between fuel and electric markets is needed to ensure that appropriate amounts of fuel will be available when needed.

3. With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

Response**:**

a. Reasonable and predictable environmental standards. AMPA believes that the current electric generation capacity mix is threatened by national environmental policy. AMPA members that have invested in coal-fired plants are anticipating early retirements and, in some cases, stranded costs. Given that experience, AMPA members will be hesitant to invest in any fossil fuel resource that appears to be threatened by environmental regulation. Unfortunately, AMPA is unaware of any economically viable solution to provide peak power during extreme weather events over the next decade that is not based on fossil fuel.

b. Reliable supply of natural gas. Generators fueled by natural gas tend to be the most responsive during emergencies. However, as shown in the February winter event, natural gas generation is only as helpful as the availability of fuel. Thus, a reliable supply of natural gas is key to serve peak load during extreme weather events.

4. Are there reasonably available storage solutions for electricity that could be implemented in the state?

Response: AMPA believes that pumped-storage hydropower and new battery technology are both available for implementation in Arkansas, but both have drawbacks, particularly related to cost.

a. Pumped storage. Arkansas has substantial water resources. Pumped-storage hydropower is a proven method to store energy at utility scale. Pumped storage is challenged by high-capital costs and environmental issues, particularly those related to the killing of fish.

b. Batteries. Battery technology is rapidly improving and costs continue to decline. Unfortunately, batteries do not appear to be an economically viable option for large scale energy storage at today's prices.

- ***What are the barriers or impediments to deployment of storage technologies?***

Response**:** AMPA believes that the primary impediment to deployment of storage technology is cost and the related impact on ratepayers. Other impediments include environmental concerns and uncertainty of value in changing markets and regulatory frameworks.

- ***Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?***

Response**:** AMPA believes that additional value can be derived in day-to-day operations of energy storage facilities. For example, energy storage facilities can be used on a daily basis to essentially trade electric consumption during off-peak hours for generation during peak hours. Energy storage facilities can also be used to offer voltage support and other ancillary services to the grid. The administrative costs of achieving these additional values must be considered as part of the cost/benefit analysis of developing the energy storage facility.

5. What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event?

Response**:** AMPA is unsure of existing dispatch processes used by ISOs to charge energy storage facilities in advance of a storm, or what FERC and NERC allow. In the event of a forecasted extreme weather event, ISOs, in coordination with storage system owners, should be allowed to increase generation in those areas to help the storage systems reach full capacity. Further, assuming coordination with the ISO has been achieved, owners of storage devices should be held harmless from market volatility/penalties during those approved times of energy storage.

- ***Are there constraints or impediments in place that would prevent implementation of such changes?***

Response**:** AMPA is unaware of any constraints or impediments that would prevent the ISOs from implementing changes related to energy storage but acknowledge that FERC and NERC will have oversight of any such changes.

6. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event?

Response: MEUs are not regulated by the Arkansas Public Service Commission and lack the ability to provide constructive comments on the impact of energy efficiency programs on load shedding.

- ***Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?***

Response: AMPA encourages the Energy Office to adopt policies that discourage electric strip heating as a primary method to control indoor temperatures. Compared to heat pumps, electric strip heating consumes a significant amount of electricity which, in turn, affects the cost of power during winter months. However, while such policies would be beneficial in most circumstances, they would not likely reduce the cost of power during an extreme weather event when secondary sources are required for heat. AMPA encourages the Energy Office to consider energy efficiency rules, targets and programs that financially benefit end users in an amount that reasonably exceeds costs, and implements technology that is both affordable and reasonably available.

7. Describe your preparedness and allocation process for critical energy resources during extreme events.

Response**:** AMPA members did not report using any allocation processes for critical energy resources during extreme events. Thus, the responses below only pertain to preparedness. Similar to the response in question #1, the efforts used by AMPA members to prepare for extreme events varies based on the methods they use to purchase or generate electricity. All AMPA members reported reviewing curtailment processes in preparation of an extreme event.

a. Single provider. AMPA members that depend on a single wholesale power provider for all of their energy, capacity, and ancillary service needs are prohibited from constructing or purchasing power from energy resources that would mitigate the impacts of an extreme event.

b. Contract purchasers. AMPA members using layered energy contracts ("block purchases") to mitigate market exposure will typically increase the volume of purchases when an extreme event appears likely. This strategy reduces the volume of purchases made in the Day-Ahead and Real-Time markets when they are most volatile.

c. Local Generation. AMPA members using their own electric generation assets to mitigate exposure follow checklist procedures to ensure generators will be available when an extreme event appears likely. Some notable procedures used during the recent February winter event are:

i. Insulating main run piping using extruded polystyrene foam with an R5 insulating value;
ii. Insulating valves, pipe functions, filter pots and other sections requiring service access using custom blanketed insulation coverings with an R3 value;
iii. Installing heat tracing cable for water systems have been installed and are a combination of 3W and 5W per foot. Cables consisted of either continuous operation or self-regulating type;
iv. Applying additional heat to liquid fuel regulators; and
v. Applying additional heat and skid coverings to turbine packages and ancillary skids.

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Response: AMPA members strive to provide customers as much advance notice as possible when curtailment is required. Curtailment efforts are focused on disrupting the fewest customers for the shortest period of time possible.

Curtailment efforts often start with industrial customers. AMPA members make direct contact with customers to allow industrial systems to be powered down in an orderly fashion. Commercial and residential customers may be notified through a variety of methods. Social media, text messaging, and automated phone calls are common. Some AMPA members also provide cable and/or broadband services that are be used to communicate pending curtailments.

In any curtailment, some customers will request to be exempted based on their particular circumstances. These requests appear to have increased with the increased use of CPA machines. AMPA members that they seek to accommodate requests according to standards that will treat all persons equally. However, not all requests for accommodation can be met. When curtailment is done by opening breakers on distribution lines, individual requests for accommodation by customers on those lines cannot be met. On the other hand, some AMPA members that have installed smart meters with remote-disconnect capability and have more flexibility in managing curtailment at the individual customer level.

III. Summary

AMPA appreciates the efforts of the Energy Resources Planning Task Force to better understand the various causes of increased electricity costs during the February winter event and, more importantly, to develop strategies to mitigate these costs in the future. We are hopeful that our responses to your questions will help you accomplish these goals. We will continue to support the efforts of the Task Force as needed.

Liberty™

TESTIMONY
OF
LIBERTY UTILITIES

PREPARED FOR

THE STATE OF ARKANSAS
ENERGY RESOURCES PLANNING TASK FORCE

APRIL 30, 2021

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

> • In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event? What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?
>
> • Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future? Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?
>
> • What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?

<u>LIBERTY RESPONSE</u>

In the Company's opinion, the primary causes of the electric power shortage in Arkansas during the February winter event were the following: 1) the historically extreme weather conditions (cold temperatures and large snowfall amounts); 2) record-breaking peak demand because of these conditions; 3) fuel supply disruption and shortages, particularly in natural gas; 4) hampered generator availability; and 5) diminished transmission capability.

The Company undertook the following mitigation strategies: 1) curtailment of large industrial and commercial customers; 2) issued periodic peak advisories (social media and other communication channels) to both residential and commercial customers throughout the duration of the event asking customers to conserve energy; 3) implemented controlled interruptions of service to a limited amount of customers (typically in 1-hour blocks); provided outage updates to customers regarding the actions being taken by the Company.

Regarding additional strategies that could be employed in the future to further enhance the Company's ability to provide sufficient power during an extreme weather event, the Company believes that both improved weatherization of critical fuel supplies, particularly natural gas, and improved weatherization of generating facilities would be beneficial. The facts surrounding the February winter event and causes related to fuel supply disruption hampered generator availability and diminished transmission capacity are still being reviewed. As additional information is received, other strategies may be developed to enhance the Company's ability to provide sufficient power during an extreme weather event.

There are other events that could impact electric power availability. Some examples include as acts of terrorism, acts of war, and natural disasters such as earthquakes, floods, and tornadoes.

Regarding additional strategies, regulations, protocols and/or policies that should be developed by the industry or the government to insure Arkansas has an adequate power supply, in the Company's opinion, the electric industry should continue to strategize with stakeholders as to issues such as the future generation mix, advanced planning for extreme weather events, demand-side management, and technologies that improve reliability.

2. **With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?**

<u>LIBERTY RESPONSE</u>

In the Company's opinion, steps that can be taken to ensure that the current electric generation capacity mix can provide sufficient generation to serve peak load include both improved weatherization of critical fuel supplies, particularly natural gas, and improved weatherization of generating facilities.

3. **With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?**

<u>LIBERTY RESPONSE</u>

In the Company's opinion, changes to the electric generation capacity mix over the next decade will have to take into consideration the requisite reliability and availability of this particular mix of resources under any extreme condition. This could include technological advancements in generation, transmission and distribution, ensuring adequate supplies of the required fuel (excluding wind and solar), advanced event planning, grid modernization, and future on-grid/off-grid usage considerations (residential/community solar, micro-grids, etc.).

4. **Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?**

LIBERTY RESPONSE

In the Company's opinion, reasonably available storage solutions for electricity in Arkansas are being evaluated. Pumped hydroelectric storage may be available for some electric utilities in Arkansas, but Liberty does not have access to these facilities with its current run-of-the-river hydro facility, Ozark Beach. Viable, industry grade, battery storage technology is continuing to improve and Liberty will be evaluating its potential in its upcoming Integrated Resource Plan ("IRP") in Missouri (expected completion April 2022). As discussed in DR 0005, storage solutions have value in the existing market construct for such things as Day-Ahead and Real-Time market price arbitrage, ramp products, and operating reserves. However, investment signals related to additional reliability-based products and the continuing advances in technology that extend capacity and life and lower costs for battery storage would likely lead to quicker adoption of energy storage.

5. **What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event? Are there constraints or impediments in place that would prevent implementation of such changes?**

LIBERTY RESPONSE

In the Company's opinion, and assuming adequate and reliable storage systems are in place, integrated system operators would have the capability to dispatch additional generation for storage in advance of anticipated emergency events. Ideally market products would be created through, in Liberty's case, the Southwest Power Pool ("SPP") working group process that would send the correct investment signals to market participants. Without specific market product design for the purposes of storage to serve reliability, investment will only occur when value can be created from existing market products like price arbitrage and/or market ramping products. A focus needs to be placed on the blending of economic signals for reliability-based needs.

6. **To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?**

<u>LIBERTY RESPONSE</u>

For Liberty, the implementation of energy efficiency programs in Arkansas had a minimal impact on reducing the need to shed load during the February weather event. The impact of energy efficiency programs was a reduction of approximately 0.2% of energy sales in Arkansas in 2019.

Regarding any changes that could be made to energy efficiency rules, targets or programs, energy efficiency targets could be changed and programs could be increased. However, any increases in these areas would have to take the associated costs and impacts on customer bills into consideration. Just as the current impact on load is minimal, the current cost impact on customers is minimal. The current cost impact is roughly $2.00 a month for residential customers.

7. **Describe your preparedness and allocation process for critical energy resources during extreme events.**

<u>LIBERTY RESPONSE</u>

Transmission Operations
Multiple internal calls occurred in relaying the intent of the effort, revisiting/refreshing the "Emergency Operations Procedures ("EOP") Manual (specifically Section 7) as it related to the possibility of entering a load shed event and providing lists of the load shed blocks within the EOP manual to Line Operations so that they could position personnel to respond to unforeseen issues that are typical in cold weather events. Internal contact information was shared and internal points of contact were identified so that the conveyance of information would be as efficient as possible. Next, The Empire District Electric Company ("EDE") held calls with a neighboring utility (Evergy, formerly Westar ("WERE")) on a co-owned transmission line which has historically been the most congested path on a Market-to-Market basis. These efforts occurred over the weekend preceding the extreme temperatures and were in anticipation of

heightened transfers which would be required between the two markets of impact/interest (SPP & MISO). The transmission line of specific interest was the shared 161kV line between EDE's Riverton station to that of WERE's Neosho station. Both entities agreed to an increase in the rating of this facility by approximately 25%. EDE's intent was to ensure our customers would have access to as much energy as possible should contingencies occur on both the transmission system(s) and/or the generation units. EDE's efforts also ensured that generation on the western portion of our system would be load serving/supporting versus allocated to offsetting of congestion during heightened demand. EDE was glad to support our customers in taking these actions at the forefront.

T&D Operations
Several days in advance of the weather event, Liberty T&D operations personnel began monitoring the load at several critical substations. Operations Managers directed the manipulation of load on several distribution circuits to mitigate the possibility of circuit interruption due to overloading, or load imbalance. Substation operations personnel inspected and made operational any heating devices associated with all substation equipment. Gas levels on station transformers were verified as satisfactory and adjusted as necessary.
Due to the pandemic, line and substation personnel are beginning their work shifts from home utilizing company vehicles as transportation to and from their home base to the job site. Response time to outages is diminished due to the absence of travel time to a service center where company vehicles are normally housed. In advance of the winter weather event, Operations leadership changed the work shift of select crews across the service territory to an earlier start as to have operations personnel ready to respond to any system disturbance as the load increased.

Generation Operations
Throughout EDE's generation fleet there were multiple steps taken to ensure we were as prepared as possible. Some actions were taken during original construction and design and others were more short-term. For example, we purchased the low temperature option on the wind turbines which is designed to maintain adequate oil temperature to allow operation to – 30 C (-22F). The ambient temperature never dropped to this level, and as a result, none of the turbines tripped due to low temperature protection in the cold weather package. At other facilities we reviewed our cold weather procedures, confirmed operation of freeze protection, and confirmed inventory of temporary heat trace supplies. During previous planned outages in the fall we installed skirting in preparation for winter, per our normal outage procedures and other facilities went through their plant winterization list. Also, cold weather operation was a point of emphasis throughout each day and at each shift turnover. Lastly, we implemented a plan last year to carry 10 days of fuel oil at one of our dual fuel units and another 7 days of fuel oil at our other facility that has dual fuel capabilities.

Power Marketing/Fuel Procurement

After the first week of February, as weather forecasts began to predict more extreme temperatures, Empire procured additional fuel sufficient to operate Riverton Combined Cycle and State Line Combined Cycle at their maximum output . Additionally, prior to the period, the fuel oil tanks for State Line Unit 1 and Energy Center Units 1 – 4 were at full capacity with enough fuel oil to operate the dual fuel units at full capacity around the clock for seven (7) and ten (10) days respectively. Throughout the period, Company personnel monitored and analyzed natural gas cut notifications (received over 300 cut notices between February 6^{th} and February 19th) and adjusted plant operations as necessary to maintain operational reliability and minimize the potential financial impact of over-delivery, including Operational Flow Order (OFO) penalties.

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

RESPONSE

Empire has processes defined and prescribed in our Emergency Operations Procedures ("EOP") manual for the implementation of curtailments and load shedding. Curtailments are defined as a Code Yellow event and occur on an as needed basis due to system conditions warranting the alleviation of load from Empire's system or when instructions are received from the Regional Transmission Organization ("RTO") due to grid conditions. Conditions requiring curtailments and load shedding include, but are not limited to, Energy Emergency Alert ("EEA") Level 2 Alerts issued by the RTO, conditions established by the North American Electric Reliability Corporation ("NERC"), emergency situational awareness, Transmission Operator determination, and RTO instructions. The implementation timeline of curtailments is dependent on the nature of the grid conditions at the time of the need. Empire Operators and/or Empire management will decide when a Voluntary Load Reduction Plan will be implemented and notify internal personnel of the need so that customers can have adequate time to voluntarily reduce their load. These loads generally consist of industrial customers which have the ability and have agreed to reduce their load upon notification from Empire personnel. In addition to voluntary customer curtailment, Empire makes internal notifications to company facilities to eliminate all non-essential consumption to support the overall load reduction efforts. Finally, Empire makes public appeals to its customers to reduce load across the entire system through various available platforms such as direct email notifications to customers and social media posts.

Load shedding is implemented under Code Red events based upon emergency conditions such as the inability to serve load on a local Operator level if the Transmission Operator determines there is inadequate transmission or generation capacity available to serve the load present on the system. Similar declarations can be made by the RTO under an EEA Level 3 Alert when operating reserves are below required minimum levels. As a result, the RTO prescribes the gross amount of load each entity is required to shed (typically on a Load Ratio Share of the shortfall present within the RTO Regional assessment).

Transmission Operators utilize pre-determined blocks of feeders to deenergize, with each block generally consisting of approximately 50MW of load available to be shed. As many of the blocks as needed (including partial blocks) are implemented to meet the gross MW requirements of the load shed event. The blocks are determined by way of previous circuit analyses to avoid deenergizing both public support functions as well as critical customers. Critical customers include, but are not limited to, hospitals, nursing homes, water treatment plants, fire/rescue/police, jails, communication hubs and warming/cooling centers. Empire makes every attempt to avoid impacting these customers in an effort to best support the general public, but cannot guaranty facilities will be insulated from possible impacts from a load shed event as system conditions and directional flows may change over the course of time. Empire also compiles the blocks so as to not cluster feeders within a common geographical area so that customers on feeders which have been deenergized will have alternative means to seek help should the need arise. Empire also makes every attempt to ensure entire communities are not disconnected so that an entire region is not impacted, but rather that the impacts are spread out throughout the entire service territory. The final vetting process makes every attempt to not overlap the Underfrequency Load Shed circuits. This effort helps to ensure the resiliency of the network should frequency start to deteriorate across the local and/or Regional systems. In doing so, this ensures the integrity of the network as best possible during times of rapidly changing, highly compromised infrastructure (inability of generation, transmission contingencies, etc.).

OGE Energy Corp. 321 N. Harvey
Oklahoma City, OK 73101-0321
405-553-3000
oge.com

OG&E

May 7, 2021

Arkansas Energy & Environment
Energy Resources Planning Task Force
Email: ERPTaskForce@adeq.state.ar.us

Dear Energy Task Force:

In response to the Energy Resources Planning Task Force's ("Task Force") email dated April 9, 2021, Oklahoma Gas and Electric Company ("OG&E) hereby submits its responses to the Task Force's Testimony Questions, as follows:

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:
   - In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event? What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?
   - Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future? Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?
   - What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?

Response: OG&E is a member of the Southwest Power Pool ("SPP"). "SPP is a regional transmission organization ("RTO"): a nonprofit corporation mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices on behalf of its members ."

SPP is responsible for the development and oversight of policies and procedures related to reliable supply adequacy within its footprint including ensuring that the policies and procedures meet the compliance obligations of North American Electric Reliability Corporation ("NERC") Reliability Standards. The primary cause of the power shortage was the significantly cold temperatures that covered the middle of the continental US including the entire SPP region for approximately a week. This week-long event put significant demand on *all* generation resources of all fuel types and technologies and, required them to operate in extreme weather conditions beyond their typical operational conditions.

These conditions resulting in generation unavailability due to lack of fuel supply and icing and extreme cold weather-related outages; rapid reduction of energy imports from neighboring ISOs as a result of transmission congestion and tightening supply conditions in neighboring areas and; record wintertime energy consumption[1].
Throughout the event, SPP remained in communication with its members and utilized various tools to mitigate and prevent as possible, the need to take customers offline. These tools include,

- The use of the Emergency Action Alerts (EAA) which provided notice of current conditions and actions that needed to be taken by operators and members including the need to: delay or defer planned outages for maintenance, return those generation units in outage back to service as possible, curtail 'interruptible' large customers, issue public appeals for energy conservation, relieve transmission congestion and constraints as possible
- Importing energy across the SPP's seams as possible to supplement the native supply and meet the needs of the region's customers.
- Shed customer load as directed as a matter of last resort

These tools were used throughout the week-long event in cycles according to the changing weather conditions and the physical, operational condition of the system including the generators and transmission.
SPP is in process of conducting a multidisciplinary after-action review of the event and is expected to present its report to its board of directors in July. At that time, SPP and its membership will evaluate the findings and develop any needed course of actions. It would be inappropriate to speculate on specifics at this time.
It can be said as a general observation that a diversity of fuels and demonstrated technology in addition to interconnected electricity grids proved invaluable to minimizing the extent of the customer outages that were required.

There are a number of potential events both natural and manmade that could result in inadequate power availability ranging from wildfires to earthquakes to a terroristic attack however, the degree and nature of the potential impact of such events to the system and the ability of the system to respond would be speculative.
With regard to this event, it is premature to speculate until the SPP reports its findings of the after-action review. As a general matter, this event supports the need for sound energy policies, practices & regulation that do not preclude or prematurely foreclose certain energy sources or technologies and, enable market structure and economics to work.

2. With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

Response: The SPP electric generation capacity mix includes primarily natural gas, coal, nuclear, solar, wind, hydro, fuel oil resources. OG&E's maintains and operates natural gas, coal, solar and wind resources. As stated in SPP's Grid Emergency Presentation (please see attachment 1), SPP's "diverse generation mix gave flexibility during storm response." Fuel diversity is a key factor in dealing with uncertainties for weather, fuel supply and cost.

3. With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

Response: SPP is responsible for performing the Loss of Load Expectation ("LOLE") Study[2], which it relies on to determine the planning reserves needed to maintain the reliability metric guidelines specified by NERC. SPP is

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[1]Taken from the SPP BOD material, March 2021 and available at: https://spp.org/documents/64239/special%20bod%20mc%20minutes%20and%20attachments%2020210302.pdf
[2] Available at: https://www.spp.org/documents/62810/2019%20lole%20study%20report.pdf

implementing Effective Load Carrying Capability ("ELCC") as the guiding principle for capacity accreditation of wind, solar and storage resources in SPP so that the intermittent nature of these resources will be considered for accreditation. SPP's ELCC wind and solar white paper states "As the penetration of wind and solar generation increases, SPP and its members need to be aware of and understand the changing impact these resources have on the economics of resource adequacy and on the reliability of the system[3]." SPP, in collaboration with its members, continues to review resource accreditation methodologies for all resources in order to maintain reliable supply adequacy within the SPP footprint.

OG&E in engaged in the development and review of the SPP studies and utilizes the information in each company integrated resource plan. OG&E strives to develop a resource plan that will allow it to meet its capacity obligations over the planning horizon at the lowest reasonable cost with due consideration of the uncertainties attributable to many of the planning assumptions and other items of value to OG&E customers. As the electric generation capacity mix is expected to change in the future, OG&E's objective of fuel diversity maintains a reasonable balance among natural gas, coal and economically viable renewable, energy storage and demand-side resources. Additionally, OG&E's objective of resiliency benefits considers generation capability to minimize disruptions.

4. Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?

Response: There are commercially available battery solutions; however, they are still price prohibitive. OG&E continues to evaluate the reasonableness of deploying batteries and monitor costs which are decreasing and expected to reach more reasonable levels in the coming years. It is also important to note the amount of battery storage required to support OG&E's Arkansas territory through extreme weather events, such as the one experienced in February 2021, would be exorbitant both in scale and cost.

There are several barriers that could hamper the swift deployment of battery storage. First, although increasing, there are currently a limited number of utility-scale battery manufacturers. Second, each bank of batteries is considered its own system requiring specific engineering and the associated Battery Management System ("BMS"). Third, since each bank has its own specific requirements, each system is constructed only after purchase (i.e. there are no off-the-shelf utility-scale batteries). Fourth, a battery built to support power is not equipped to provide long-term energy backup. Finally, the rules on how energy storage will participate at the wholesale level are evolving with two FERC cases, 2222 and 841 and their effect on the Southwest Power Pool.

The following are some examples that battery storage may be used for during day-to-day operations. Batteries installed near generation sources can manage the inherent instability of renewable resources by storing and re-dispatching energy when the wind doesn't blow, and the sun doesn't shine. Batteries located near transmission substations may allow OG&E to store energy near the generation source from "Must Run" facilities, like wind, when transmission congestion is high and re-dispatch the energy when congestion eases. Batteries located across the distribution system near customer loads provide backup power, peak load support, power quality, reliability and resiliency for customers, fast charging for long-haul transportation, and storage for individual net metering customers.

Batteries that qualify to be multi-tasked for other day-to-day functions must use caution to ensure it does not deplete the necessary energy needed in case of any unplanned event rendering its ability to provide backup power.

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[3] Available at: https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf

5. What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event? Are there constraints or impediments in place that would prevent implementation of such changes?

Response: Currently, OG&E does not have any pump or battery storage on its system.

6. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

Response: Since program inception, 2008, 193,580,769 kWh savings has been achieved through OG&E's energy efficiency programs in Arkansas. We could deduct that in the absence of the energy efficiency programs, customers would have consumed the additional kWh, resulting in a greater amount of load shed needed. There are many other variables to be considered, therefore we cannot say with certainty the impact of energy efficiency on reducing the amount of load shed needed. We do not see a need to change the rules.

Table 1-1 Historical Annual Incremental EE Savings Achieved				
Program Year	**Energy (kWh)**	**% Increase from Prior Year**	**Demand (kW)**	**% Increase from Prior Year**
2008	2,434,738		666	
2009	5,607,951	130%	921	38%
2010	4,143,096	-26%	1,317	43%
2011	4,985,328	20%	1,520	15%
2012	7,595,741	52%	1,840	21%
2013	13,410,729	77%	2,797	52%
2014	13,794,070	3%	2,883	3%
2015	20,543,040	49%	3,115	8%
2016	23,257,181	13%	3,434	10%
2017	21,130,663	-9%	3,396	-1%
2018	22,556,832	7%	3,974	17%
2019	26,071,158	16%	4,591	16%

2020	28,050,242	8%	4,878	6%
Total	**193,580,769**		**35,332**	

7. Describe your preparedness and allocation process for critical energy resources during extreme events.

Response: Please see the response to Question No. 2.

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Response: Once SPP notifies OG&E of the potential for load curtailment, OG&E immediately begins communicating to customers load curtailment may occur without additional warning and encourages customers to prepare for the possibility of service interruptions. These notifications are made in conjunction with continued calls for conservation and occur through the following methods:

- Issuance of press release(s);
- Posting "emergency banner" with messaging on company web site, OGE.com;
- Posting messaging to all OG&E social media channels; and
- Emailing customers with messaging.
- Media interviews (television, radio, newspaper, etc.)

Once OG&E receives a curtailment directive from SPP, the load shed must begin immediately leaving inadequate time to specifically notify customers in advance of interruption. OG&E makes every attempt to communicate with affected customers through email and social media to make them aware of the cause of the interruption as well as expected time of restoration. The immediate need to begin curtailment also makes a formal appeal process very difficult. Fortunately, OG&E's curtailment plan aims to avoid interrupting circuits with customers performing critical functions such as hospitals or water treatment centers. OG&E's managed account representatives and community affairs personnel are also in constant contact with customers, particularly those performing critical functions. Although the company seeks to minimize disruption to customers and will continue to seek ways to enhance customer communications in all events, advanced notifications and customer opt out preferences in a curtailment event cannot be considered to the detriment of maintaining the overall reliability and integrity of the grid.

Respectfully Submitted,

Kimber Shoop
Director of Regulatory Policy & Planning

Enclosure: Attachment 1

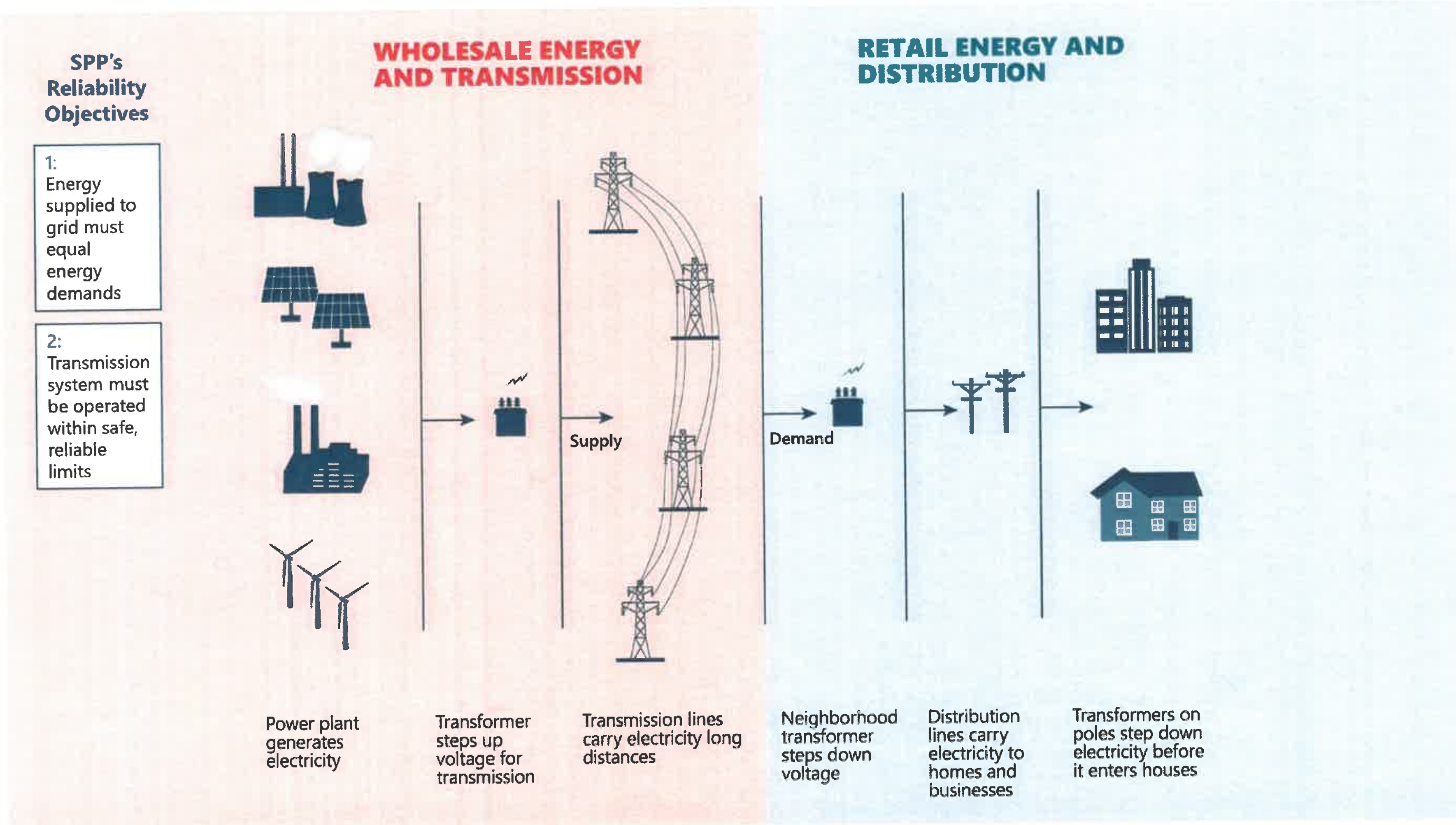
Attachment 1

ABOUT SPP

Attachment 1

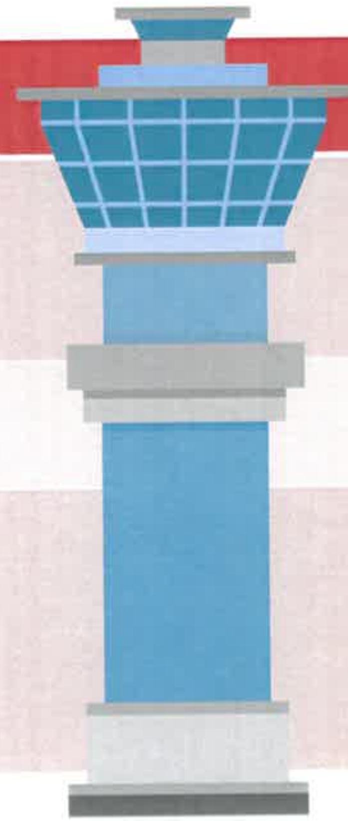
WHO IS SPP?

- 501(c)(6) nonprofit corporation
- One of 9 regional grid operators
- 104 member companies in 14 states
- "Air traffic control" for high-voltage grid
- Balances supply and demand across region
- Maintains reliable grid operations
- Operates wholesale energy market
- Plans future transmission needs



SPP's Reliability Objectives
1: Energy supplied to grid must equal energy demands
2: Transmission system must be operated within safe, reliable limits
WHOLESALE ENERGY AND TRANSMISSION
RETAIL ENERGY AND DISTRIBUTION
Supply
Demand
Power plant generates electricity
Transformer steps up voltage for transmission
Transmission lines carry electricity long distances
Neighborhood transformer steps down voltage
Distribution lines carry electricity to homes and businesses
Transformers on poles step down electricity before it enters houses

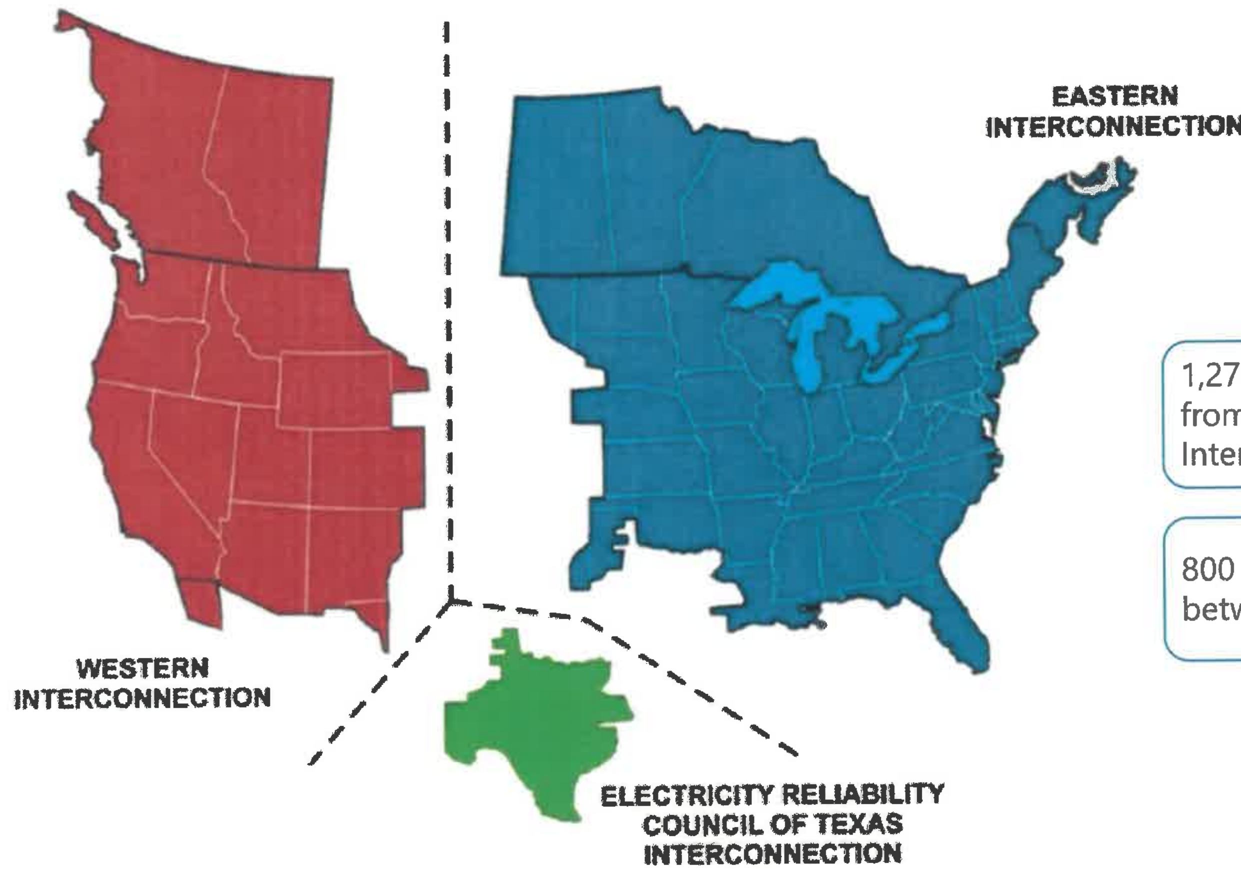
AIR TRAFFIC CONTROL: AN ANALOGY



Air Traffic Control	Southwest Power Pool
Does not own airplanes, airlines or airports	Does not own utilities, power generators or transmission lines
Does not own the airspace it monitors	Does not own the land electricity flows across
Directs air routes to ensure airplanes and passengers are safely transported	Monitors and directs regional bulk power grid to ensure electricity gets from where it's made to where it's needed

Attachment 1

THREE ELECTRIC INTERCONNECTIONS



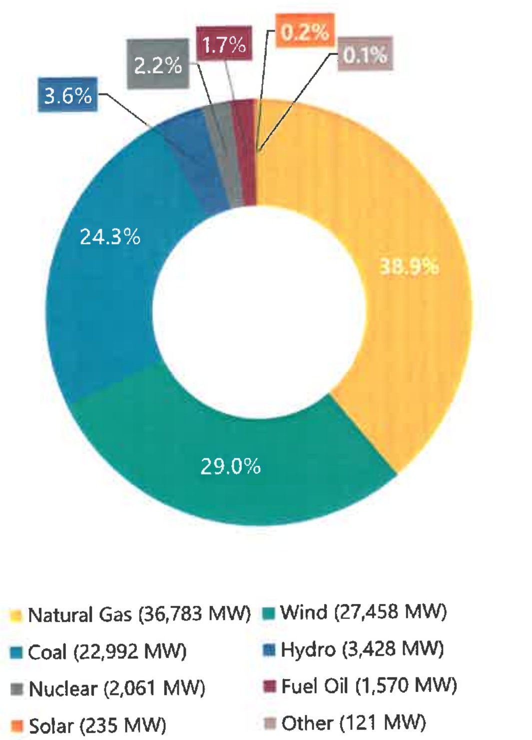
1,270 MW potential transfer capability from Western to Eastern Interconnection

800 MW potential transfer capability between SPP and ERCOT

Attachment 1

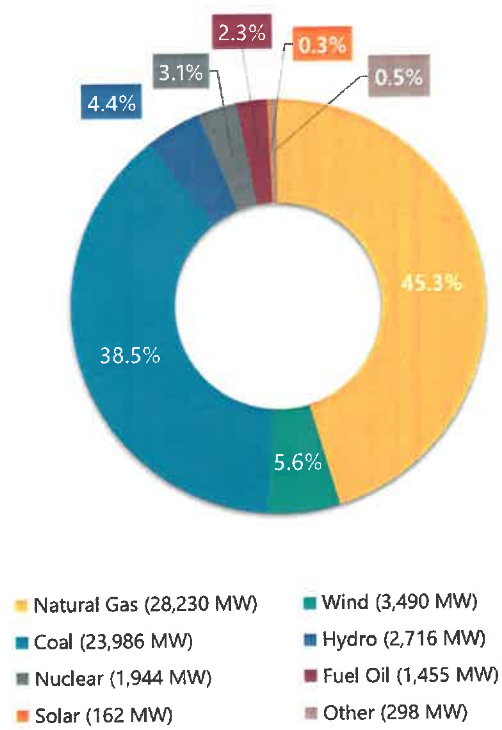
GENERATION IN SPP

NAMEPLATE CAPACITY*
94,648 MW



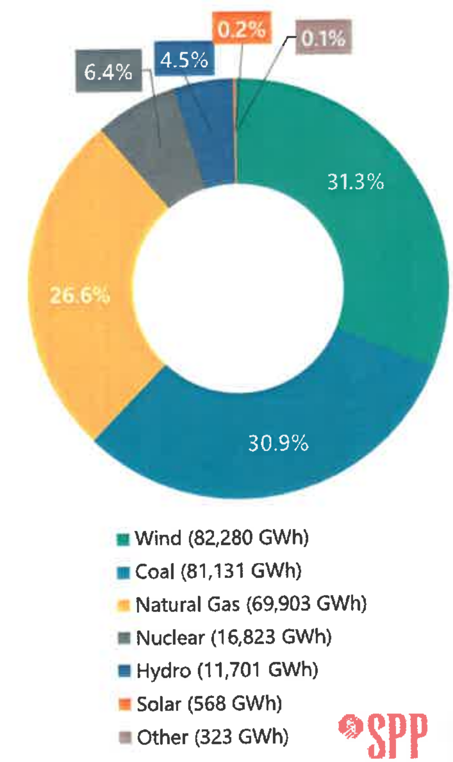
* As of 1/13/21

ACCREDITED CAPACITY†
62,281 MW



†As of 6/15/20

2020 ENERGY PRODUCTION
262.730 TWH



SPP'S EMERGENCY RESPONSE FRAMEWORK

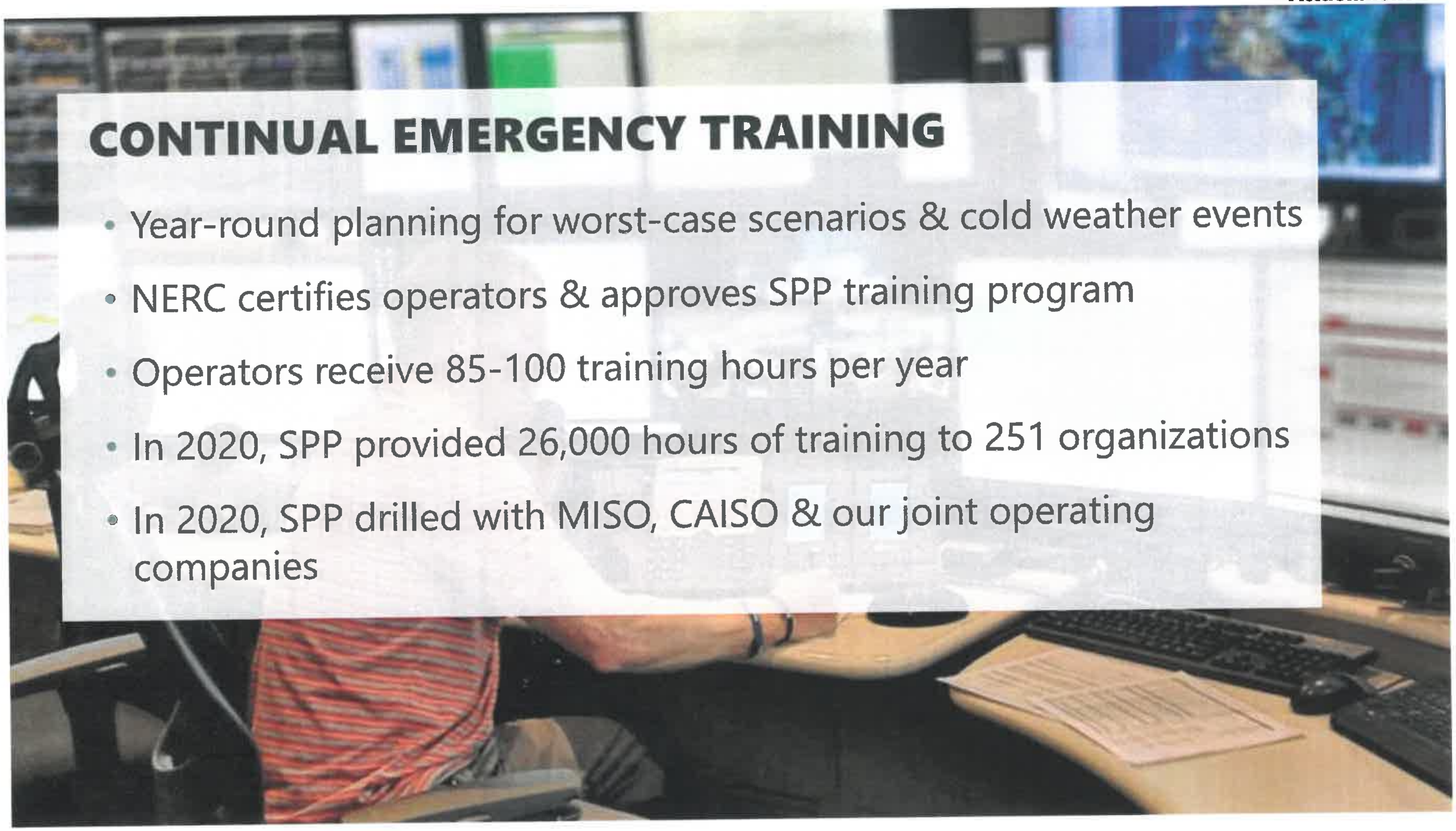
FERC AND NERC JURISDICTIONAL

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

- SPP and utilities must comply with mandatory, enforceable NERC standards
- Government enacted reliability standards after 2003 blackout
- NERC regularly audits SPP
- NERC directs how much energy SPP must keep for emergencies

- FERC approves NERC standards
- SPP must comply with FERC directives

Attachment 1



BALANCING AUTHORITY (BA) OPERATING LEVELS

Levels/alerts defined by SPP operating plans

Normal Operations	SPP has enough generation to meet demand, has available reserves and does not foresee extreme or abnormal reliability threats
Weather alert	SPP expects extreme weather in its reliability coordination service territory
Resource alert	SPP's BA area expects severe weather conditions, significant outages, wind-forecast uncertainty and/or load-forecast uncertainty with potential to impact total capacity.
Conservative Operations	SPP determines the need to operate system conservatively to avoid an emergency based on weather, environmental, operational, terrorist, cyber or other events
Maximum emergency generation notification	SPP foresees the need to use emergency ranges of resources for a certain hours.

Levels defined* by NERC EOP-011-1

Energy Emergency Alert (EEA) Level 1	**All available generation resources in use** • All generation is committed, and there is concern about maintaining required reserves for BA • Non-firm wholesale energy sales curtailed.
EEA Level 2	**Load management procedures in effect** • BA is no longer able to provide its expected energy requirements and is energy deficient • Operating plan implemented, including public appeals and demand response • BA is still able to maintain minimum reserves • Market participants and other BAs notified • Transmission limitations evaluated and revised • BA makes use of all available resources
EEA Level 3	**Firm load interruption imminent or in progress** • BA is unable to meet minimum contingency reserve requirements • System & reliability limits revaluated and revised • Immediate action taken to mitigate undue risk to the Interconnection, including load shedding.

* These are paraphrased, summarized definitions. Full definitions: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

2021 WINTER STORM GRID EMERGENCY

Attachment 1

THE BIG PICTURE

Early prep helped

2/4: Issued cold weather alert

2/8: Issued resource alert

2/11: Committed long-lead generation

Public appeals reduced demand

Demand dropped below forecast, helping minimize interruptions

We used every MW we could get

We ran every available generator and imported energy from neighbors

Service interruptions required

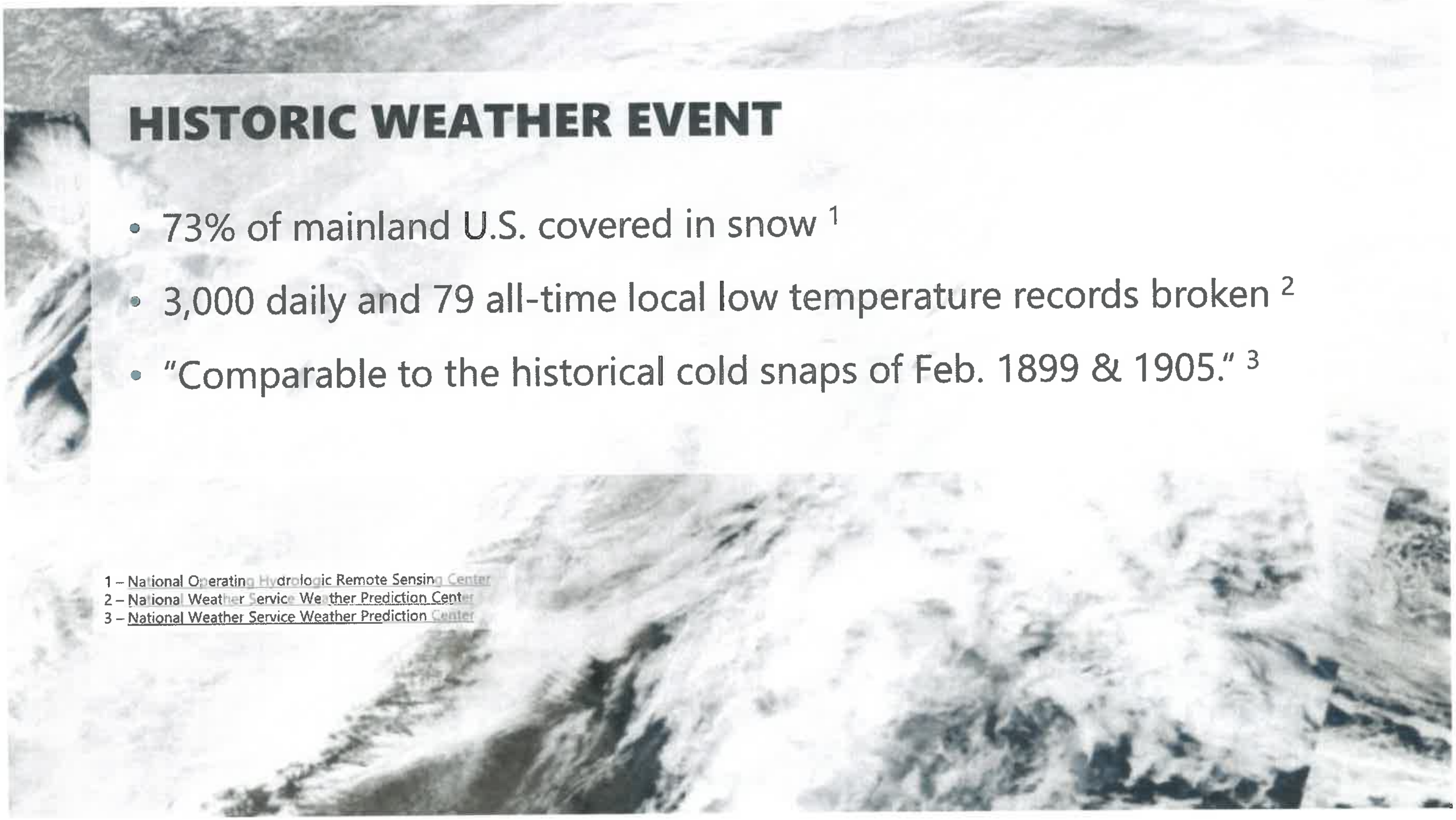
2/15
~1.5% of system demand for 57 min.

2/16
Up to ~6.5% of system demand for 3 hr. 23 min.

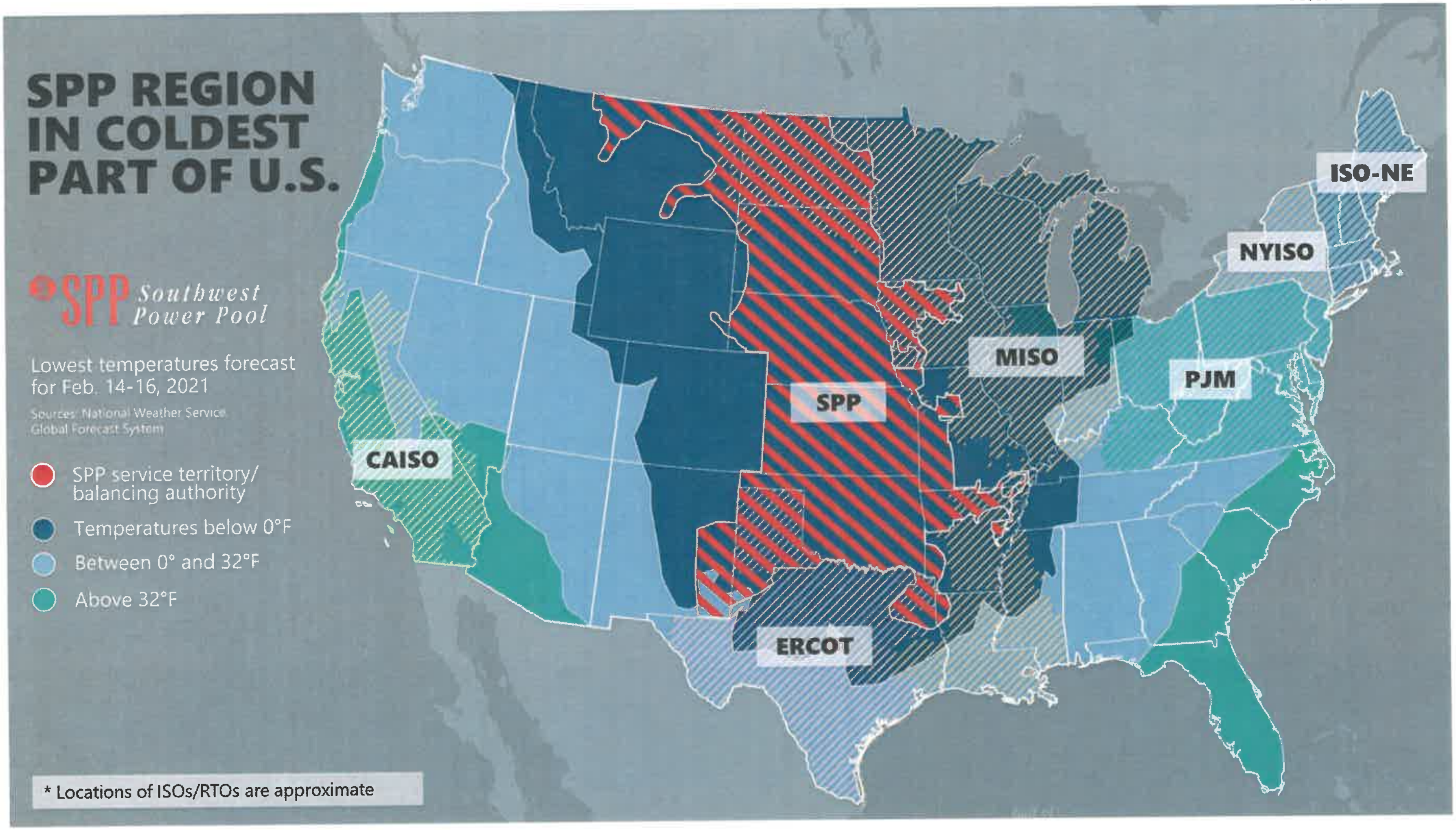
Collaboration reduced impact

Controlled, temporary interruptions prevented uncontrolled blackouts

Attachment 1



Attachment 1



Attachment 1

DRIVERS OF TEMPORARY SERVICE INTERRUPTIONS

1. Generation unavailability
   - Lack of fuel supply
   - Icing and extreme cold weather-related outages
2. Rapid reduction of energy imports
   - Related to transmission congestion
   - Tightening supply conditions in neighboring areas
3. Record winter energy consumption

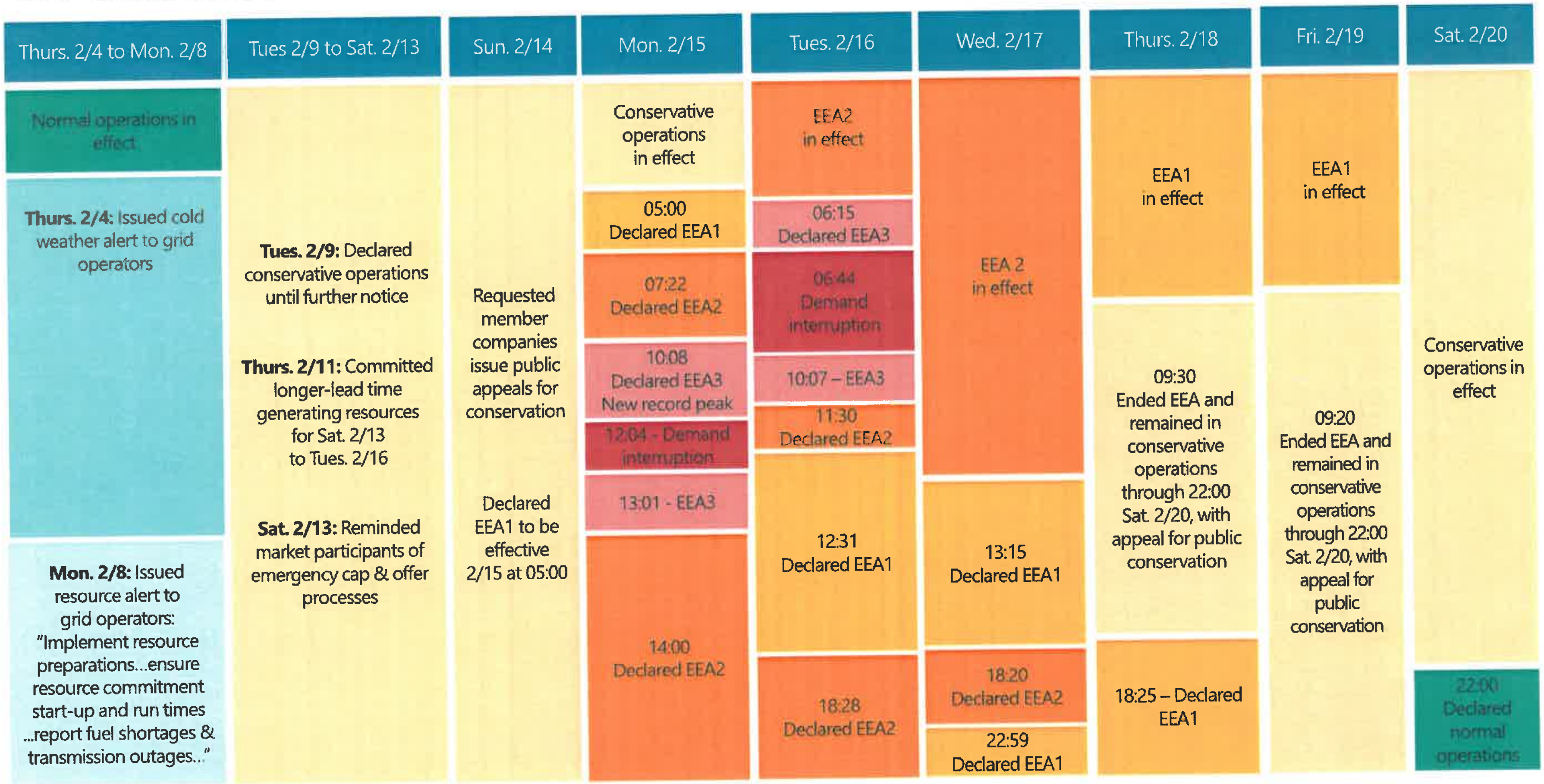
ADVANCE PREPARATIONS

- **Alerted** operators as conditions changed
- **Rescheduled** transmission & generation maintenance outages
- **Committed** generation that takes days to ramp up
- **Invited** members' communications & government affairs staff to briefings
- **Issued** public appeals to conserve power
- **Updated** regulators

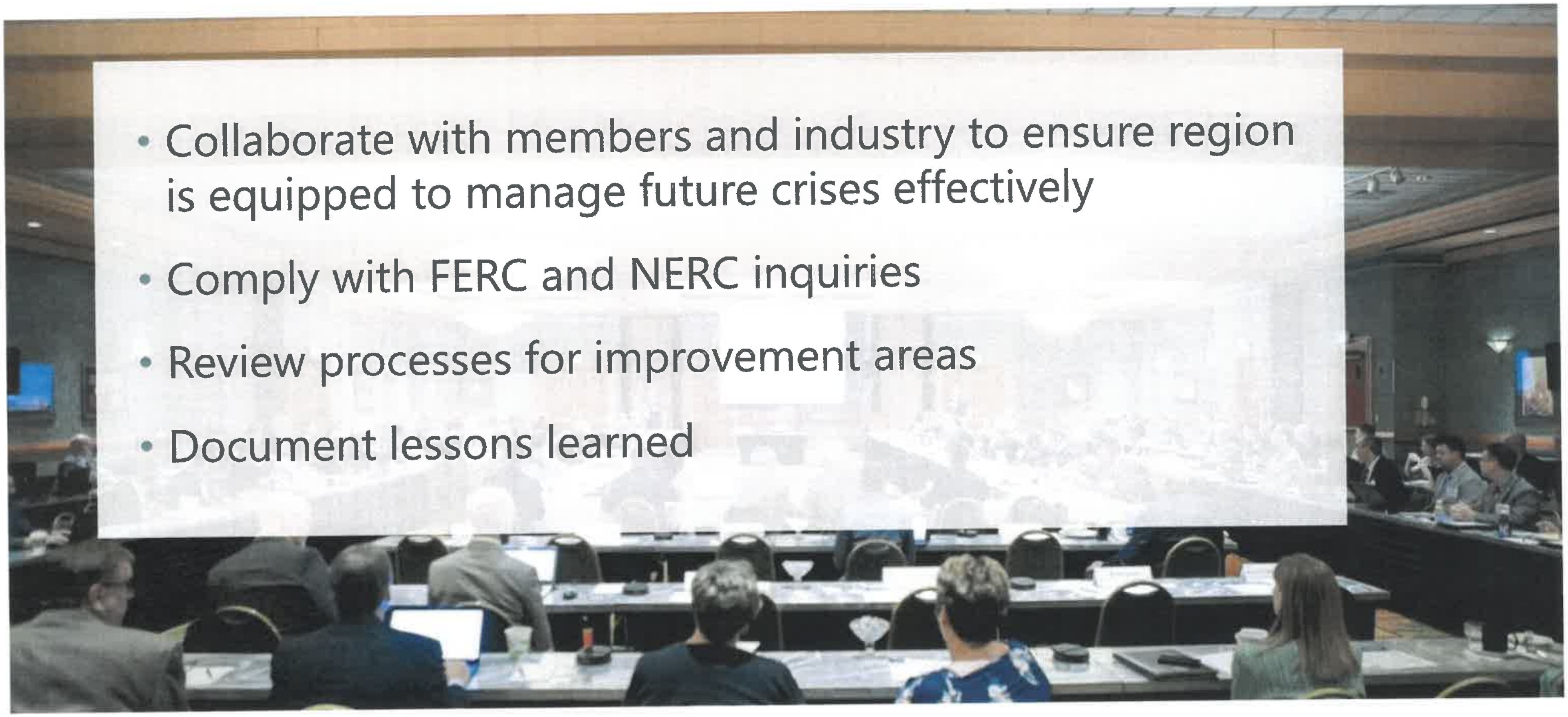
Attachment 1

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

Time blocks are not to scale



AFTER THE STORM



- Collaborate with members and industry to ensure region is equipped to manage future crises effectively
- Comply with FERC and NERC inquiries
- Review processes for improvement areas
- Document lessons learned

ESSENTIAL POINTS

Our large, interconnected network minimized interruptions

- SPP's transmission operators and neighboring regions all shared energy
- Helping each other in all directions minimized impacts to any one entity

Diverse generation mix gave flexibility during storm response

- Many types of generators provided power
- Because all fuel sources and generators are subject to problems in extreme weather, we needed many sources to call on

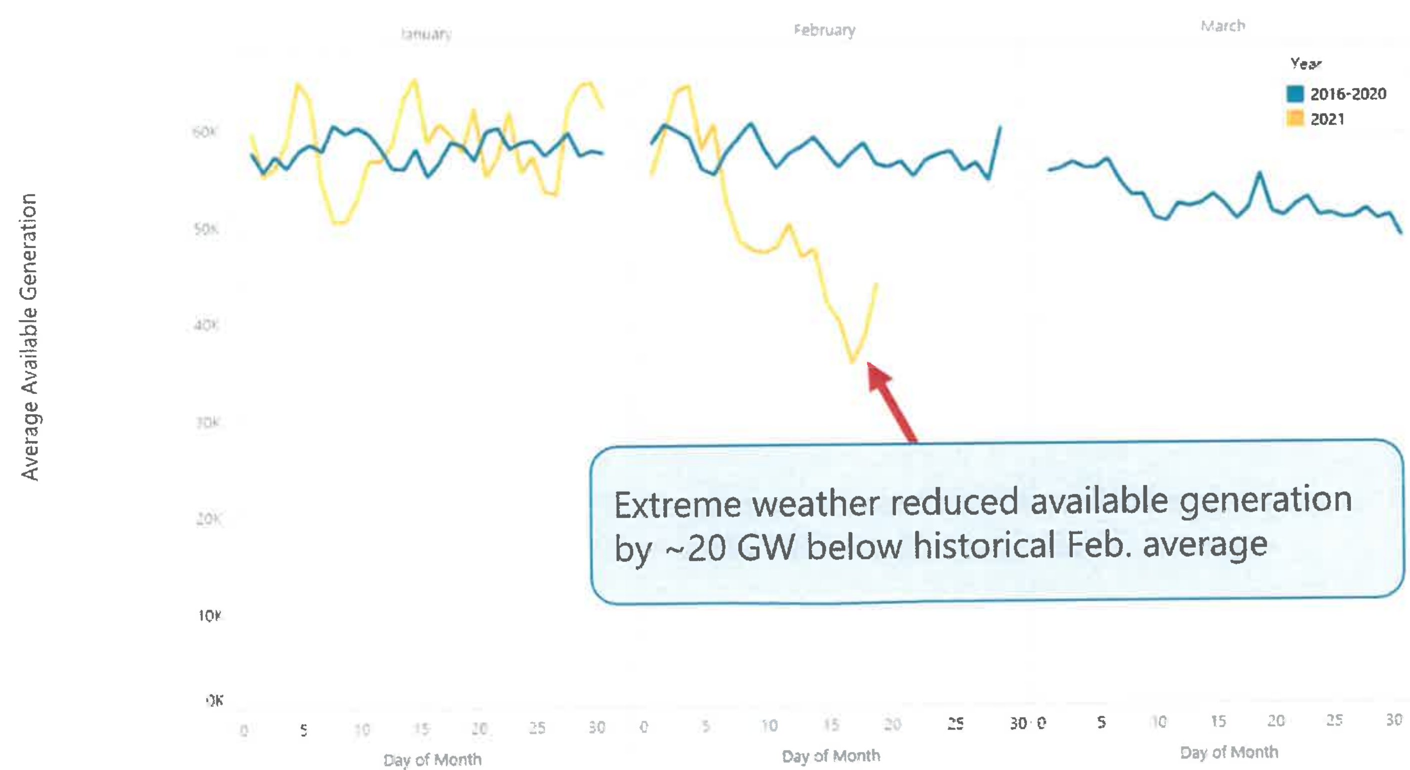
We avoided widespread, severe blackout by:

- Working closely with our neighbors
- Following NERC regulations and executing training scenarios
- Directing short curtailments to prevent grid from cascading out of control

OPERATIONS DATA

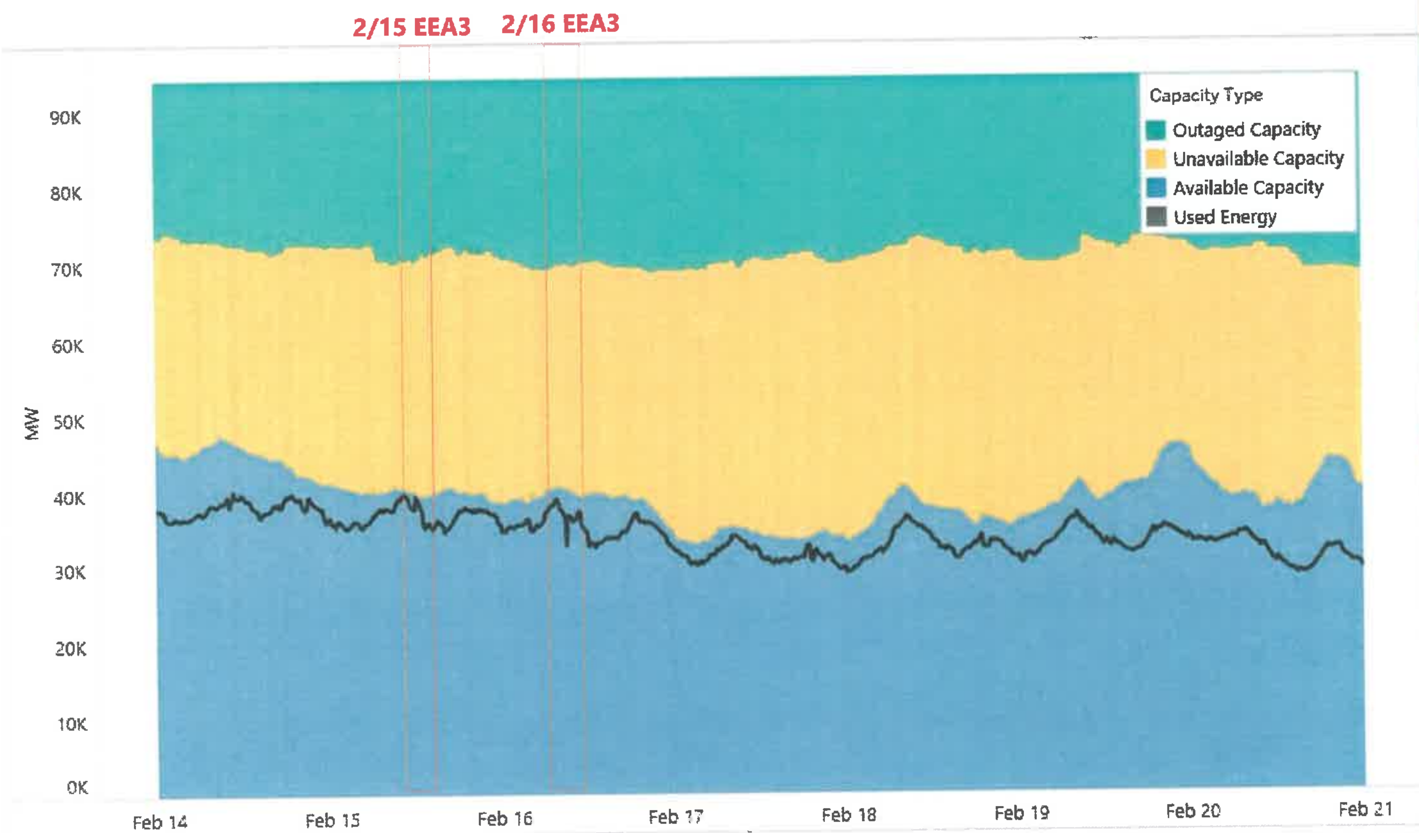
Attachment 1

AVAILABLE GENERATION IN SPP MARKET



Attachment 1

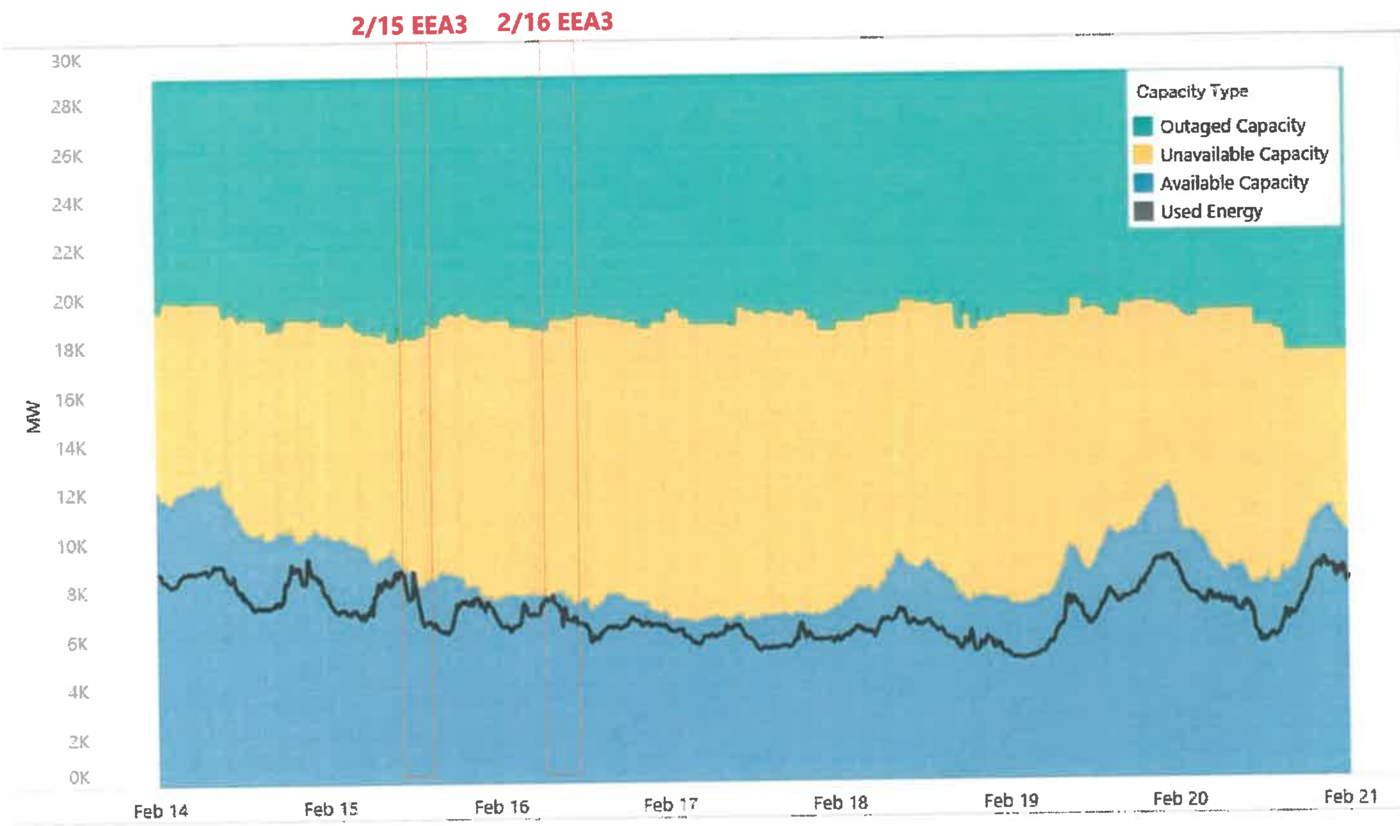
TOTAL GENERATING CAPACITY IN SPP



Appr. 42% of nameplate capacity and 65% of accredited capacity in SPP was available during EEA3 periods

Attachment 1

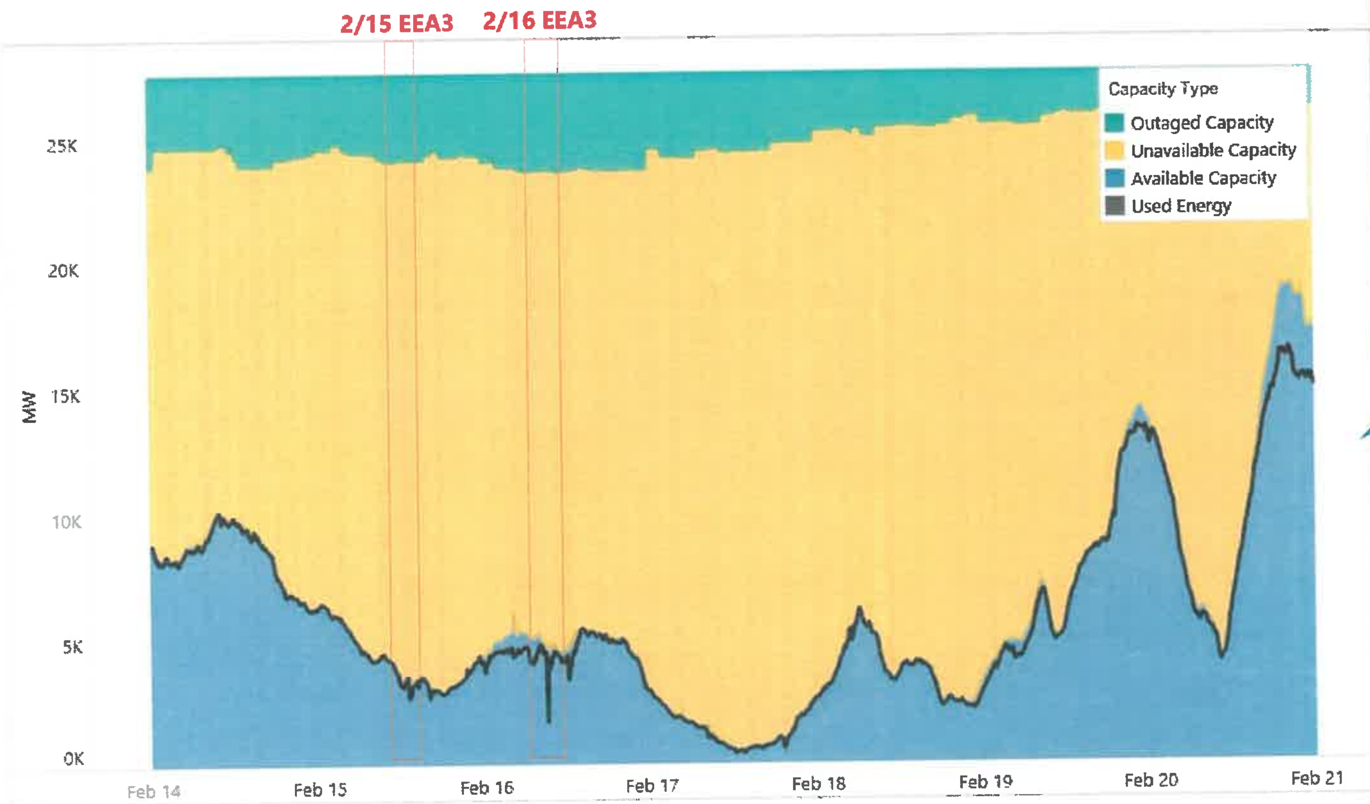
TOTAL GENERATING CAPACITY – OKLAHOMA



Appr. 26-28% of nameplate capacity in OK was available during EEA3 periods

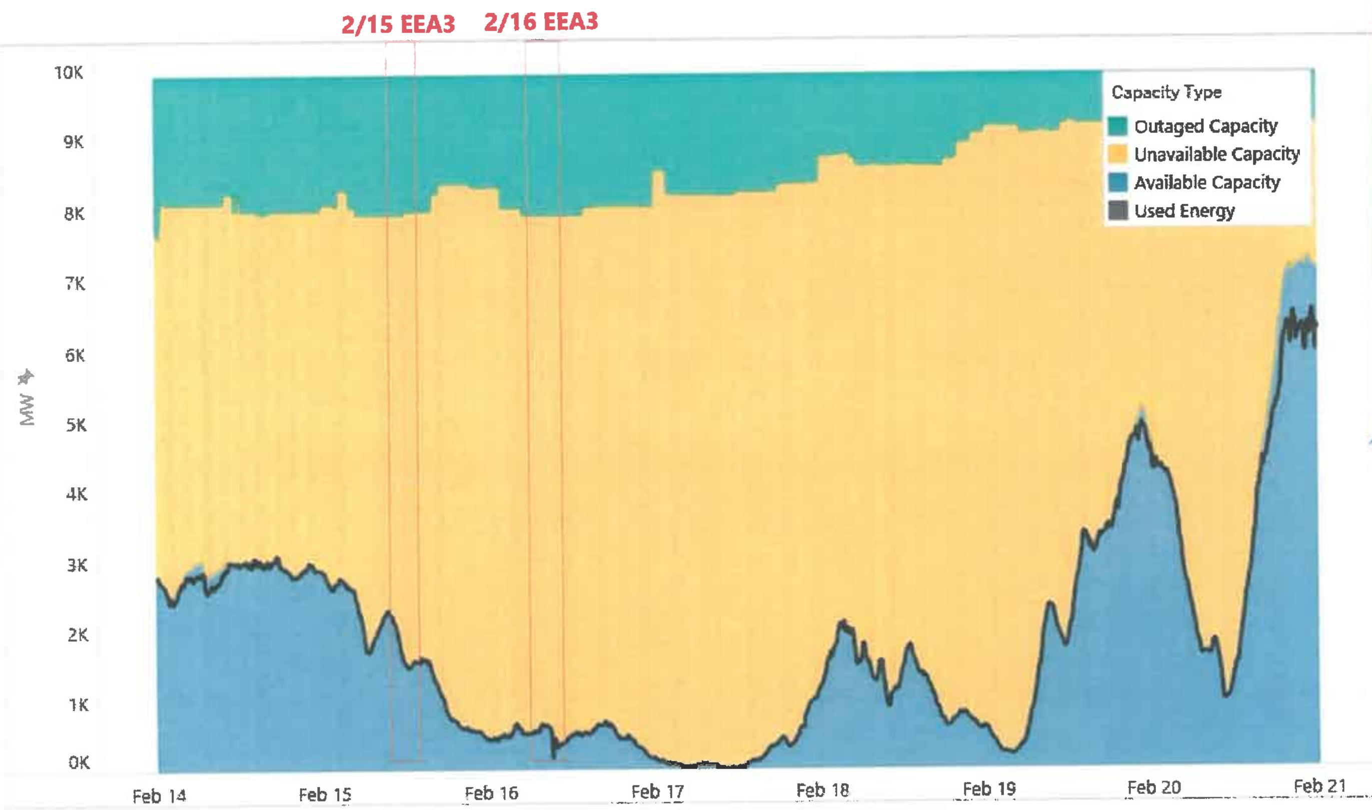
Attachment 1

GENERATING CAPACITY IN SPP – WIND



For wind generation in SPP, 3.5-4.6% of nameplate capacity and 95-123% of accredited capacity was available during EEA3 periods

GENERATING CAPACITY – WIND – OKLAHOMA

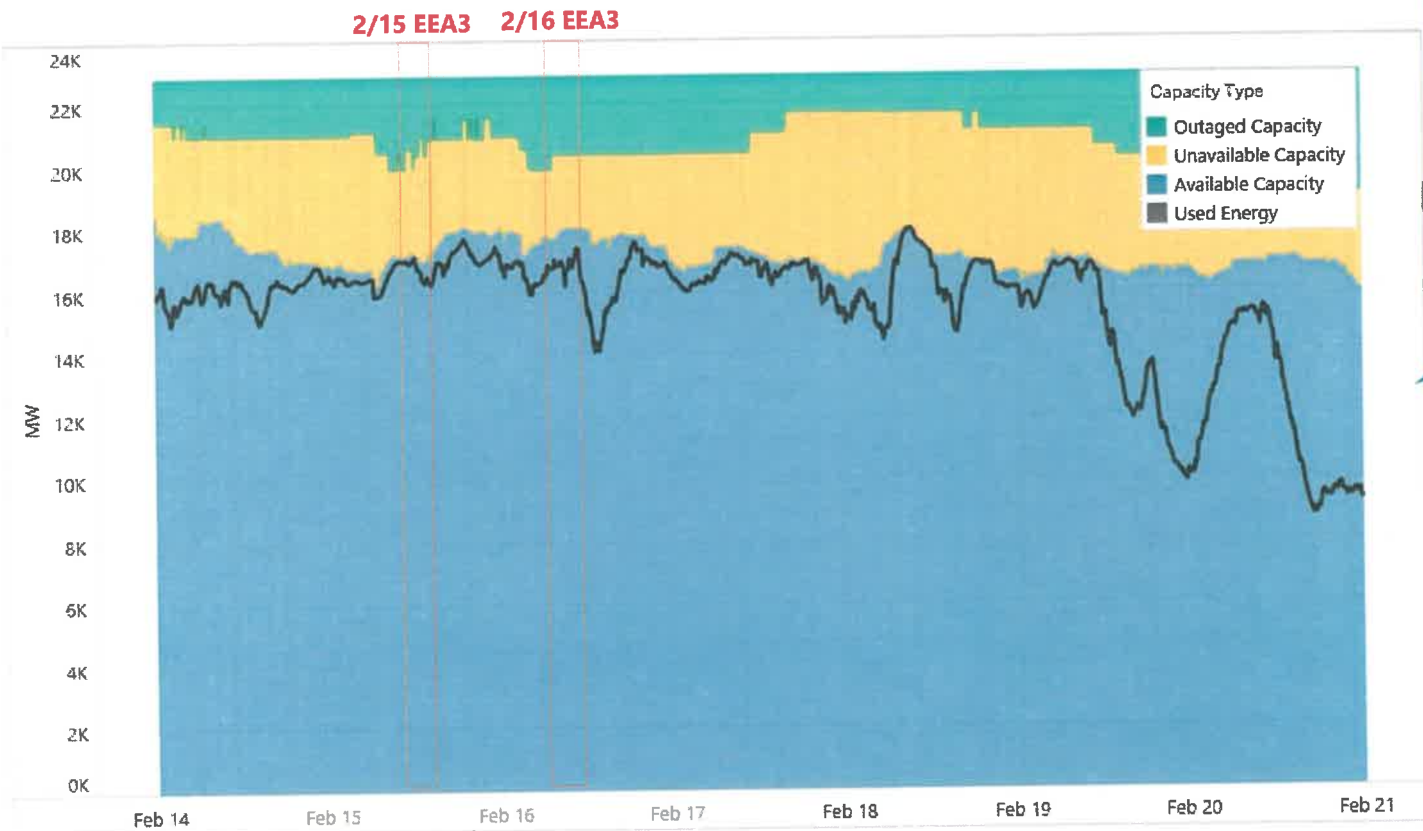


During the EEA3 events, wind in OK contributed nearly half of SPP's wind on the 15th but dropped to about 12% of SPP's wind on the 16th

SPP

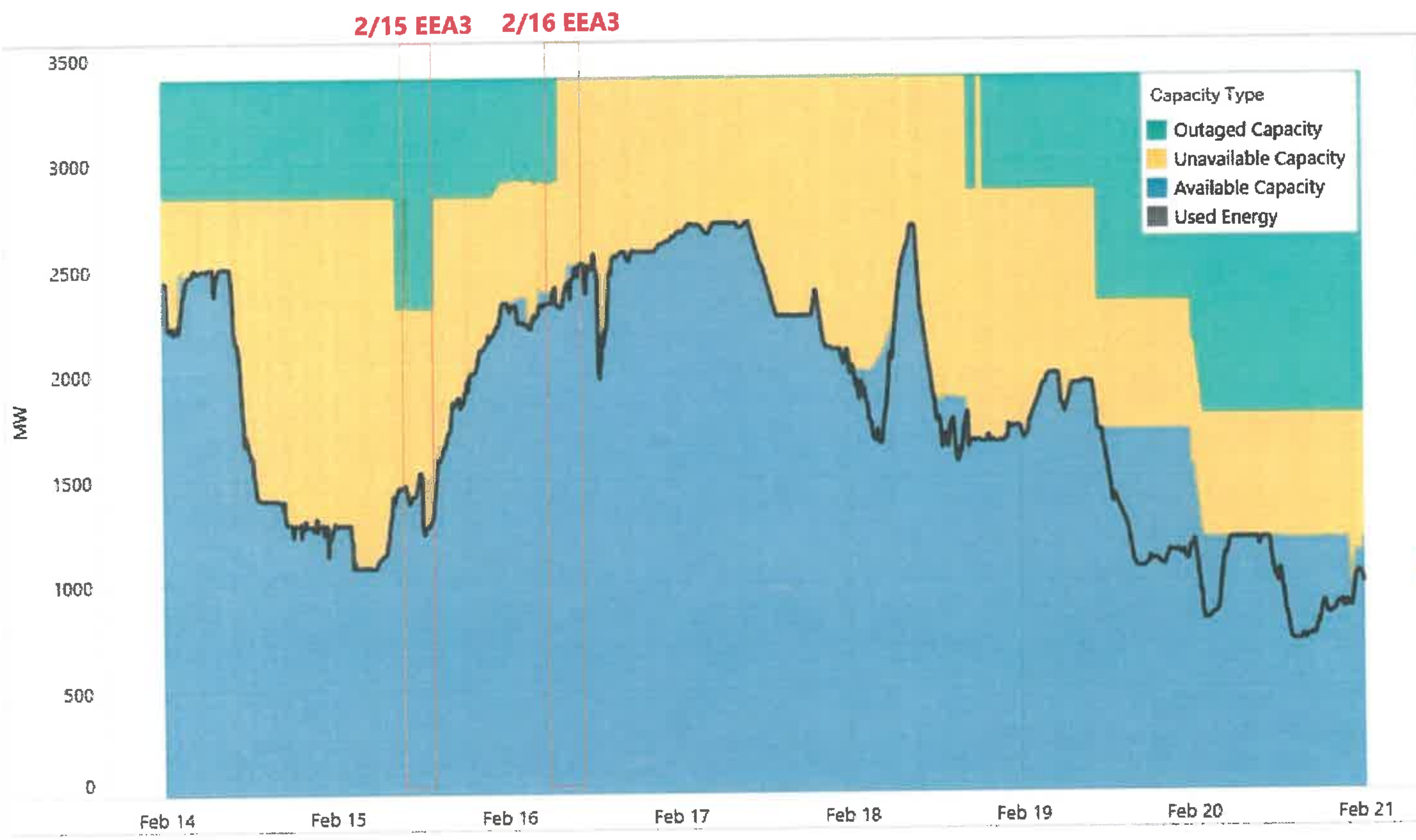
Attachment 1

GENERATING CAPACITY IN SPP – COAL



For coal generation in SPP, 71-75% of accredited capacity was available during EEA3 periods

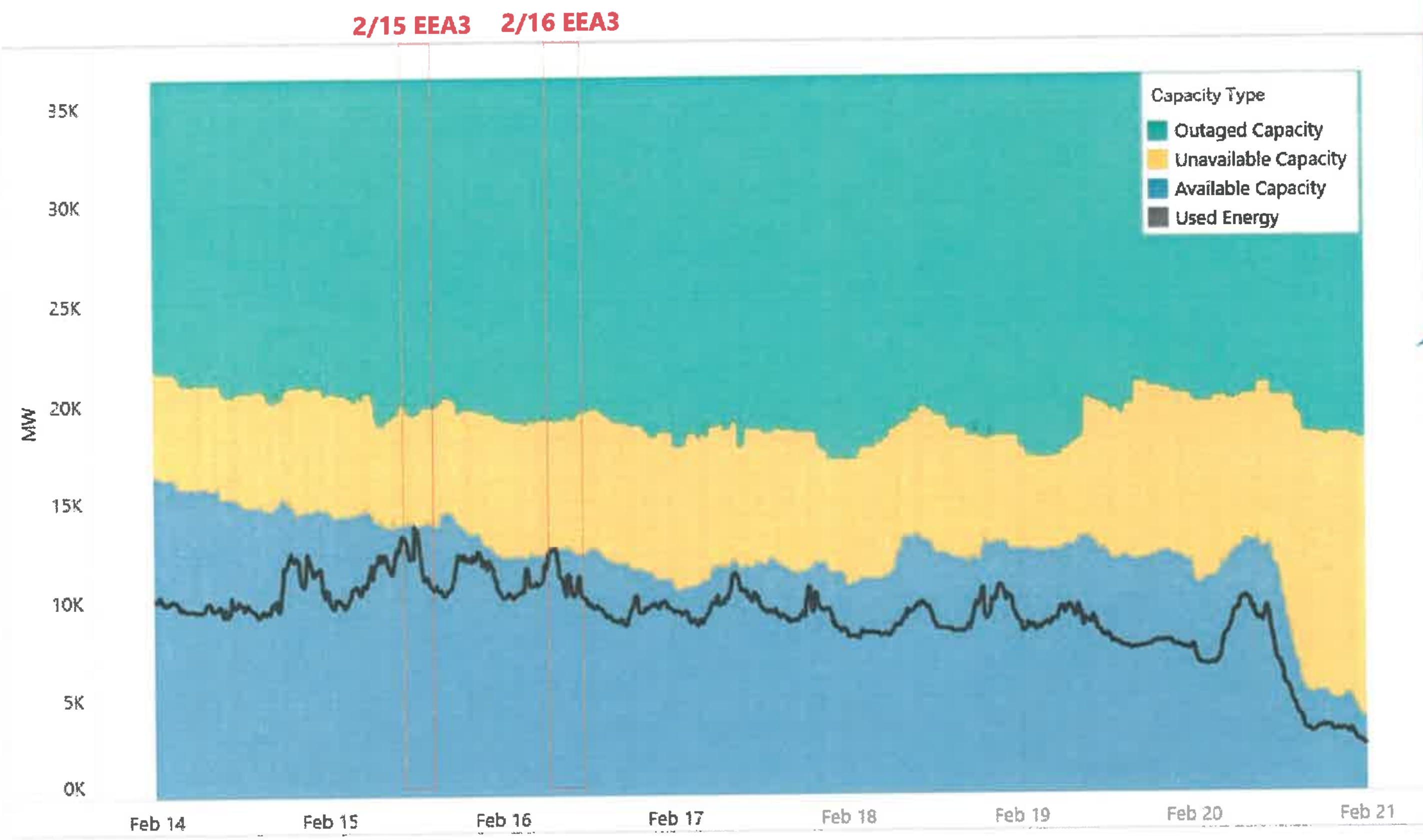
GENERATING CAPACITY – COAL – OKLAHOMA



During the EEA3 events, coal gen. in OK supplied 8% of available coal gen in SPP on the 15th and 14% of available coal gen in SPP on the 16th

Attachment 1

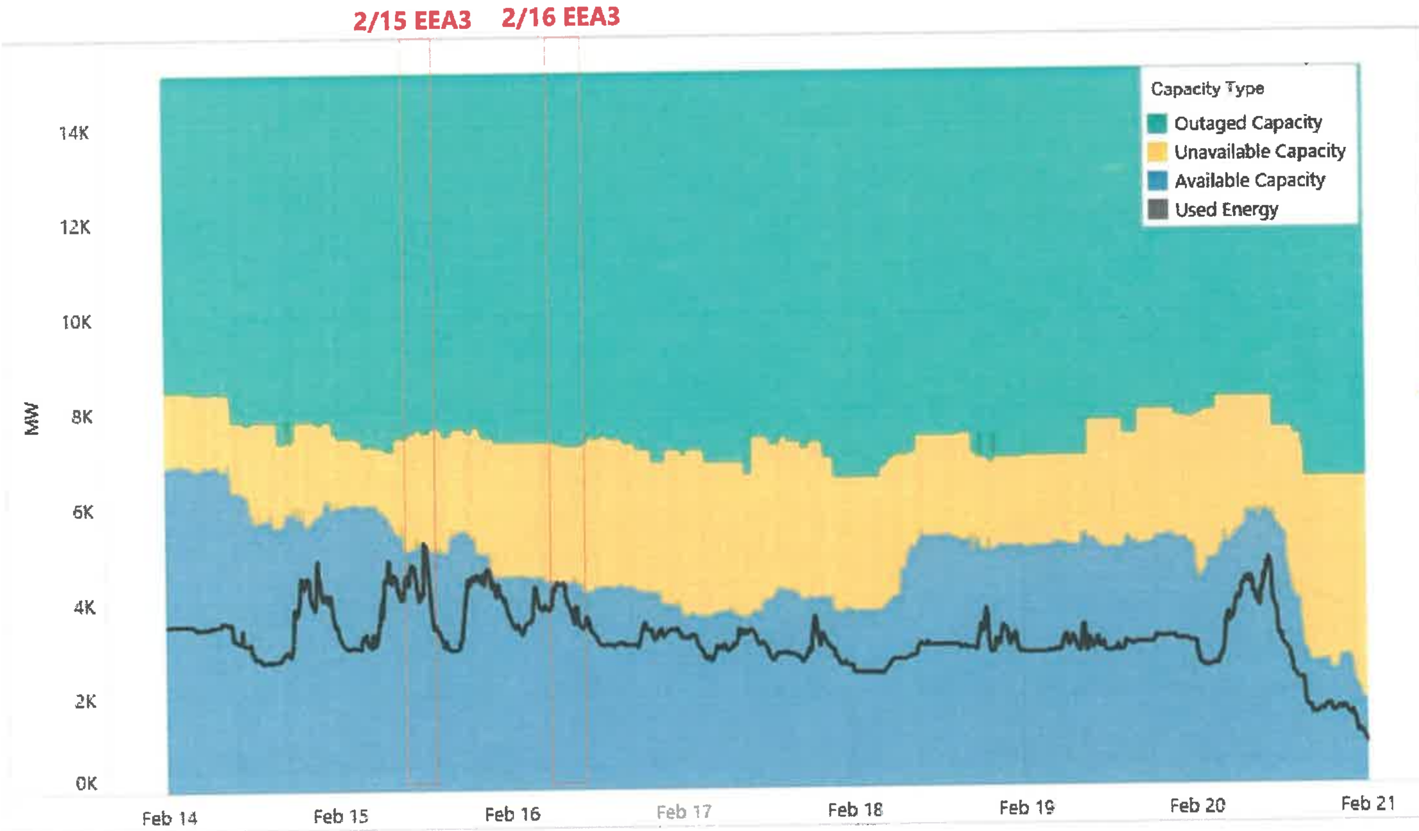
GENERATING CAPACITY IN SPP – GAS



For gas generation in SPP, 45-50% of accredited capacity was available during EEA3 periods

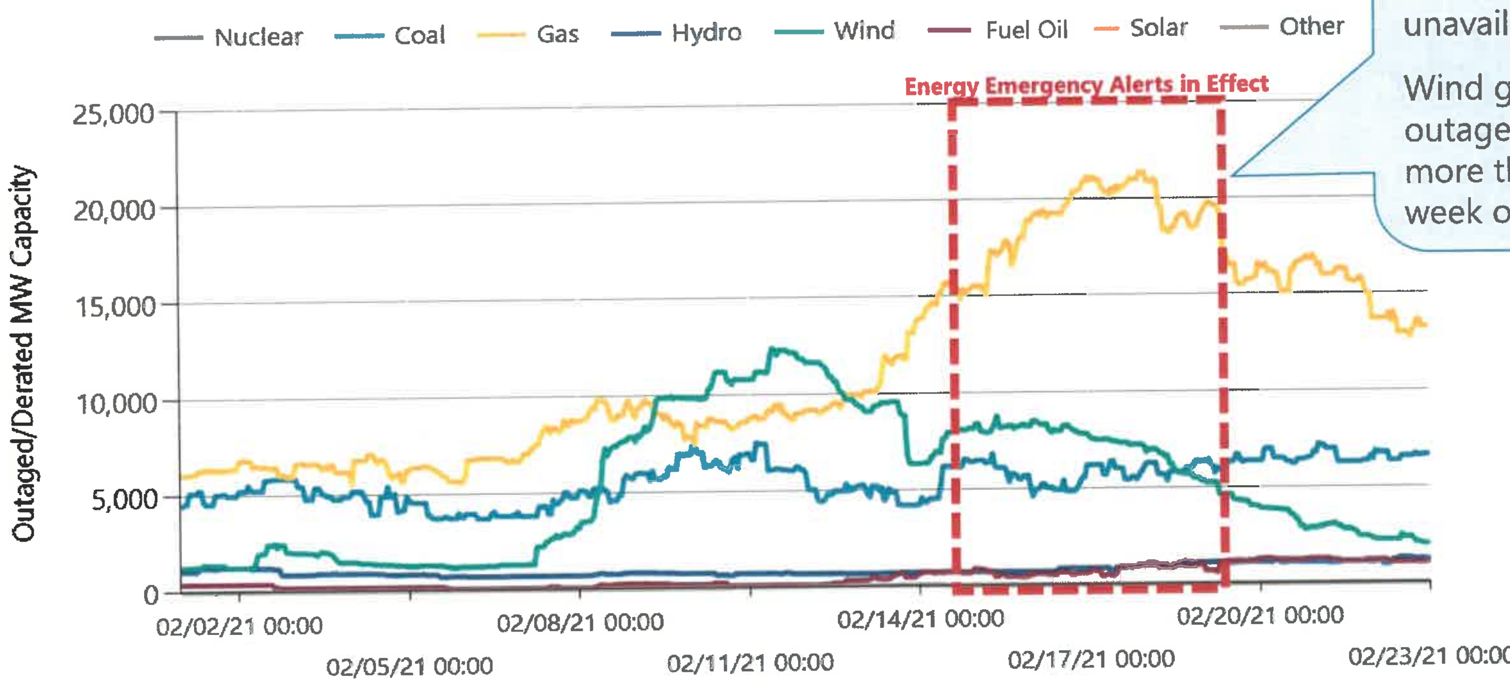
Attachment 1

GENERATING CAPACITY – GAS – OKLAHOMA



During the EEA3 events, gas gen. in OK supplied 36% of available gas gen in SPP on both the 15th and 16th

GENERATING CAPACITY OUTAGES



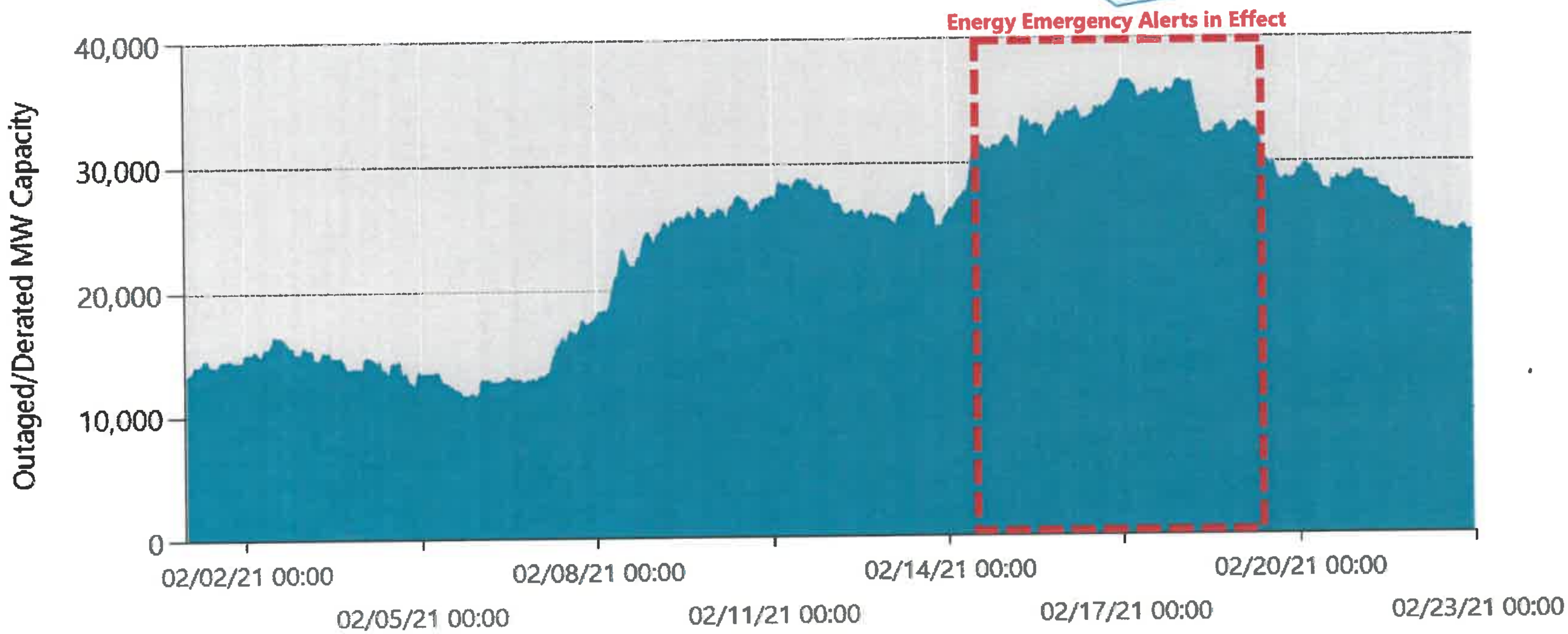
During peak conditions, gas generation contributed to ~60% of total unavailability

Wind generation outages ~5x more than first week of Feb.

TOTAL GENERATION OUTAGES

Up to 35,000 MW of generating capacity unavailable to meet demand

Nearly 2.5x more outages than first week of Feb.

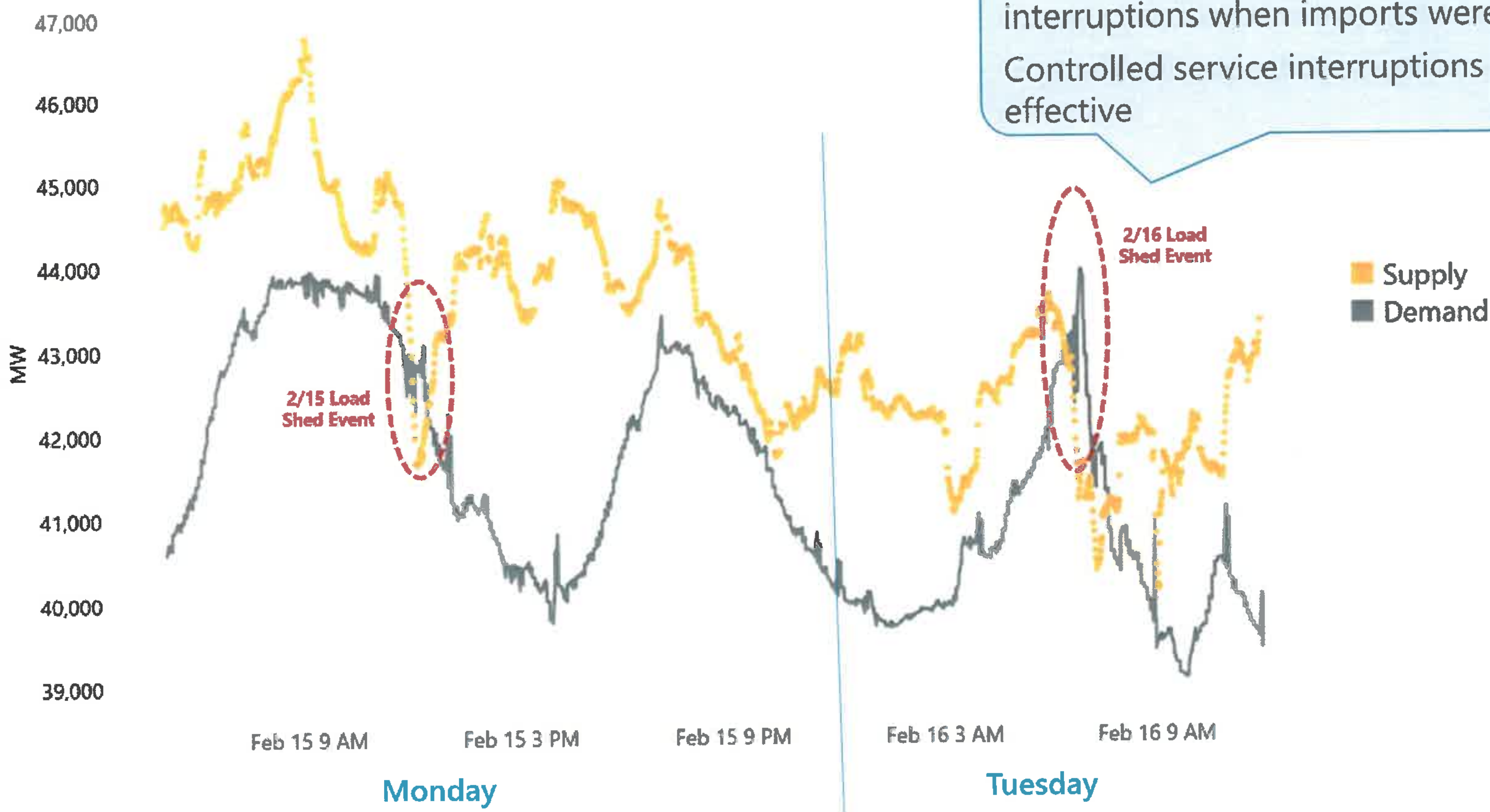


Attachment 1

GENERATION SUPPLY VS. DEMAND

SPP directed controlled service interruptions when imports were curtailed

Controlled service interruptions were effective

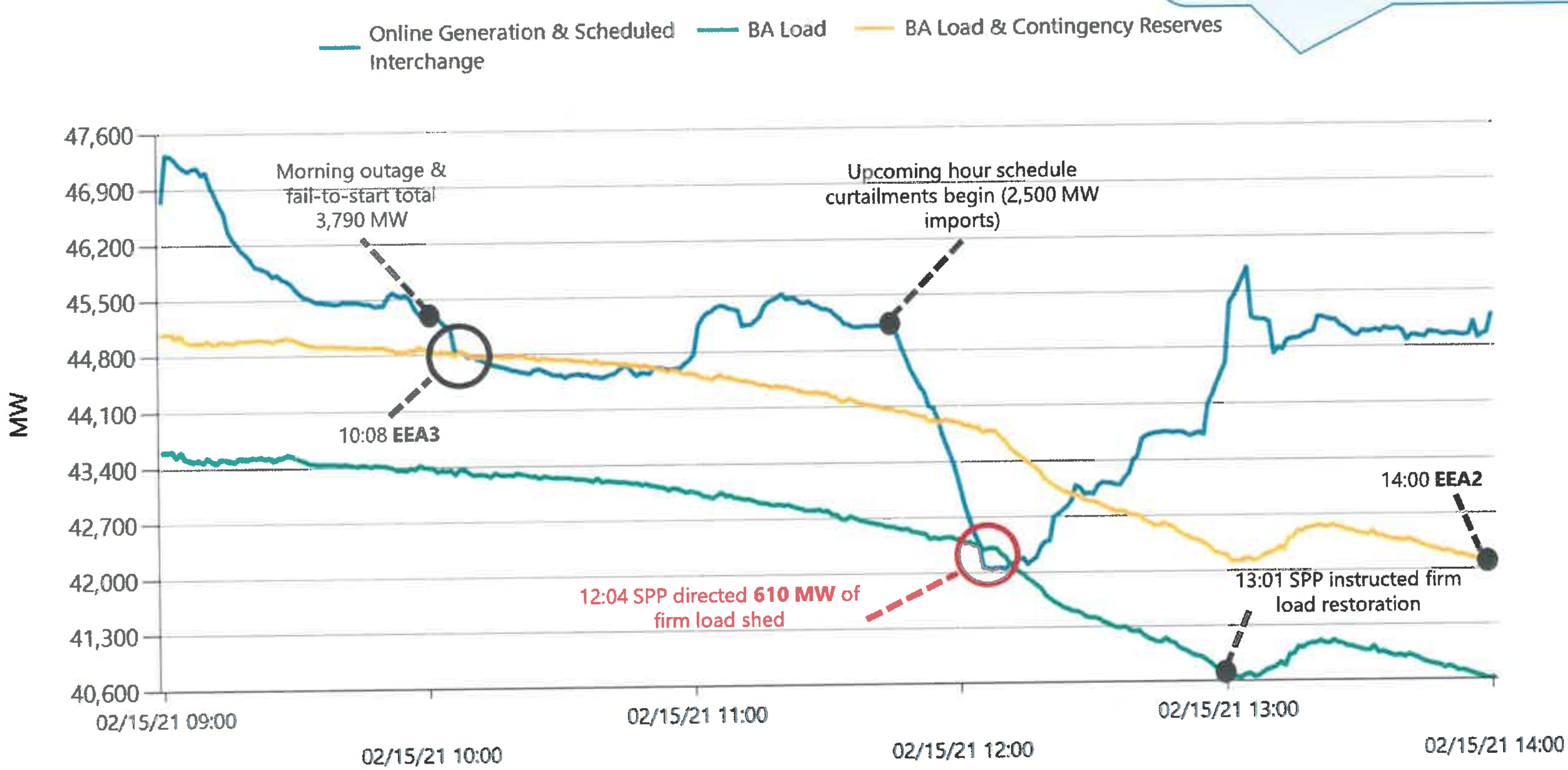


Attachment 1

2/15 LOAD & ONLINE GENERATION WITH NET ENERGY IMPORTS

SPP issued EEA3 when unable to maintain required reserves

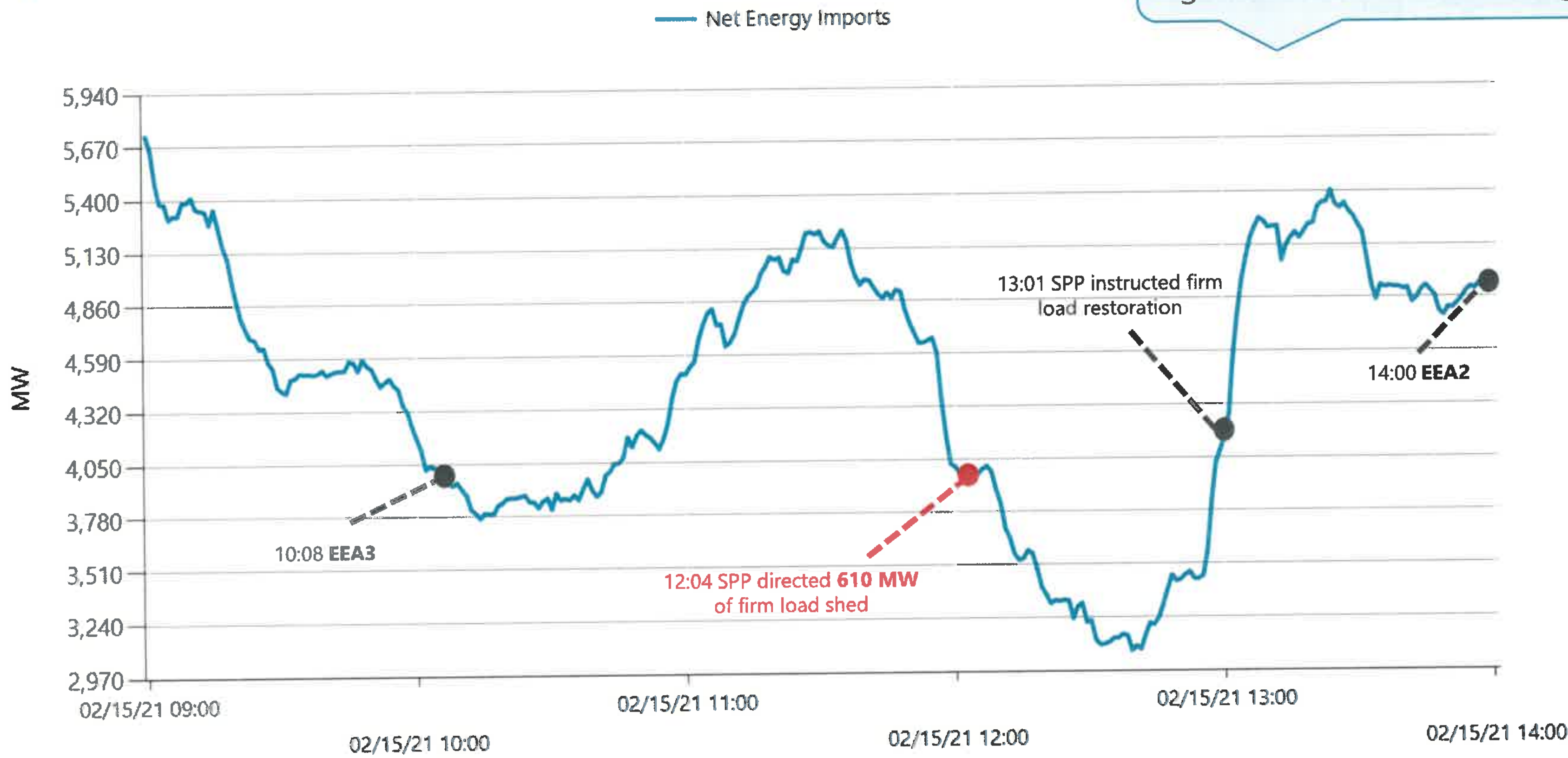
Reduced imports created supply vs. demand imbalance



Attachment 1

2/15 NET ENERGY IMPORTS

At times, SPP was importing significant amounts of energy

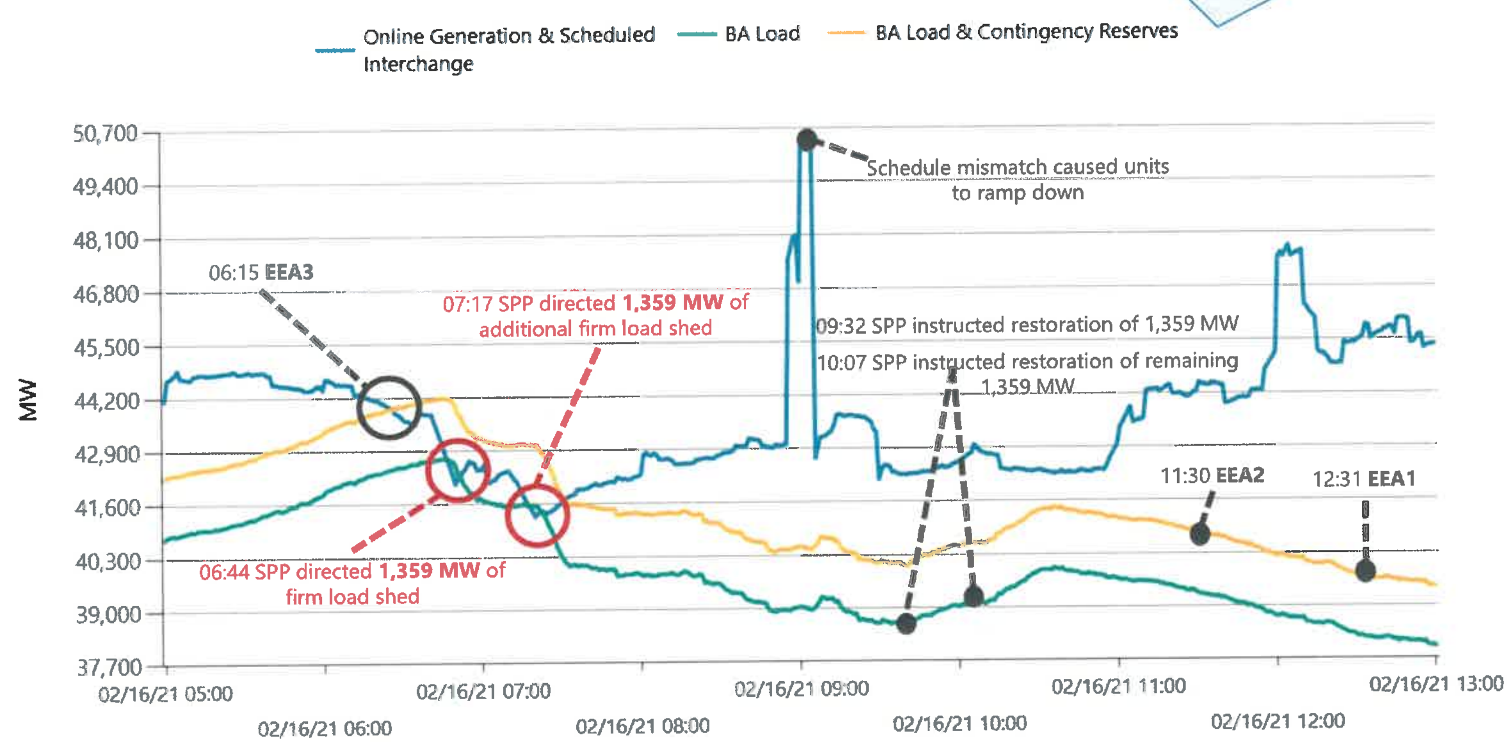


SPP

Attachment 1

2/16 LOAD & ONLINE GENERATION WITH NET ENERGY IMPORTS

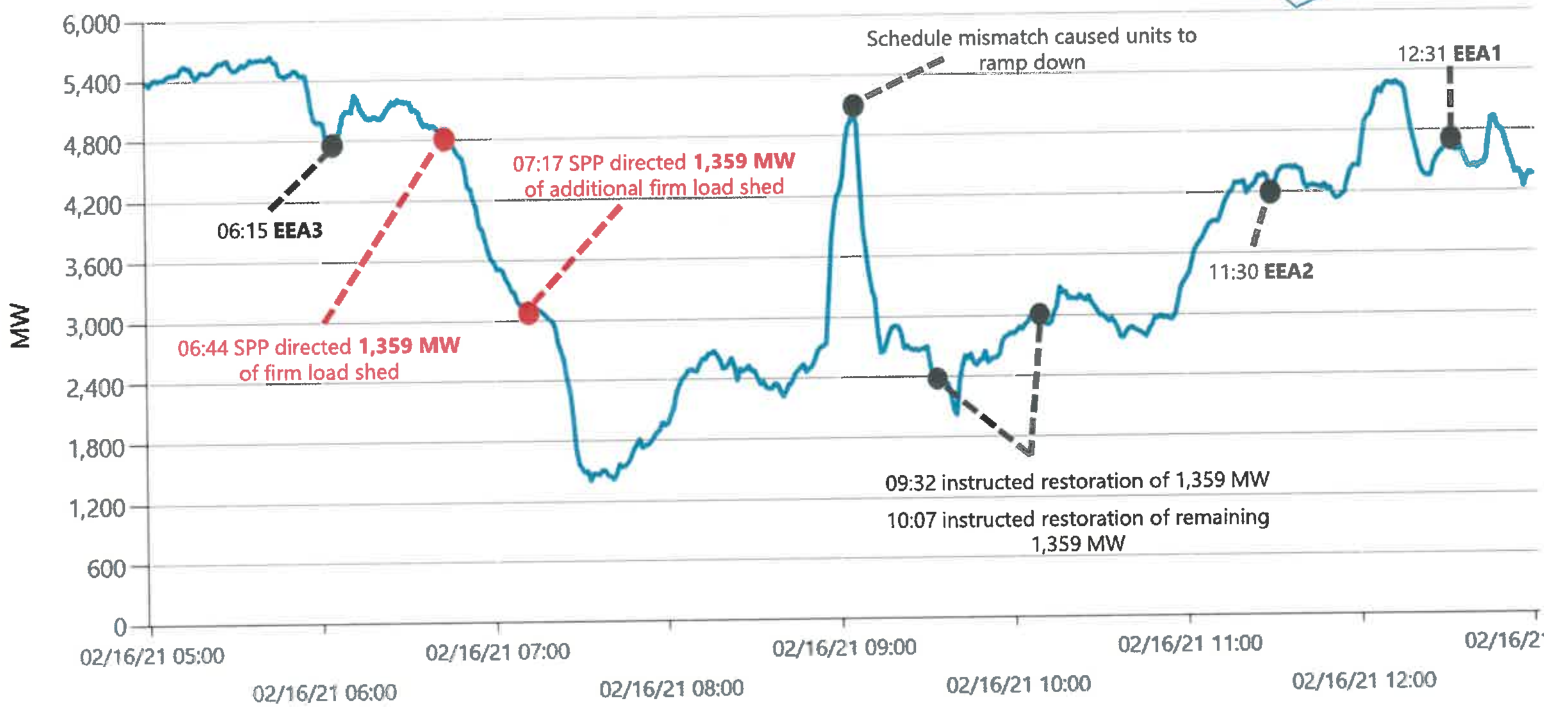
SPP issued EEA3 when unable to maintain required reserves, caused by dwindling supply and higher demand



Attachment 1

2/16 NET ENERGY IMPORTS

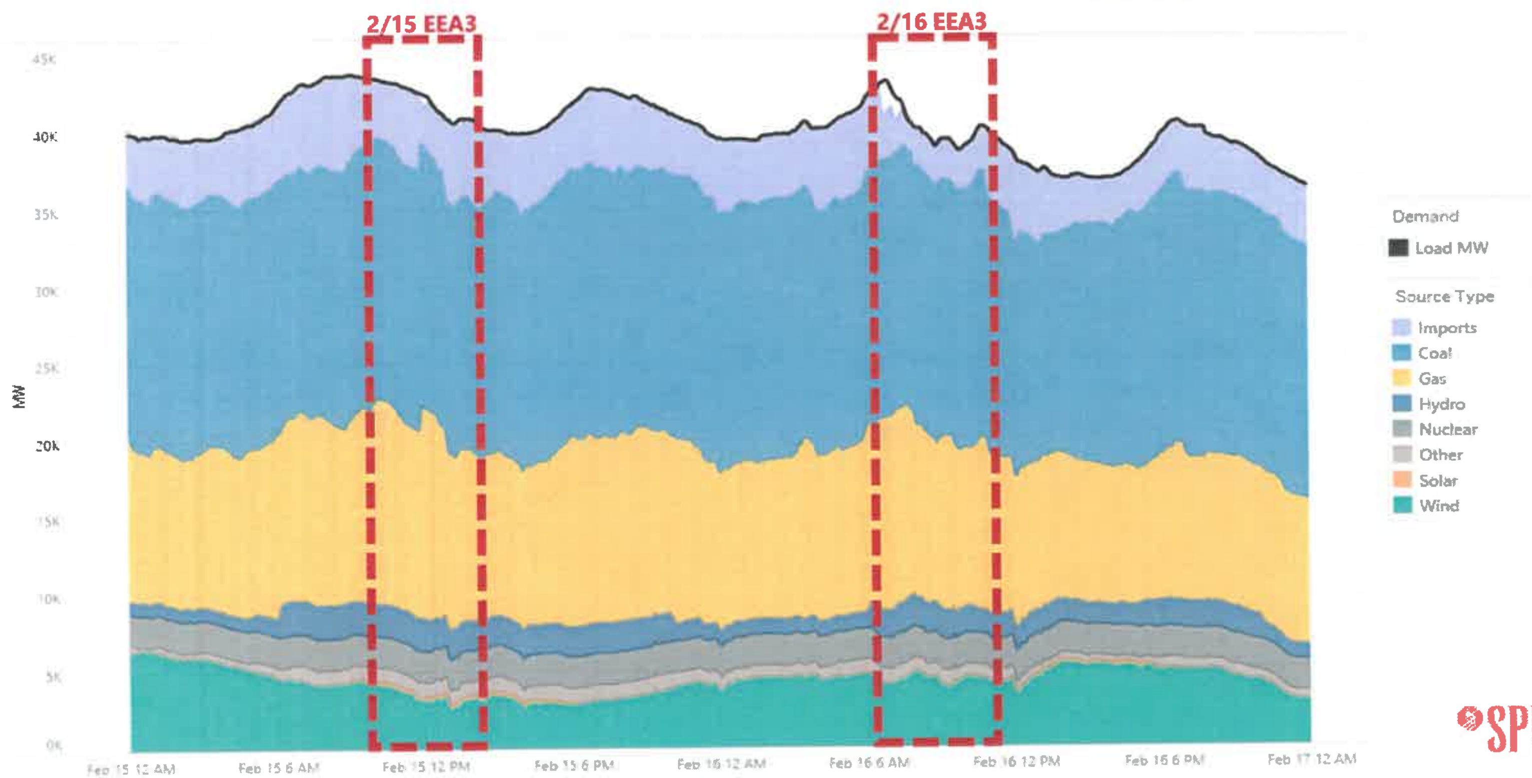
At times, SPP was importing significant amounts of energy, although less than what had been available day prior



Attachment 1

ENERGY THAT MET DEMAND IN REAL-TIME MARKET

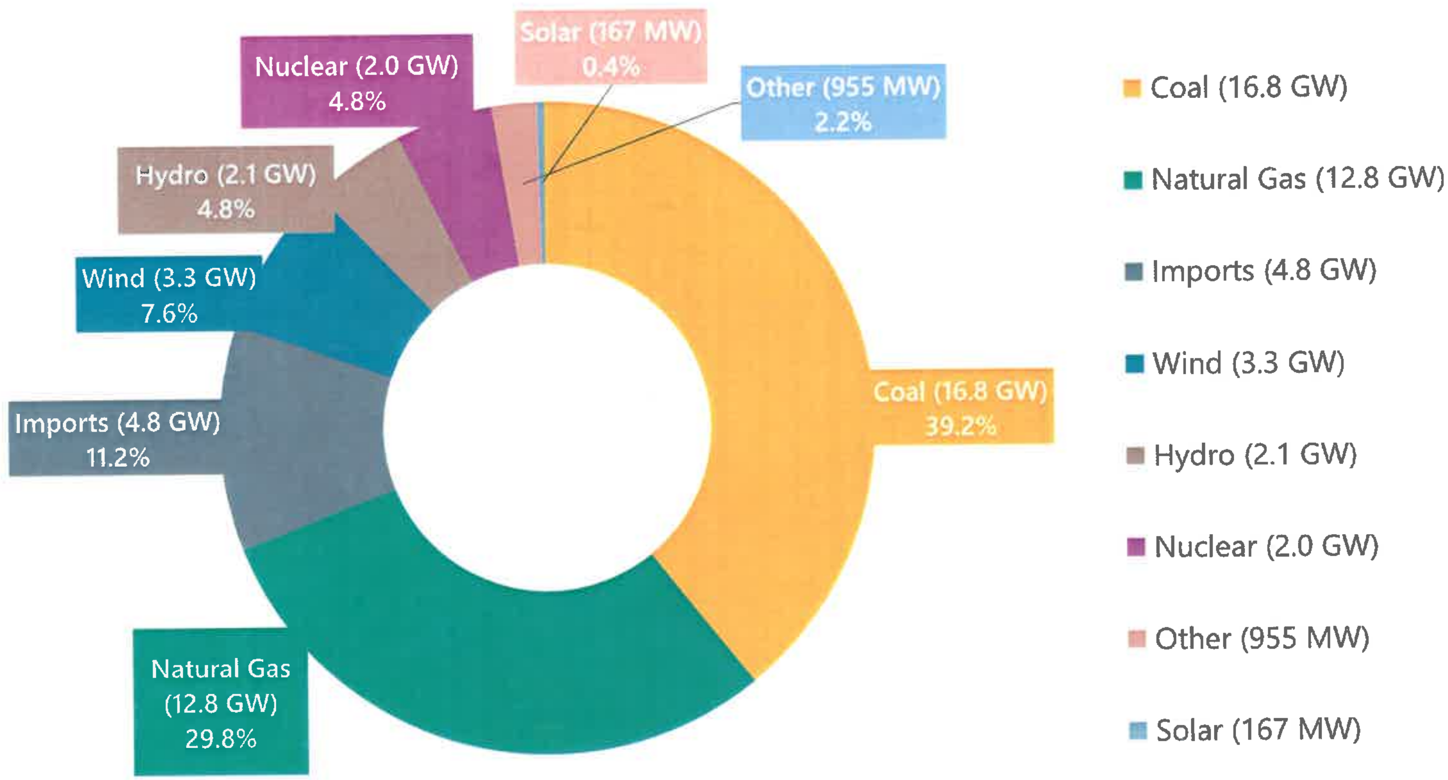
SPP relied on energy from multiple sources, including imports from neighbors



SPP

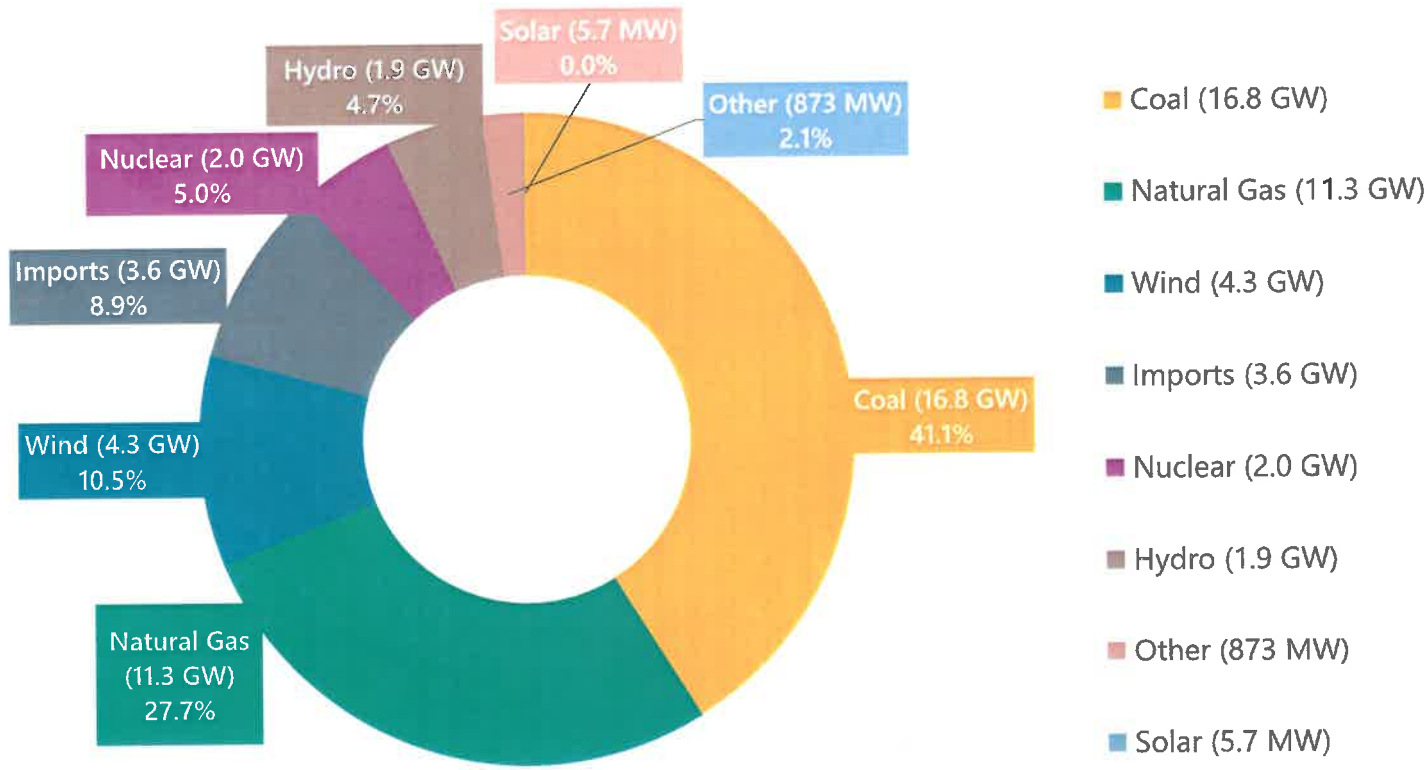
Attachment 1

AVERAGE SUPPLY MIX
DURING FEBRUARY 15 CONTROLLED SERVICE INTERRUPTIONS



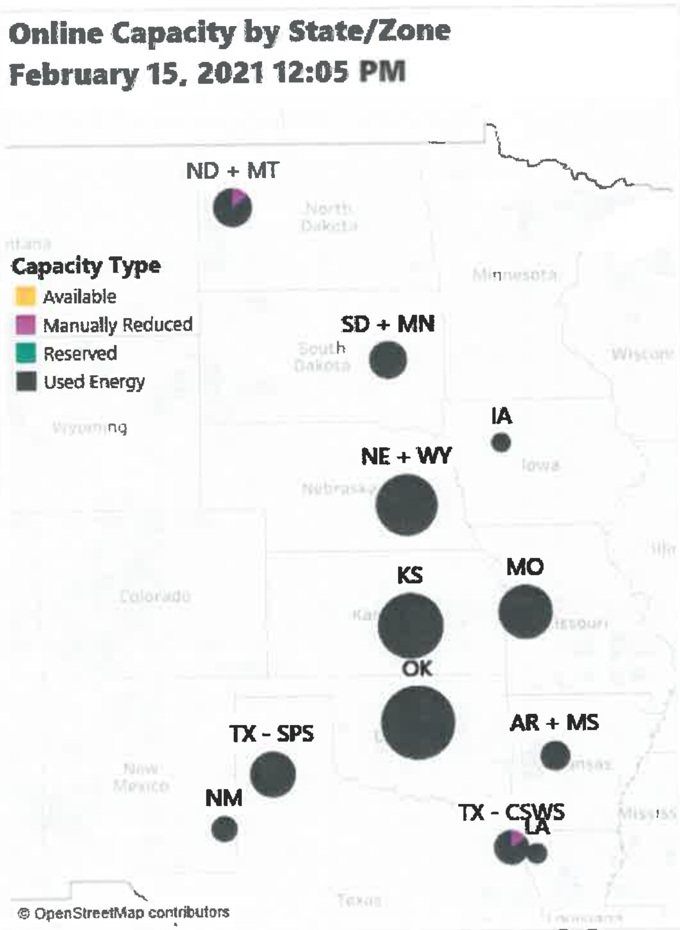
Attachment 1

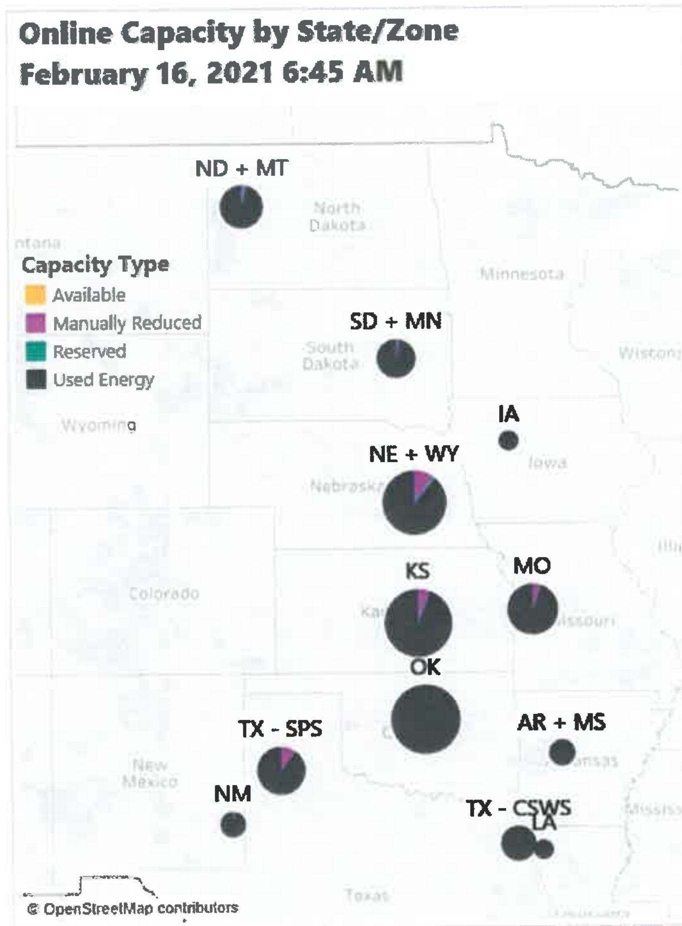
AVERAGE SUPPLY MIX
DURING FEBRUARY 16 CONTROLLED SERVICE INTERRUPTIONS



SPP

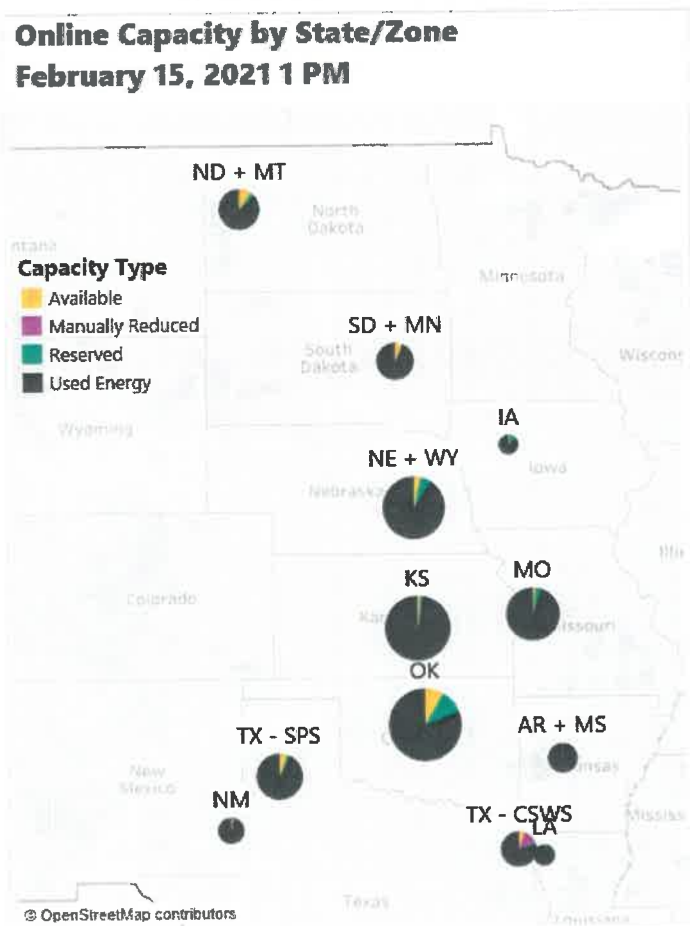
SPP CAPACITY – BEGINNING OF DEMAND REDUCTION

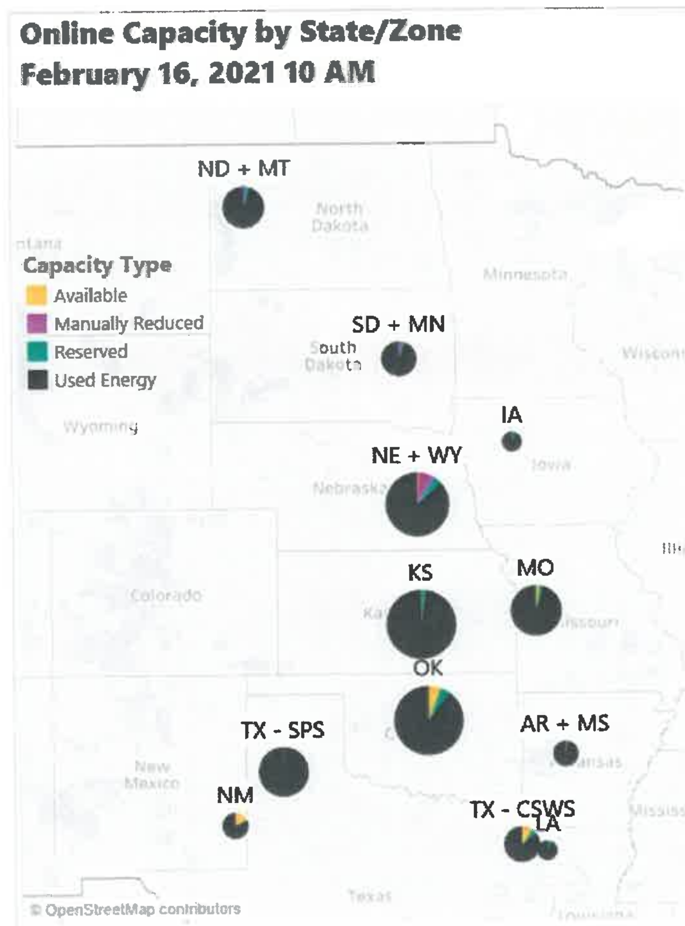




Attachment 1

AVERAGE SPP CAPACITY – DURING HOUR OF LOAD RESTORATION



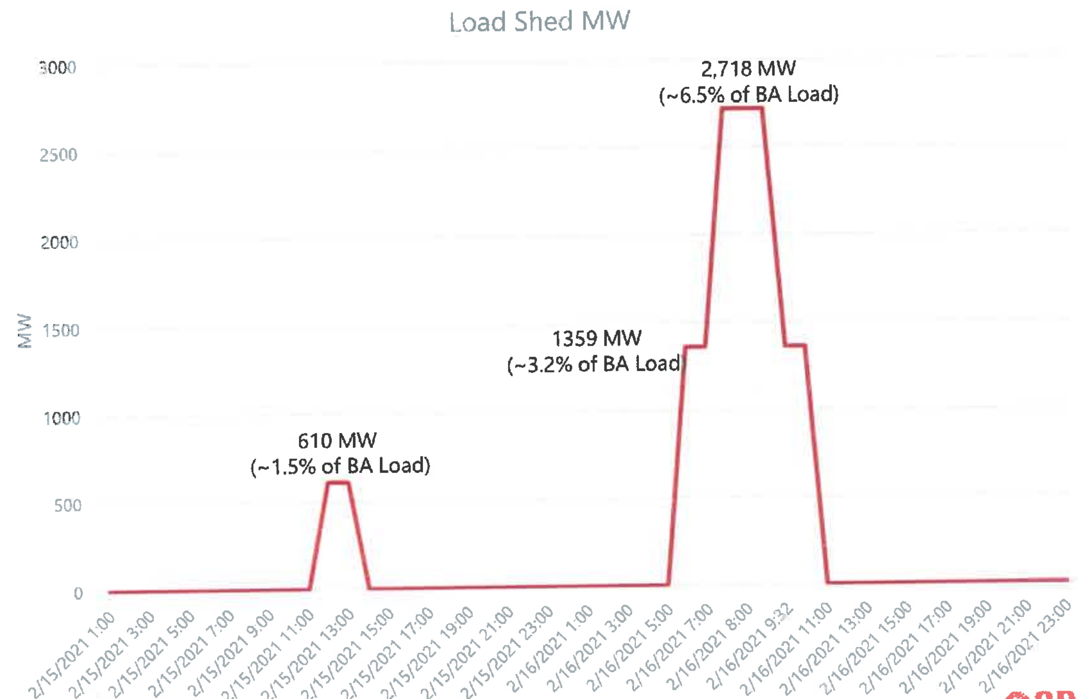


Attachment 1

INTERRUPTIONS BY ENTITY

Participating Entity	% of MW
CSWS	16.8
WAPA	13.5
SPS	12.4
OKGE	12.4
KCPL	9.68
WR	8.49
NPPD	6.57
OPPD	4.6
WFEC	3.78
GRDA	2.22
SECI	2.22
EDE	2.19
LES	1.36
SPRM	1.22
KACY_N	0.92
CBPC	0.83
INDN	0.38
SPA	0.28
TSGT	0.13
SPP Total	100%

Directed interruptions allocated to transmission operators on pro-rata basis



Notes: 1) Transmission operators with significant load in Oklahoma are highlighted. 2) CSWS includes PSO and SWEPCO. 3) Allocation percentages are predetermined based on pro-rata share of previous winter season's energy consumption

SPP

CONTACT SLIDE

Communications

Please feel free to contact us at communication@spp.org if you need help with the PPT, need modifications or would like to add a slide to the template.

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE (ERPTF)

TESTIMONY QUESTIONS

ELECTRIC UTILITIES

SOUTHWESTERN ELECTRIC POWER COMPANY

ERPTF – Question No. 1

DATE REQUESTED: **April 9, 2021**

DATE OF RESPONSE: **May 7, 2021**

INFORMATION REQUESTED:

Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

a. In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event? What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?

b. Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future? Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?

c. What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?

RESPONSE:

1a. The Southwest Power Pool (SPP) region experienced extreme cold temperatures during the unprecedented February 2021 winter storm event. These extreme conditions resulted in extremely high February demand for electricity. It has been widely publicized that these temperatures led to freezing conditions which interrupted gas supply across the SPP footprint during this time of extreme demand, and in turn caused many gas-fired units to be curtailed or forced into an outage situation due to limited fuel supply. While SWEPCO's generation fleet is comprised of varied sources, including renewable generation, natural gas and coal, the extreme conditions also adversely impacted SWEPCO's solid-fuel generation, as unit operations were impacted by equipment and instrumentation that were disabled due to harsh conditions. Across the 14-state SPP region, resource diversity also played a key role in mitigating the potential impact of the winter storm event. In addition, the SPP over time has done a good job of managing the reserve margin.

From a Transmission Operator perspective, AEP Transmission Operations worked closely with SPP before and during the event to execute operating instructions aimed at adjusting the load on the Transmission System in order to maintain stability. The actions taken during the event are included in the annual System Operator capacity deficiency training conducted by SPP and AEP. This training provides the System Operators with an understanding of the actions that need to be taken in a capacity deficiency event.

The mitigation strategies that were in effect at the time of the winter weather event are those strategies that SWEPCO is required to maintain at all times by NERC and SPP. The various operating levels required are set out in the table below.

BALANCING AUTHORITY (BA) ALERT LEVELS

Alert levels defined by SPP operating plans

Normal Operations	SPP has enough generation to meet demand, has available reserves and does not foresee extreme or abnormal reliability threats
Weather alert	SPP expects extreme weather in its reliability coordination service territory
Resource alert	SPP's BA area expects severe weather conditions, significant outages, wind-forecast uncertainty and/or load-forecast uncertainty with potential to impact total capacity.
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Maximum emergency generation notification	SPP foresees the need to use emergency ranges of resources for a certain hours.

Alert levels defined* by NERC EOP-011-1

Energy Emergency Alert (EEA) Level 1	**All available generation resources in use** • All generation is committed, and there is concern about maintaining required reserves for BA • Non-firm wholesale energy sales curtailed.
EEA Level 2	**Load management procedures in effect** • BA is no longer able to provide its expected energy requirements and is energy deficient • Operating plan implemented, including public appeals and demand response • BA is still able to maintain minimum reserves • Market participants and other BAs notified • Transmission limitations evaluated and revised • BA makes use of all available resources
EEA Level 3	**Firm load interruption imminent or in progress** • BA is unable to meet minimum contingency reserve requirements • System & reliability limits revaluated and revised • Immediate action taken to mitigate undue risk to the Interconnection, including load shedding.

* These are paraphrased, summarized definitions. Full definitions: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

SPP 4

A thorough explanation of the utilization of Energy Emergency Alerts can be found at https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

SWEPCO Distribution has on file a load shed plan that defines which breakers are to be opened. The shedding of this load helps to mitigate the impact of the capacity deficiency and help avoid a cascading event. See Attachment 1 for a timeline of the SPP Notices to SWEPCO, and SWEPCO Notices to Customers, during the winter weather event.

1b. From an equipment perspective, gas-fired generating units would benefit if additional precautions were taken in the natural gas industry to protect against extreme weather, to ensure continuous supply. Any significant disruption in the supply of natural gas during a period of high demand, whether such disruption is weather related or otherwise, could yield similar results to those we saw during the winter event. We have done much to improve our plant equipment, but we could provide further winterization protections based on experience with this most recent severe weather event to further fortify generating assets. Examples include the construction of new enclosures and upgrades to heat trace systems at the generating plants.

1c. Natural gas is consumed as it is delivered. With dependency on natural gas as a fuel for electric generation, it is imperative that gas supply be available during times of crisis. Further winterization of equipment by the natural gas industry would provide additional security of supply.

Defined protocols or policies to promote increased load transfer capabilities between regional transmission organizations would provide additional import capacity to support SPP or MISO customers, located in Arkansas, during extreme capacity deficiency events.

In addition to extreme weather events, cybersecurity events and insider threats have the potential to impact electric power availability for the industry as a whole. In this context, cybersecurity refers to cybersecurity of operational technology and informational technology that is used to manage the Bulk Electric System. Insider threats would include individuals with direct access to operational technology, informational technology, or physical access to Bulk Electric System infrastructure. AEP actively works to mitigate threats from cybersecurity events as well as insider threats.

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE (ERPTF)

TESTIMONY QUESTIONS

ELECTRIC UTILITIES

SOUTHWESTERN ELECTRIC POWER COMPANY

ERPTF – Question No. 2

DATE REQUESTED:	**April 9, 2021**
DATE OF RESPONSE:	**May 7, 2021**

INFORMATION REQUESTED:

With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

RESPONSE:

As a whole, the SWEPCO system, generation, transmission, distribution, and customer communications operated in conjunction with the SPP to mitigate adverse customer impacts during the winter storm, under unprecedented conditions. SWEPCO's existing generating facilities have been designed and maintained to operate in such conditions. Nonetheless, additonal review of the causes of the unplanned unit derates and outages during the winter event will identify additional steps to ensure sufficient generation to serve peak load during extreme winter events.

With regard to the Company's ability to ensure natural gas supply to its natural gas generating units, the Company could increase the amount of natural gas supplied through monthly baseload or long-term contracts (fixed price and volume), but that does not ensure delivery during a major weather event (as producers and marketers can claim force majeure if warranted by the conditions). Such changes would also likely increase fuel costs to customers.

Natural gas is consumed as it is delivered, thus a sudden disruption in supply, whether weather related or otherwise, can have a negative impact on spot prices and supply availability. If conditions prevent natural gas from being produced or made available to consumers, prices will increase and the curtailment of generating units could be required.

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE (ERPTF)
TESTIMONY QUESTIONS

ELECTRIC UTILITIES

SOUTHWESTERN ELECTRIC POWER COMPANY

ERPTF – Question No. 3

DATE REQUESTED: **April 9, 2021**

DATE OF RESPONSE: **May 7, 2021**

INFORMATION REQUESTED:

With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

RESPONSE:

The Company is committed to providing highly reliable energy to its customers. The Company is part of the SPP RTO and works with SPP and its members to ensure continued, highly reliable energy services are provided to its members. Furthermore, the Company is continuing to study various alternatives impacting the electric generation capacity and energy mix through its IRP process and in collaboration with SPP and its members. Resilincy of the grid and availability of generation resources during extreme events, including but not limited to extreme temperatures, hurricanes, tornados and ice storms, will continue to be an area of focus by SWEPCO and its stakeholders.

SWEPCO's existing generating facilities have been designed and maintained to operate in extreme conditions. The solid fuel units have adequate fuel inventory and well established sources and delivery options. The natural gas units often have multiple fuel suppliers and one is equipped with fuel oil inventory to operate when natural gas supplies are limited, and three units are equipped as "Black Start" units. The North Central Wind units are including a winterization package to support extreme winter operations. Furthermore, for capacity planning purposes, intermittent resources including wind and solar are allocated a fraction of the "nameplate" capacity for capacity planning purposes.

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE (ERPTF)
TESTIMONY QUESTIONS
ELECTRIC UTILITIES

SOUTHWESTERN ELECTRIC POWER COMPANY

ERPTF – Question No. 4
DATE REQUESTED: **April 9, 2021**
DATE OF RESPONSE: **May 7, 2021**

INFORMATION REQUESTED:

Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?

RESPONSE:

Generally, energy storage resources are available but at a higher cost than traditional energy sources and provide limited resiliency. Finding unique opportunities on the grid to deploy this technology versus more conventional approaches typically provides the greatest benefit. The unique nature of this technology does allow it to provide extremely fast response to system events. The industry and the Company continue to develop an understanding of opportunities to deploy this technology in an efficient manner.

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE (ERPTF)

TESTIMONY QUESTIONS

ELECTRIC UTILITIES

SOUTHWESTERN ELECTRIC POWER COMPANY

ERPTF – Question No. 5

DATE REQUESTED: **April 9, 2021**

DATE OF RESPONSE: **May 7, 2021**

INFORMATION REQUESTED:

What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event? Are there constraints or impediments in place that would prevent implementation of such changes?

RESPONSE:

As a result of FERC Order 841, the SPP RTO is already making changes to its systems to better facilitate the integration of storage resources in the Integrated Marketplace. However, it is important to realize that the volume of storage resources in the SPP Market today is very limited. Storage facilities will have limited additional benefit in an extreme weather event until the storage capacity is much larger, meaning peak MW of delivery, and/or the volume of energy delivered is improved.

One design element that will need additional work in the SPP systems is managing the daily energy limits of storage resources. The real time market systems simply dispatch resources based on price throughout the day without specifically reserving the energy stored in the battery for the peak period in the day. The impediment in place is simply that it takes time to design, receive approval for, and build such market systems.

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE (ERPTF)

TESTIMONY QUESTIONS

ELECTRIC UTILITIES

SOUTHWESTERN ELECTRIC POWER COMPANY

ERPTF – Question No. 6

DATE REQUESTED: **April 9, 2021**

DATE OF RESPONSE: **May 7, 2021**

INFORMATION REQUESTED:

To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

RESPONSE:

While the energy efficiency programs offered by SWEPCO do result in some demand savings by participating customers, the majority are focused on peak savings which historically occur during the summer months. SWEPCO does not currently offer demand response programs in its Energy Efficiency portfolio, outside of the Load Management program which runs during the summer. Therefore, we did not have the ability to proactively control the water heaters or heating systems through smart thermostats of residential customers, nor did we have commercial customers equipped for quick response load reduction.

In addition to the energy efficiency programs, SWEPCO has an Experimental Curtailable Service Rider which allows a customer to choose to have some portion of their demand designated as curtailable kW. These customers helped SWEPCO reduce the amount of firm load we had to curtail by approximately 17 MW. The non-firm load customers were curtailed prior to the curtailing of the firm load. Without these customers, SWEPCO would have had to curtail an additional 17 MW of firm load, such as residential customer service, during the winter weather event.

The current Arkansas Public Service Commission Rules for Conservation and Energy Efficiency Programs, targets and programs are sufficient. No changes are warranted at this time as a result of the extreme winter weather event.

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE (ERPTF)

TESTIMONY QUESTIONS

ELECTRIC UTILITIES

SOUTHWESTERN ELECTRIC POWER COMPANY

ERPTF – Question No. 7
DATE REQUESTED: April 9, 2021
DATE OF RESPONSE: May 7, 2021

INFORMATION REQUESTED:

Describe your preparedness and allocation process for critical energy resources during extreme events.

RESPONSE:

The inventory target for the SWEPCO coal generation plants (Plants) is to have 30 days of coal available at full load burn. Having inventory available on hand allows for potential plant, supply and transportation disruptions. The purchasing strategy is to purchase coal on a total SWEPCO basis in advance and make available for delivery at all times. Contracting on a total SWEPCO basis provides for the flexibility to move deliveries between the Plants. Additionally, SWEPCO transports coal under transportation agreements to the Plants with the Union Pacific Railroad which also provides the flexibility to divert unit trains between Plants on an as needed basis. This inventory and purchasing/transporting strategy allows SWEPCO to be ready in extreme, unexpected events.

From a natural gas procurement perspective, SWEPCO maintains firm natural gas transportation agreements for a portion of its fleet to ensure reliable deliveries during periods of high demand. Furthermore, SWEPCO is also a party to a long-term, fixed price natural gas supply agreement.

From a renewable energy perspective, SWEPCO is not the operator of some of its existing wind resources, which are available via purchase powr agreements, and therefore does not have as much control over their operation. With the completion of SWEPCO's pending North Central Wind Facilities, more capacity can be realized as an operator of the system. Regarding renewable resources in general, while wind and solar generation do not have stored fuel, neither are their power sources subject to interruption from competition with other needs (e.g., heating load) or other types of disruption. Their intermittent nature is largely accounted for by developing a statistically grounded capacity value.

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE (ERPTF)

TESTIMONY QUESTIONS

ELECTRIC UTILITIES

SOUTHWESTERN ELECTRIC POWER COMPANY

ERPTF – Question No. 8

DATE REQUESTED: **April 9, 2021**

DATE OF RESPONSE: **May 7, 2021**

INFORMATION REQUESTED:

Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

RESPONSE:

In the event of emergency curtailment (load shed), customers are notified through a multitude of ways including company statements to news media; social media posts; commercial, industrial and wholesale account contacts; and text/emails for customers enrolled in outage alerts. End users wishing to appeal or request consideration of unique circumstances would contact a Customer Services & Marketing representative or the Customer Solutions Center.

Southwestern Electric Power Company
Energy Resources Policy Task Force
Question 1a
Attachment 1

Notices from SPP to SWEPCO:

2/9/2021 at 0:00 AM: In response to the cold weather, SPP declares a period of conservative operations effective until further notice.

2/15/2021 at 0:00 to 5:00 AM: SPP's preemptive request that member companies issue appeals for public conservation goes into effect.

2/15/2021 at 5:00 AM: SPP declares an Energy Emergency Alert (EEA) Level 1, meaning that all available resources have been committed to meet obligations, and SPP is at risk of not meeting required operating reserves.

2/15/2021 at 7:22 AM: SPP declares an EEA Level 2 which requires SPP to ask its member companies to issue public conservation appeals, serves as a maximum emergency generation notification for resources, and informs the market that emergency ranges of any resources may be required.

2/15/2021 at 8:05 AM: SPP instructs AEP to initiate non-firm curtailment of interruptible customers.

2/15/2021 at 10:08 AM: SPP declares an EEA Level 3 when SPP is forced to begin relying on required reserve energy. This means SPP was carrying reserves below the required minimum and had initiated assistance through the Reserve Sharing Group.

2/15/2021 at 12:06 PM: SPP instructs AEP to shed 101 MW of firm load. SWEPCO is instructed to shed 58 MW.

2/15/2021 at 12:10 PM: While still under EEA Level 3 and after exhausting reserves, SPP directs member utilities to implement controlled, temporary interruptions of service.

2/15/2021 at 1:01 PM: SPP advises that all firm load shed can be restored.

2/15/2021 at 2:00PM: SPP declares a return to EEA Level 2, restoring load to the region with enough generation to meet demand and minimum reserve requirements.

2/15/2021 at 2:25 PM: SPP advises that curtailable load can be restored.

2/15/2021 at 6:51 PM: SPP instructs AEP to initiate non-firm curtailment of interruptible customers.

2/16/2021 at 12:07 AM: SPP advises curtailable load can be restored.

2/16/2021 at 3:21 AM: SPP instructs AEP to initiate non-firm curtailment of interruptible customers.

2/16/2021 at 6:15 AM: SPP declares an EEA Level 3. System-wide generating capacity had dropped below current load of approximately 42 gigawatts (GW) due to extremely low temperatures, inadequate supplies of natural gas and wind generation. SPP directs member utilities to implement controlled, temporary interruptions of service.

2/16/2021 at 6:46 AM: SPP instructs AEP to shed 227 MW of firm load. SWEPCO is instructed to shed 130 MW.

2/16/2021 at 7:18 AM: SPP instructs AEP to shed 227 MW of firm load. SWEPCO is instructed to shed 130 MW.

2/16/2021 at 9:33 AM: SPP advises that AEP can restore 227 MW of firm load. SWEPCO is able to restore 132 MW.

2/16/2021 at 10:07 AM: SPP has restored all load, meaning SPP has enough generating capacity available to meet system-wide demand. SPP remains in an EEA Level 3, indicating SPP is still operating below required minimum reserves.

2/16/2021 at 10:08 AM: SPP advises that AEP can restore remaining 227 MW of firm load.

2/16/2021 at 11:30 AM: SPP returns to EEA Level 2 until further notice, restoring load to the region with enough generation to meet demand and minimum reserve requirements.

2/16/2021 at 12:00 PM: SPP advises that curtailable load can be restored.

2/16/2021 at 12:31 PM: SPP downgrades to an EEA Level 1. While no longer an Energy Deficient Entity, all available resources are committed to meet obligations, and SPP remains at risk of not meeting required operating reserves.

2/16/2021 at 6:28 PM: SPP declares an escalation to EEA Level 2. SPP directs its member companies to issue public conservation appeals. The alert will remain in effect until further notice. At this time, SPP has enough generating capacity online to meet system-wide demand, but is taking steps to mitigate the risk of outages.

2/16/2021 at 6:33 PM: SPP instructs AEP to initiate non-firm curtailment of interruptible customers.

2/17/2021 at 12:47 PM: SPP advises that curtailable load can be restored.

2/17/2021 at 1:15 PM: SPP downgrades to an EEA Level 1. While no longer an Energy Deficient Entity, all available resources are committed to meet obligations, and SPP remains at risk of not meeting required operating reserves.

2/17/2021 at 6:20 PM: SPP declares an escalation to EEA Level 2. SPP directs its member companies to issue public conservation appeals. The alert will remain in effect until further notice.

2/17/2021 at 6:20 PM: SPP instructs AEP to initiate non-firm curtailment of interruptible customers.

2/17/2021 at 9:40 PM: SPP advises that curtailable load can be restored.

2/17/2021 at 10:59 PM: SPP downgrades to an EEA Level 1. While no longer an Energy Deficient Entity, all available resources are committed to meet obligations, and SPP remains at risk of not meeting required operating reserves.

2/18/2021 at 9:30 AM: SPP downgrades from EEA Level 1 to a conservative operations status. Due to continuing high loads and other severe cold weather implications, it will remain in a period of conservative operations until 10 PM, February 20, for the entire SPP balancing authority area.

2/18/2021 at 6:25 PM: SPP declares an EEA Level 1, meaning that all available resources have been committed to meet obligations, and SPP is at risk of not meeting required operating reserves.

2/19/2021 at 9:20 AM: SPP downgrades from EEA Level 1 to a conservative operations status. Due to continuing high loads and other severe cold weather implications, it will remain in a period of conservative operations until 10 PM, February 20, for the entire SPP balancing authority area.

2/20/2021 at 10:00 PM: SPP returns to normal operations for the entire SPP balancing authority area, signaling it has enough generation to meet demand and available reserves and foresees no extreme or abnormal threats to reliability.

<u>Notices from SWEPCO to Customers</u>:

2/14/2021 at approximately 5:45 PM: SWEPCO issues an Emergency Appeal to Conserve Energy informing the public that SWEPCO was experiencing an increased demand for electricity due to the extreme cold, and requesting that SWEPCO customers reduce their electricity use. This Emergency Appeal was issued via the news media, on SWEPCO.com, and on SWEPCO's Facebook and Twitter pages.

2/15/2021 at approximately 12:20 PM: SWEPCO issues a Curtailment Initiation Announcement informing the public that some SWEPCO customers would experience an interruption in electric service on a rolling basis for no longer than a few hours, to the extent possible. This Initiation Announcement was issued via the news media, on SWEPCO.com, and on SWEPCO's Facebook and Twitter pages.

2/16/2021 at approximately 7:00 AM: SWEPCO issues a Curtailment Initiation Announcement informing the public that some SWEPCO customers would experience an interruption in electric service on a rolling basis for no longer than a few hours, to the extent possible. This Curtailment Initiation Announcement was issued via the news media, on SWEPCO.com, and on SWEPCO's Facebook and Twitter pages.

ENERGY RESOURCES PLANNING TASK FORCE

TESTIMONY QUESTIONS
Please send your responses to ERPTaskForce@adeq.state.ar.us on or before April 30, 2021.

ELECTRIC UTILITIES - Responses of Entergy Arkansas, LLC

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

• In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event? What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?

ANSWER: The primary cause of the electric power supply / demand imbalance during the week of February 15, 2021 was the extreme weather event that affected a significant part of the United States, including Arkansas. The extreme winter weather event during the week of February 15, 2021, presented challenges at many levels for the state of Arkansas and the state's electric utilities, including Entergy Arkansas. Fortunately, our electric system in Arkansas performed well, and, service interruptions were limited in number and duration. Our employees and those of the other electric utilities worked tirelessly to ensure that customers in Arkansas had electric service. The extreme winter conditions and the associated high demand for electricity and natural gas resulted in an imbalance between supply and demand. The relationship between supply and demand was extremely tight. This was compounded by a winter weather event that affected a significant portion of the country at one time.

This weather event has caused historically high usage and demand for electricity statewide and throughout the region. By way of example, Entergy Arkansas's peak demand on February 15, 2021 was approximately 4,198 MW, which is the second highest monthly winter peak since the company joined MISO in 2013. By way of comparison, the demand on July 29, 2015, the highest summer demand since joining MISO, was 4,665MW. And of the top 15 highest hourly winter peaks since joining MISO, nine of these peaks came in February 2021. Having high usage and demand during a winter event creates additional challenges. During the summer, there is not a competing demand for natural gas for space heating. During this event, the demand for natural gas has been high both for electric generation as well as for space heating and other direct uses. Further, during the cold weather, there are challenges for the natural gas industry that their representatives can better address. Consequently, the winter high demand situation has caused real challenges for the industry (like everything else in 2020 and 2021).

Entergy Arkansas implemented the mitigation strategy of regular communication with our customers and requests for our customers to conserve electricity during the winter weather event. Throughout the week, we worked to encourage conservation by our customers to avoid service interruptions due to the high demand on the system. We used a variety of tools to convey those messages, including calls, texts, emails, broadcast and print media, and social media. Our customers responded to those requests, and that certainly helped limit the number and duration of outages during the winter weather event. Most of the outages faced by Entergy Arkansas' customers were associated with a coordinated outage called by the Midcontinent Independent System Operator (MISO) that is described in greater detail below. Our customers also experienced a limited number of other outages that were scattered across the state. Although the outages were limited in number and duration, we recognize that, to the customers who experienced an outage, those events did not seem minimal.

Another mitigation strategy and a very real benefit to Arkansas that served as a contributing factor in the state's ability to weather the storm is our diverse fuel mix for electric generation. Entergy Arkansas benefits from generating resources that include nuclear, coal, natural gas, hydro and solar. Without the significant investments to build, acquire, operate, maintain, and improve these generating facilities, the impact of the extreme winter weather would likely have been greater. During the winter weather event, we drew upon each of our state's fuel sources. The extreme cold weather presented challenges to our system. However, because of the diversity of the fuel mix, we were able to keep the lights on and power flowing with only limited interruption.

Our investment in transmission infrastructure also served to mitigate the impact of the winter weather event. Entergy Arkansas is the largest transmission owner in the state. Over the last several years, we have made significant, strategic investments in the transmission system. These investments have made our transmission network in Arkansas more reliable and resilient. Additionally, the other electric utilities have also invested in their transmission networks. These investments have strengthened the system and have helped withstand the challenges presented by the current extreme conditions and serve to ensure reliable electric service every day. Without the investments to build, operate, maintain and improve these facilities, the impact of this winter weather event would likely have been more significant.

Entergy Arkansas further mitigated the impact of the winter storm event through our significant investments in our distribution system. These investments have further strengthened the ability to respond to the challenges presented by the winter weather. Not only have we installed new facilities, we have also maintained and upgraded our existing facilities. We continue to invest in technological improvements that modernize and improve our distribution system. By way of example, Entergy Arkansas is in the process of installing advanced meters throughout our system. These meters will provide more detailed information to the Company to help improve our operations, including during extreme weather events. Customers also will have more timely information about their usage and can take steps to manage their usage and their bills, which can be affected significantly by extreme weather events. The advanced meters also help us more efficiently identify outages on our system when they occur. We are also making other improvements throughout our distribution networks to provide better information and to allow the systems to operate more reliably and efficiently. Without these investments to build, operate, maintain, and improve these facilities, the impact of the winter weather event would likely have been more significant.

Entergy Arkansas further mitigated the impact of the winter weather event through its membership in the MISO Regional Transmission Organization (RTO). As a member of MISO, Entergy Arkansas is interconnected with other utilities throughout the region. Other electric utilities in Arkansas are members of either MISO or the Southwest Power Pool (SPP) RTO. Because the extreme weather event affected the entire regions served by both MISO and SPP, the ability of the member utilities to draw upon each other's resources was limited. However, the interconnected nature of the transmission systems within and connecting the RTOs did prove beneficial. In contrast, the areas of Texas served by ERCOT are not generally interconnected with other areas and were largely unable to draw upon any resources outside of the ERCOT footprint. Further, the areas of Texas that lie in the ERCOT footprint generally have retail open access and are not served by vertically integrated electric utilities. These ERCOT utilities thus rely in large part on the competitive market to bring about investment in adequate generation resources to serve customers. That is a significant difference from the electric utility market in Arkansas where customers are served by vertically integrated, regulated public utilities, electric cooperatives, and municipal electric utilities. Here in Arkansas, the adequacy of generation resources to serve customers' needs, including during extreme events, is addressed not through competitive markets but by vertically integrated, regulated public utilities engaging in integrated resource planning under the regulatory oversight of the Arkansas Public Service Commission.

During a weather event, Entergy Arkansas can interrupt customers who are served under interruptible rate schedules, consistent with the terms of each rate schedule. The interruptible rate schedules are intended to provide needed capacity at times of scarcity, including during an extreme weather event. Entergy Arkansas can call on customers seeking to curtail those customers to free up capacity to serve its remaining customers whose rate schedules require firm service. Entergy did call upon its customers served under interruptible rate schedules to curtail their consumption during the winter weather event.

Additionally, the MISO and SPP RTOs also employed the mitigation strategies of calling for coordinated interruptions of service to maintain the reliability of the bulk electric system and to prevent damage and prolonged outages. As mentioned above, most of the outages experienced by Entergy Arkansas' customers during the winter weather occurred during the coordinated outage called by MISO. During the week of February 15, these coordinated outages were limited in number and duration and helped ensure reliable operation of the system throughout the extreme weather event. As reported in a number of sources, both MISO and SPP called upon the utilities to interrupt customers to maintain the reliability of the grid. MISO called for the interruption of customers on the southern portion of its grid, which includes Entergy Arkansas, on Tuesday evening at approximately 6:45 pm, and it instructed that all load could be restored at 9:00 pm. The Company interrupted approximately 60,000 customers in groups of approximately 20,000 in rolling, intermittent outages that lasted between 30 and 45 minutes for any individual customer with an average duration of less than 40 minutes. The news reports indicate that other utilities were also called upon to interrupt customers, and their representatives can address their experiences. MISO and SPP operate the transmission systems of numerous utilities over large regions of the country. They act, in part, to ensure the reliability of the transmission system and to help prevent widespread outages that can also damage the electric grid. The transmission system operator, in extreme circumstances and as a last resort, will call upon utilities to interrupt customer load to help protect the system.

• Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future? Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?

ANSWER: During the winter weather event, each fuel source experienced challenges that were either caused by or exacerbated by the extreme cold temperatures and the imbalance of supply and demand. Entergy Arkansas is continuing to evaluate its experience during the winter weather event to identify potential opportunities to improve the reliability and resilience of its system. The mitigation strategies employed by Entergy Arkansas during the winter weather event as described in the response above enabled the Company to respond to imbalances in electric energy supply and demand whether caused by extreme weather events. The Company continues to evaluate the experience from the winter weather events.

Imbalances in the supply of and demand for electric energy of the magnitude of those that occurred during the week of February 15, 2021 are likely going to be weather driven such as extreme heat or cold. Other factors that could contribute could be failure of or damage to a significant portion of the electric utility system. Again, those occurrences are generally related to weather related events such as storms or extreme hot or cold temperatures.

• What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?

ANSWER: The events of the week of February 15, 2021 were certainly among the most extreme conditions ever experienced by Entergy Arkansas and the other electric and natural gas utilities in the state and region. In spite of those challenges, the number and duration of the outages experienced by Entergy Arkansas' customers were limited. During the winter weather event, each fuel source experienced challenges that were either caused by or exacerbated by the extreme cold temperatures and the imbalance of supply and demand. Entergy Arkansas is continuing to evaluate its experience during the winter weather event to identify potential opportunities to improve the reliability and resilience of its system. The mitigation strategies employed by Entergy Arkansas during the winter weather event as described in the response above enabled the Company to respond to imbalances in electric energy supply and demand whether caused by extreme weather events. The Company continues to evaluate the experience from the winter weather events.

Entergy Arkansas' electric generating facilities managed through the inclement weather in February relatively well from an environmental perspective. While this was the case during February's power emergency, the likelihood for experiencing environmental compliance issues during this type of event is considerably higher. With the potential for incurring environmental issues being elevated, it remains imperative that Entergy Arkansas and the other electric utilities in Arkansas continue to maintain unit reliability during power emergencies so that load demand can be met for the safety and well-being of our customers and the communities we serve.

Entergy Arkansas prioritizes the safety and well-being of its customers even in cases where it might be in opposition to the environmental performance of a power generating facility. While it is rare that these objectives would work in opposition with one another, Entergy Arkansas urges the Arkansas Department of Environmental Quality (ADEQ) to consider implementing a policy or a procedure for requesting enforcement discretion for these types of occasions where there may be reliability issues for meeting electric demand. Should ADEQ wish to review a program which is already in place, the Texas Commission on Environmental Quality has implemented a procedure where the Reliability Entity (for Entergy Arkansas, this is MISO) is able to request enforcement discretion with respect to potentially having an environmental exceedance or violation. Entergy Arkansas works diligently to maintain environmental compliance and takes all factors into consideration, having such a policy or procedure in place would better allow for Entergy Arkansas' plant management teams to focus on unit reliability under these dire circumstances.

2. With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

ANSWER: The electric utilities under the jurisdiction of the Arkansas Public Service Commission are required to file resource plans every three years. The resource plans examine the available generating resources, the existing and anticipated electric loads of each utility, the expected growth in demand for electricity, and the resources needed in the future to meet the expected load. The electric utilities in Arkansas have demonstrated the ability to effectively plan and meet the needs for generating capacity in Arkansas. As noted above, Arkansas benefits from a diverse mix of generating resources. The utilities have indicated their intention to continue to maintain a portfolio of generating resources that includes diverse fuel resources. Maintaining a diverse mix of resources is a key mitigation strategy to being prepared to provide safe and reliable electric utility service at reasonable rates. As noted above, a diverse mix of resources enables Arkansas' electric utilities to be prepared to respond to extreme weather events and any other imbalance of supply and demand that may arise in the future.

3. With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

ANSWER: See the response to question 2.

4. Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?

ANSWER: Currently, there do not appear to be any large-scale storage technologies that are available to cost effectively provide adequate capacity to support electric loads in Arkansas for an extended period. Entergy Arkansas will continue to monitor those developments and will likely include deployment of those as part of their future resource planning.

The Arkansas Public Service Commission has authorized Entergy Arkansas to acquire the Searcy Solar facility that is currently under construction near Searcy. That facility includes a ten megawatt battery storage system. That facility should help provide experience and information operating a generating facility with storage in Arkansas. Additionally, the hydroelectric generating facility at Lake DeGray, operated by the U.S. Corps of Engineers, has a limited amount of pumped storage capacity. As noted above, there are not adequate storage technologies available to cost effectively provide adequate capacity to support electric loads in Arkansas for an extended period.

5. What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event? Are there constraints or impediments in place that would prevent implementation of such changes?

ANSWER: See the response to question 4.

6. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

ANSWER: The energy efficiency programs offered by Entergy Arkansas represent a resource available to meet the needs of the electric utility customers. Entergy Arkansas includes the energy efficiency programs in its resource plan submitted to the Arkansas Public Service Commission every three years. Reduction in consumption and demand generally contributed to the ability to weather the storm during the week of February 15, 2021. I do not have specific recommendations to the energy efficiency programs.

7. Describe your preparedness and allocation process for critical energy resources during extreme events.

ANSWER: See the responses to questions 1 and 2 above.

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

ANSWER: See the response to question 1 above. Entergy Arkansas attempts to provide customers with as much advance notice of any call for curtailment or interruption of service. Under the operating procedures of MISO, there may be times when its call for interrupting customers does not provide sufficient time for advance notice to customers. However, the MISO operating procedures do provide notification in advance that an interruption may happen on a given day, and the Company can provide advance notice to customers of the need to conserve and the possibility of interruption as it did during the winter weather event. In the curtailment or interruption of service, Entergy Arkansas attempts to identify human needs customers such as hospitals, nursing homes, and assisted living facilities.

ENERGY POLICY NETWORK

In coordination with
Mike Nasi, J.D., Jackson Walker, LP
Brent Bennett, Ph.D., Life:Powered

Response to:

ENERGY RESOURCES PLANNING TASK FORCE TESTIMONY QUESTIONS

April 28, 2021

ELECTRIC UTILITIES

Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event?

Answer

Arkansas should be aware of the Regional Transmission Organizations (MISO, SPP), whose primary role is to keep the lights on in Arkansas during severe weather.

All indications point to a regional problem concerning the shortages. Arkansas's two Regional Transmission Organizations (MISO, SPP) were both experiencing shortages during the February polar vortex. It is reported that MISO was contracting for power from as far away as PJM on the east coast.

The primary reason both MISO and SPP were experiencing power shortages is simple: while Arkansas hasn't closed a baseload power plant in over a decade, utilities in both MISO and SPP have rushed to close baseload *dispatchable* power plants.

FACT: In the past five years:

- ✓ MISO - utilities have closed **45** baseload power plants (29 coal-fueled, 15 natural gas, 1 nuclear) for a total of **17,379 MW** of electric generating capacity.
  *Equivalent to the average electricity needed to power **11.2** million homes*

- ✓ SPP – utilities have closed **15** baseload power plants (7 coal-fueled, 7 natural gas, 1 nuclear) for a total of **4,738 MW** of electric generation.
  *Equivalent to the average electricity needed to power **3.0** million homes*

In my view, the primary cause for the power shortage in February is Arkansas's contractual ties with two RTOs that have collectively closed **60 baseload power plants (over 22,000 MW) in the past five years**. These baseload power plants were replaced with ***'intermittent'*** generating sources that cannot be relied on during extreme weather events.

(Excel spreadsheet of MISO and SPP plant closures - attached)

FACT: Oklahoma's Governor Kevin Stitt echoed the need for dispatchable and resilient capacity to manage extreme weather event. Speaking to the press regarding the near collapse of the SPP grid during the recent cold spell, Governor Stitt stated that "coal was really bailing us out".

> "Renewable sources like wind and solar dropped to almost zero production. Natural gas wells froze and compressor stations went offline. That left utility companies really scrambling to buy extra energy on the spot market at skyrocketing prices. [...] Wind is normally about 40 percent and it dropped to 10 percent. Coal in Oklahoma is normally 10 percent and it went to 40 percent. I've talked to several other Governors that coal was really bailing us out in the production."

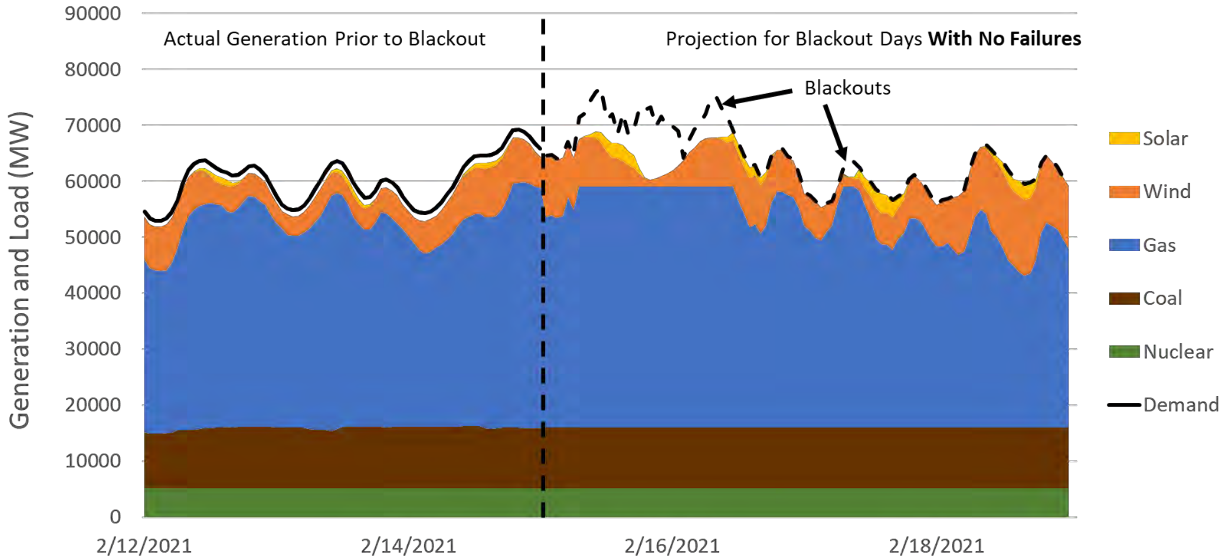
Oklahoma Governor Stitt Press Conference
February 22, 2021
Oklahoma City, Oklahoma
Reference link: https://www.youtube.com/watch?v=mCJD5AyDMOs

FACT: in the last three years, ERCOT utilities closed **6 coal-fueled** power plants **(6,233 MW)** of generation. In addition, over the past five years, ERCOT utilities shutdown **7 natural gas** plants **(3,122 MW)** of baseload generation. Combined, these baseload plants provide enough electricity to power over 6 million homes.

The effect of Winter Storm Uri on Texas is perhaps the most dramatic example of the problems caused by premature retirements of baseload coal and gas in favor of intermittent resources. Many parties have attempted to argue that more coal and gas generation would not have been necessary if the weather problems experienced by the existing generators had not occurred. That narrative is false.

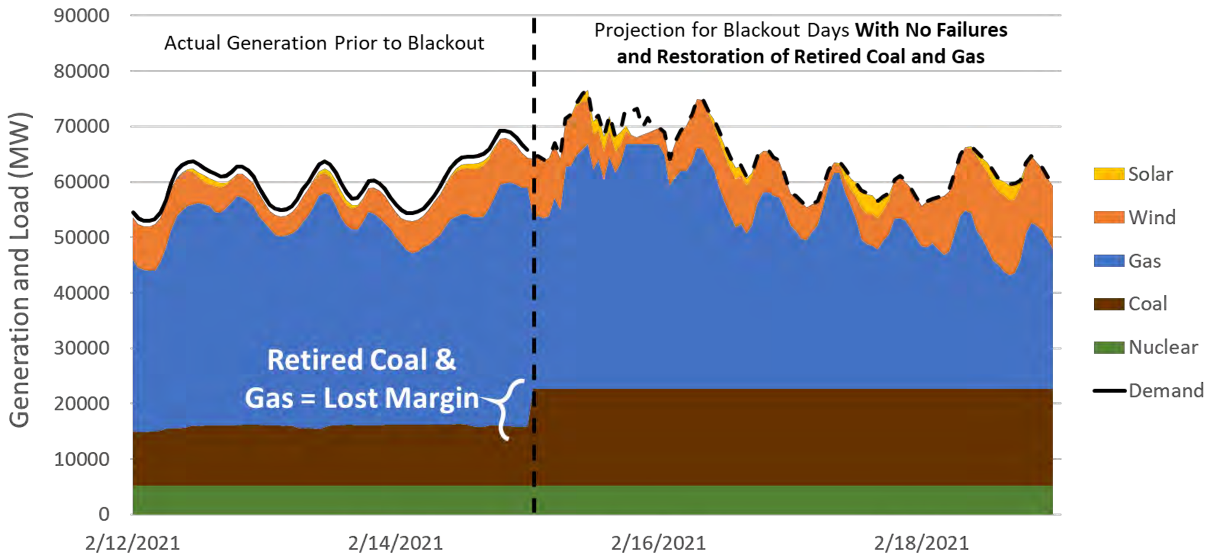
If the amount of generation outages the night of February 14th, which were normal for February, had been maintained throughout the event (no additional weather failures), the market would have likely been short for over 24 hours. Even if all the existing generation in ERCOT had been operational (all current coal, natural gas, nuclear, wind & solar generation) at 100 percent, there would have still been periods of at least a few hours where demand exceeded supply.

This can best be demonstrated by the graph below.



Source: [Energy Information Administration Hourly Grid Monitor](#)
For more information, visit [lifepowered.org](#).

> Adding back 7.5 GW of premature retirements would have reduced the outages to a few hours. Those power plants could have made an unmanageable problem far more manageable.



Source: [Energy Information Administration Hourly Grid Monitor](#)
For more information, visit [lifepowered.org](#).

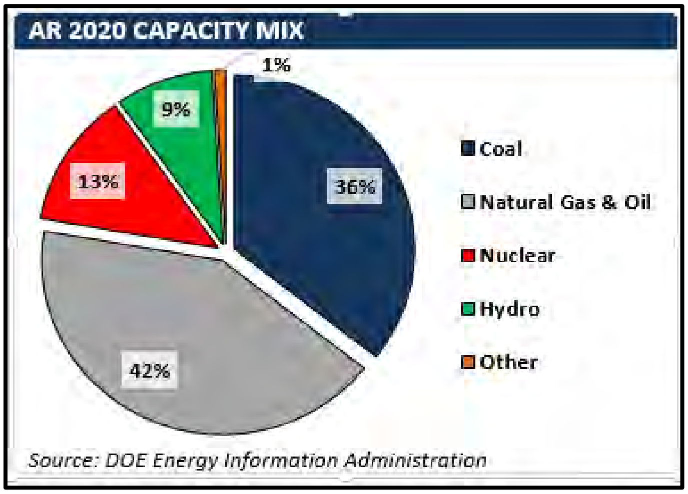
What additional strategies, regulations, protocols or polices should be developed by industry or government to ensure Arkansas has an adequate electric power supply?

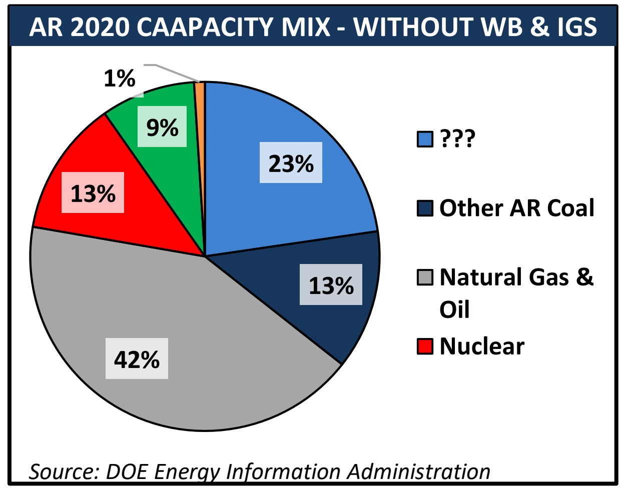
Answer

> **FACT:** Currently there are three power plants scheduled to close by 2030 (White Bluff – coal, Independence – coal, Lake Catherine – natural gas). These three power plants

represent **23 percent** of the electric generating capacity of the state. There could very well be more announcements of closures of baseload *dispatchable* plants before 2030.

(See pie charts below)





The three suggested actions listed below should ensure adequate power supply.

1) Existing baseload *dispatchable* generation should remain in operating reserve.

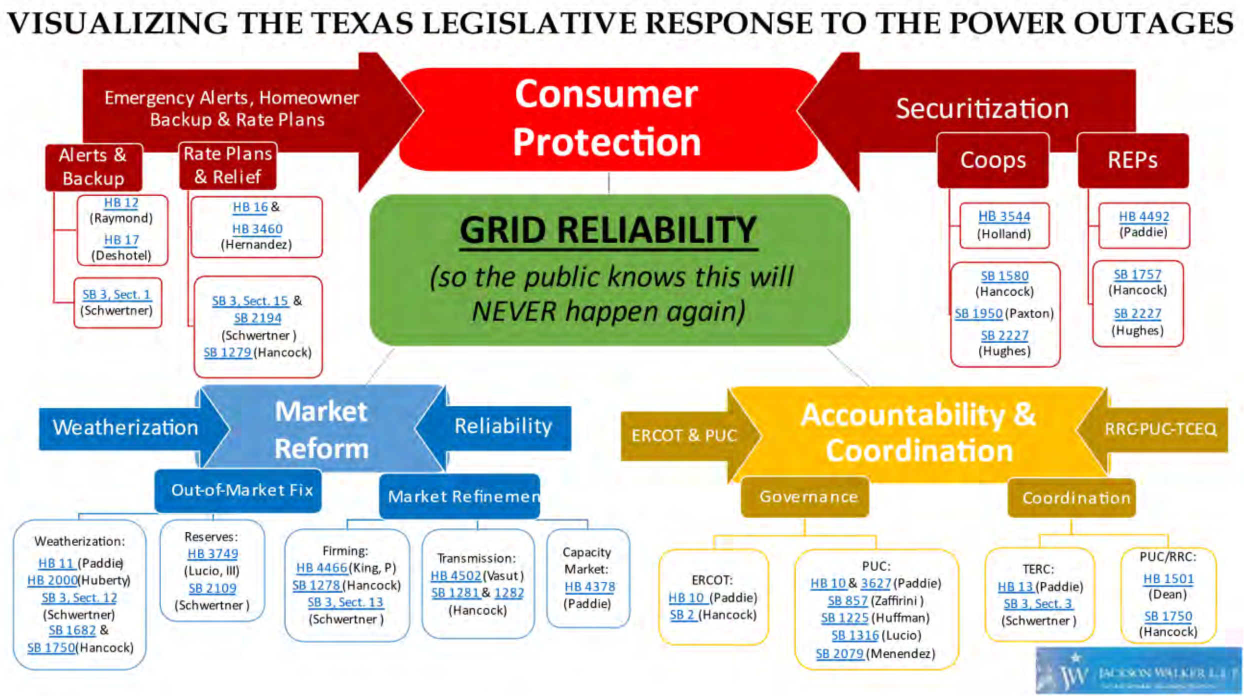
   a) It will cost to keep the baseload plants on standby, but given the cost to the Arkansas economy of the past February outages and a potential loss of life, the PSC could work with the utilities to find the most economical way to keep the plants in operation during the six months (three months during the summer, three months during the winter) of most severe weather.
   b) Even if one coal-plant were left in operation (operating reserve) it would provide enough power (1,600 MWs) for 1 million households.

2) Since Arkansas is a net exporter of power, providing a regulatory directive to the RTOs that Arkansas citizens take priority in times of extreme weather events.

   a) In situations of extreme weather, Arkansas should implement a reliability standard through the stakeholder process at SPP and MISO. Such a stakeholder process would address market rules that develop a sufficient amount of dispatchable generation to over demand during extreme weather periods.
   b) SPP and MISO are required to factor in state laws and policies in market protocols. Regulations by the APSC could place reliability checks on electricity flowing from Arkansas utilities into both MISO & SPP. Just as these RTOs are required to factor in state renewable energy portfolio standards, they would be required to incorporate these reliability standards.

3) Legislation has been introduced in six states (IN, MT, ND, TX, WY, WV) that require all new *intermittent* sources of power generation to be backed with a firm purchase power contract to become a *dispatchable* resource. Texas has introduced 43 bills addressing Securitization, Accountability, Market Reform and Emergency Alerts. The most comprehensive of these is SB 3.

The bill mandates that all intermittent power sources in the ERCOT system show verifiable firm purchase-power agreements from *dispatchable* power sources. Such firm capacity contracts are targeted for only times of the highest net load periods (demand – wind output – solar output). These are the times when demand on thermal generators is the highest and when reliability is most at risk. Arkansas should consider passing a law that requires large 'utility scale' projects to provide a firm contract for *dispatchable* power during periods of peak power.



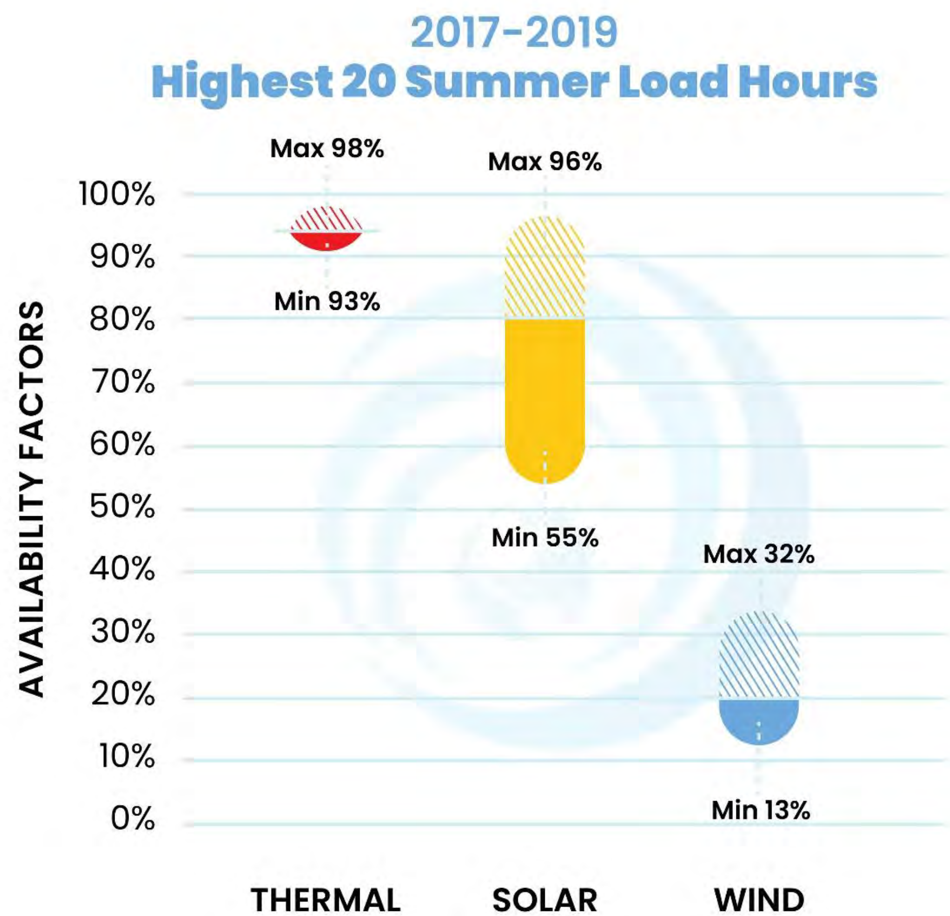
With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

Answer

Currently Arkansas has a diversified electric generation mix. With **91 percent** of Arkansas generation coming from baseload (coal, nuclear, natural gas) units. But as the chart below depicts, if the two large coal plants close (White Bluff -2028/Independence-2030) it will remove **23 percent** of the current baseload capacity.

If this 23 percent baseload is replaced with *intermittent* resources by 2030, Arkansas's electric generation mix would have **33 percent *intermittent* power**. In order to fully understand the difference between dispatchable capacity and variable renewable capacity, one need only look at their performance during peak demand periods.

Texas (ERCOT) is currently 35 percent *intermittent* power by installed capacity and therefore provides an example of the expected performance of intermittent generators on a large scale. During the highest summer load hours, the availability factor of thermal generators is always better than 90%, varying from 93% to 98%. While solar has a high resource availability during the summer, it is highly variable, ranging from less than 60% to more than 95%. Wind varies from 13% to 32%. Therefore, any market design must account for this high variability by ensuring adequate dispatchable power and ancillary services are available to make up for wind and solar shortages.



Source: ERCOT, http://www.ercot.com/gridinfo/generation

As stated in response to the previous question, there are three suggestions for "ensuring that the mix can provide sufficient generation to serve peak loads…"

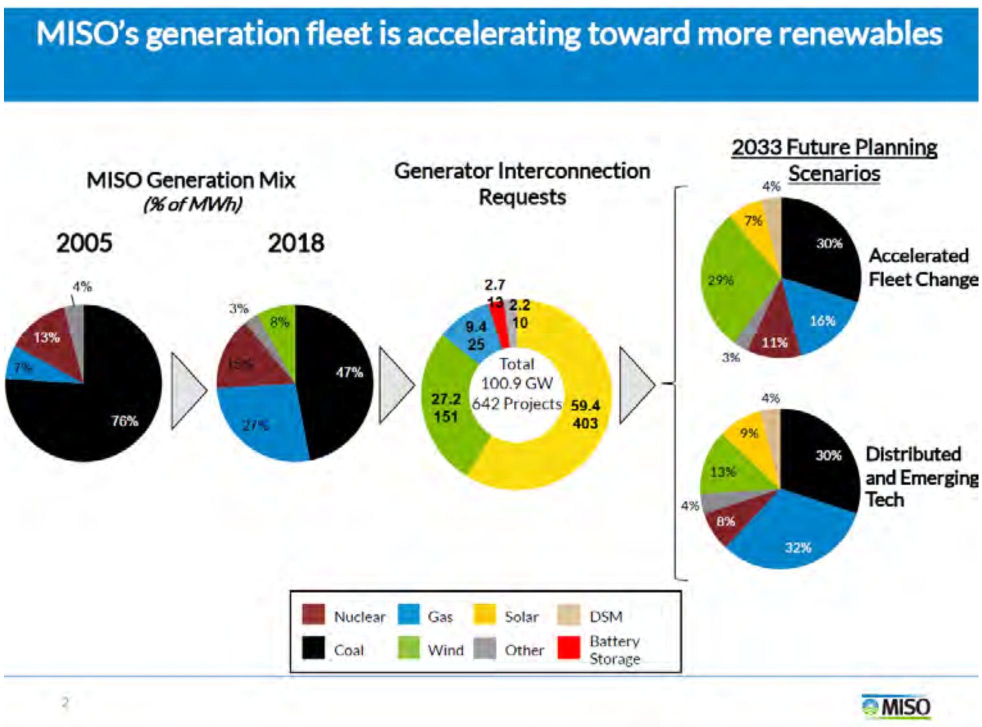
1) Existing baseload *dispatchable* generation should remain in operating reserve. There should be a financial incentive to the utilities, for continuing to operate *(at a low level)* power plants that are uneconomical.
2) Provide a regulatory directive to the RTOs that in times of extreme weather events, utilities located in Arkansas must place a priority on the safety and security of Arkansans.
3) Require all new utility-scale *intermittent* sources serving Arkansas to be backed with a firm purchase power contract for baseload *dispatchable* power.

With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

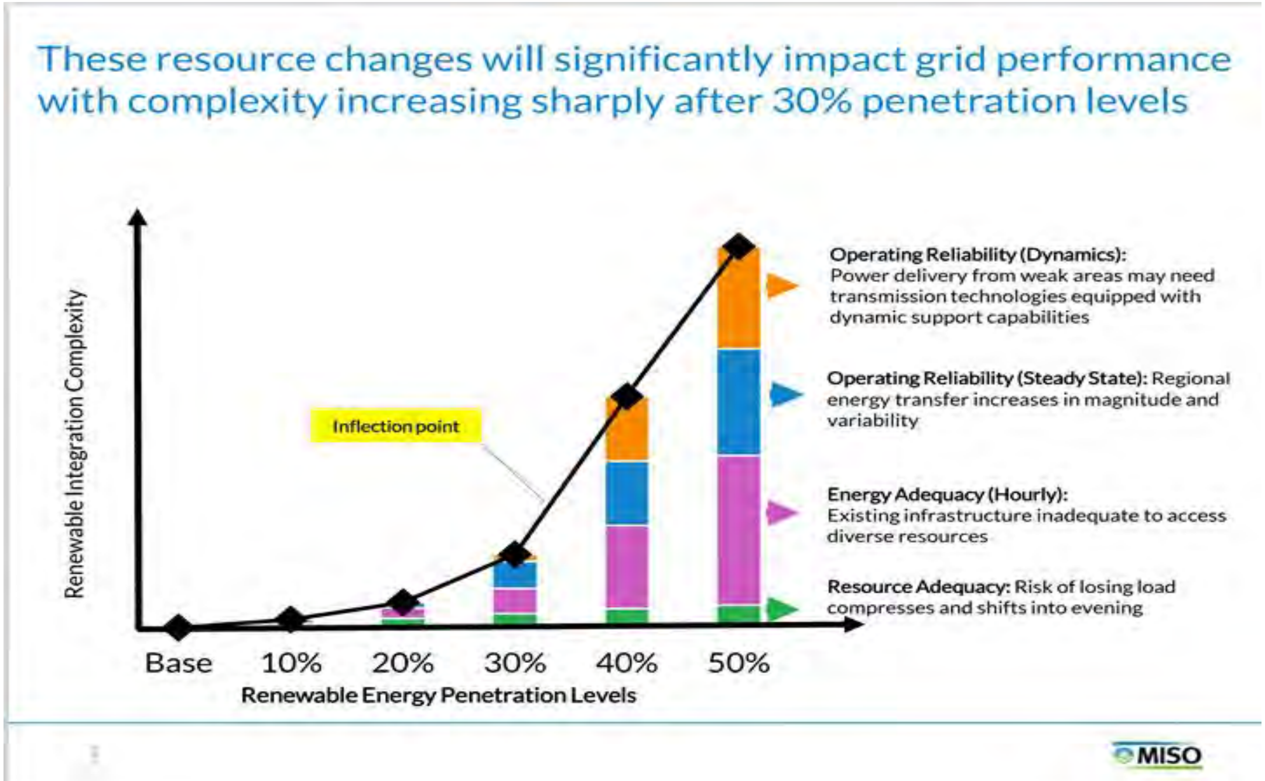
<u>**Answer**</u>

Arkansas currently has a very good electric generation mix. When you have 91 percent of your power coming from baseload plants, reliability should not be a problem. The problem for Arkansas lies in the actions of other states within MISO and SPP. As the chart below depicts, in 2018, MISO had 89 percent of its generation in baseload power plants.

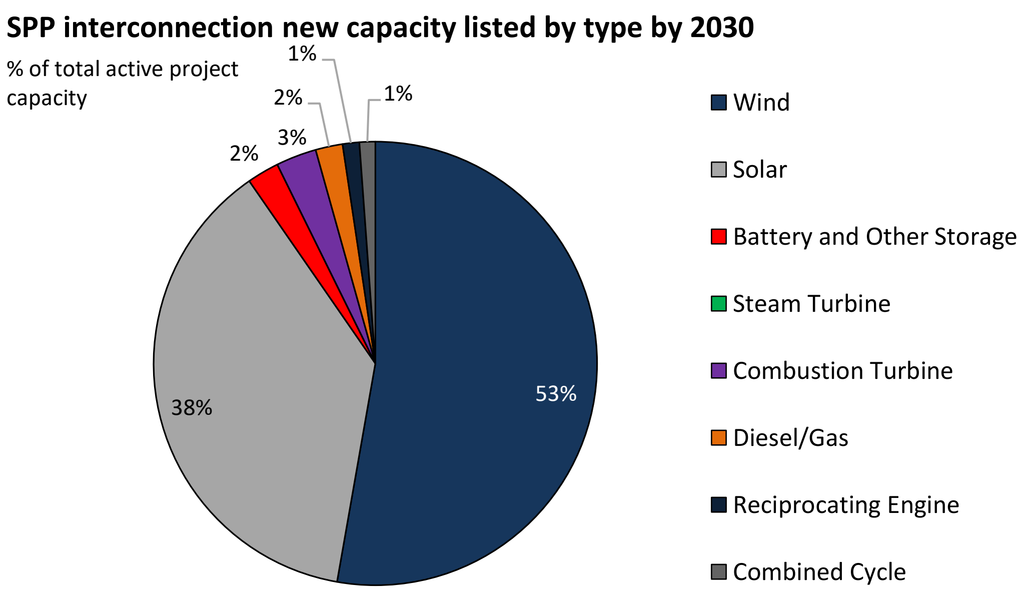
FACT: <u>Since 2018, MISO has closed **6,631 MW** of baseload power (nuclear, coal, natural gas).</u> In times of severe weather**, the closures in MISO and SPP can affect Arkansas.** Additionally, utilities within MISO and SPP plan to replace this baseload generation with ***intermittent*** power. As depicted in the graph below, some **88 percent** of new energy projects in the queue in MISO are wind and solar.



As the pie chart on the right of the chart above depicts, MISO could be 36% *intermittent* power by 2033. MISO itself admits that there will be a significant problem when the region reaches 30% *intermittent* power. Chart below. Keep in mind ERCOT is currently 35% *intermittent* generation by installed capacity and is quickly approaching 30% annual generation from those sources. It's not a coincidence that ERCOT is beginning to experience systemic problems from intermittent generation at a level that is close to where MISO was predciting problems would occur



SPP's future generation is even more telling. Some **91 percent** of new projects in SPP's interconnection queue are *intermittent* power.



Source: Energy Ventures Analysis

The reason for the rapid movement to *intermittent* power are based on two key factors.

- One is the lower cost of wind and solar. Federal and state subsidies make renewable energy marketably more attractive than baseload plants.
  (These subsidies are not expected to end. If anything they will become larger.)

- The second reason for the continued growth is the political pledges that have been made by governors, mayors and fortune 500 companies.
    a. These pledges run on the low end – carbon nutral by 2050
    b. To the high end – 100 percent renewable energy by 2040

  In order to maintain reliability, there are ways to become carbon neutral without closing needed baseload plants.

One such solution is to operate them on a seasonal bases and defining specific baseload units as '***emergency access***' units, while giving the utility a financial incentive to keep the plants with a constant fuel supply operational. Coal plants should be required to have a 30 day supply of fuel at all times.

As suggested in answers to the two prior questions, my thoughts on how best meet your question of; ***"over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load …,*** are as follows:

1) Existing baseload *dispatchable* generation should remain in **operational reserve. T**here should be a financial incentive to the utilities for continuing to operate *(at a lower level)* power plants that are uneconomical.
2) Provide an Arkansas regulatory directive to the RTOs that states, **'in times of extreme weather events, utilities located in Arkansas must place a priority on the safety and security of Arkansans'.**
3) Require all new utility-scale *intermittent* sources serving Arkansas to be **backed with a firm purchase power contract for baseload *dispatchable* power.**

Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?

Answer

There are currently many existing energy storage technologies in operation on electric grids worldwide, primarily pumped hydroelectric storage and numerous kinds of batteries. Lithium-ion batteries are dominating the list of planned projects primarily because those projects can piggyback their economies of scale with electric vehicle battery production. However, other technologies are being developed specifically for utility-scale energy storage, including liquid metal batteries and various kinds of flow batteries that use very stable liquid electrolytes. There is even research into using retired fossil fuel electric generating units for thermal energy storage.

The challenge is not finding technologies that work but reaching the required levels of cost and scale for different applications. Deploying 1-2 GW of energy storage across a system to manage frequency variations, counteract sudden losses of large generators, and assist with ramping is already being done in markets such as PJM and CAISO. These short-duration uses are well suited for energy storage. Intraday storage of solar or wind energy, shifting energy from early afternoon or late evening to the highest demand periods in the late summer afternoons, is also becoming more common as prices fall and greater scale is reached. These types of projects are being built in many markets across the Southwest U.S. to reduce the price volatility caused by changes in demand and renewable production and to help ensure resource adequacy.

The real scaling challenges come into play when energy storage is needed to replace power from dispatchable power plants in areas with high penetrations of wind and solar. A simplified way of showing how far energy storage is from this capability is to compare the cost to store the output of a 500 MW power plant over 5 hours. This comparison is generous in that most replacement scenarios require well over a day of energy storage, even with significant overbuilds of wind and solar. In a fossil fuel power plant, the coal and gas acts as a form of very inexpensive energy storage, storing enough energy to produce 2,500 MWh of electricity a cost of $30-40,000. The capital cost of a comparable Li-ion battery at current prices is about $600 million, for a per-cycle cost (assuming a 2,000-cycle life for the battery) of about $300,000. **In other words, battery costs need to fall at least 10 times to enable high renewable penetration and to even begin to offset the retirement of baseload generation.**

Furthermore, the scale of energy storage needed to achieve high renewable penetration is many times greater than anything that exists today. Using the ERCOT market in Texas as an example, achieving 50% wind and solar penetration (ERCOT is currently at about 25%) and meeting demand growth between now and 2030 requires maintaining almost all its existing thermal generation while also adding over 10 GW of energy storage. That amount of energy storage is comparable to what was operating on electric grids *worldwide* in 2019.

Moving beyond 50% wind and solar requires either maintaining a significant amount of backup capacity or a substantial expansion of energy storage. The model below maintains backup generation up to 80% penetration, so the 100% scenario indicates what would be needed if energy storage was exclusively relied on to manage wind and solar variability, approaching 1 TW (and far more than 1 TWh) of capacity, or 100 times what exists in the world today. And that is just for the Texas market.

	2018	Current Policies	50 Percent Renewables	80 Percent Renewables	100 Percent Renewables
Wind Capacity (MW)	22,066	37,596	49,877	102,928	107,737
Solar Capacity (MW)	1,861	11,019	25,372	86,091	91,597
Battery Capacity (MW)	87	527	10,626	23,260	533,833
Nuclear Capacity (MW)	4,960	4,960	4,960	4,960	-
Gas capacity (MW)	45,449	51,997	54,700	42,000	-
Coal Capacity (MW)	14,225	14,225	-	-	-

Source: Life:Powered

> In summary, the problem with using energy storage on the grid is not one of technology but of scale. Nothing in the existing energy storage development pipeline is capable of achieving the levels of cost and scale required to replace baseload generation. Given the 10 to 20-year development timeline for battery technologies, achieving high levels of renewable penetration is not something that is physically or economically conceivable for Arkansas over the next couple of decades. If Arkansas is going to utilize more intermittent generation, it *must* ensure the continued existence of adequate baseload generation and backup power to support reliability needs.

Our expertise is in generation, not in energy efficiency and demand side management, so we will not comment on the remaining questions. Our primary comment is that demand side management is helpful but not sufficient to maintain system reliability and resilience in the absence of significant dispatchable thermal generation.

Balancing Authority Code	MISO

Sum of Net Summer Capacity (MW)	Column Labels					
Row Labels	**2016**	**2017**	**2018**	**2019**	**2020**	**Grand Total**
All Other			6			6
Conventional Hydroelectric	6		5		6	17
Conventional Steam Coal	3,865	389	2,667	2,918	1,017	10,855
Landfill Gas	5	5	12	10		32
Municipal Solid Waste			1	98		99
Natural Gas Fired Combined Cycle	95	48		76	87	306
Natural Gas Fired Combustion Turbine	47	59	236	204	366	912
Natural Gas Internal Combustion Engine	3	7	13	6	13	42
Natural Gas Steam Turbine	2,607	692	1,368	207	47	4,920
Nuclear					601	601
Onshore Wind Turbine	22		1	2		25
Other Waste Biomass	2		1	3	2	8
Petroleum Coke	85					85
Petroleum Liquids	43	111	250	18	9	430
Wood/Wood Waste Biomass			61	149	38	249
Grand Total	**6,780**	**1,311**	**4,622**	**3,691**	**2,185**	**18,588**

	Balancing Authority Code	SPP

	Sum of Net Summer Capacity (MW)	Column Labels			
	Row Labels	**2016**	**2017**	**2018**	**2019**
	Conventional Hydroelectric				1
	Conventional Steam Coal	1,218	125	806	
BL	Landfill Gas	1		2	
	Natural Gas Fired Combustion Turbine	13	10		55
	Natural Gas Internal Combustion Engine	5	3	4	13
BL	Natural Gas Steam Turbine	52	73	793	16
	Nuclear	483			
	Onshore Wind Turbine		30		8
BL	Petroleum Liquids	3	5	2	7
	Grand Total	**1,775**	**247**	**1,608**	**100**

2020	Grand Total	
	1	
848	2,997	BL
	4	
8	86	
1	26	
325	1,258	BL
	483	
10	48	
1	18	
1,193	**4,921**	

PPGMR LAW, PLLC
201 E. MARKHAM STREET, SUITE 200 | LITTLE ROCK, AR 72201
P.O. BOX 3446 | LITTLE ROCK, AR 72203
TEL: (501) 603-9000 | FAX: (501) 603-0556 | PPGMRLAW.COM
LITTLE ROCK | EL DORADO | STUTTGART

JOHN PEISERICH
EMAIL: JOHN@PPGMRLAW.COM

April 28, 2021

Arkansas Department of Energy & Environment
Energy Resources Planning Task Force
Secretary Becky Keogh
5301 Northshore Drive
North Little Rock, AR 72118

via email: ERPTaskForce@adeq.state.ar.us

RE: Response to Testimony Questions
Electric Utilities

Dear Secretary Keogh:

Thank you for the opportunity to provide pre-filed testimony to the Energy Resources Planning Task Force. The February winter storms highlighted the need to evaluate Arkansas' critical energy resources and infrastructure, to evaluate the preparedness of those resources and infrastructure, and how to plan for resiliency and reliability of those resources and infrastructure for future extreme events. Generally, two components associated with grid architecture are impacted by a severe weather event – resilience and reliability. Resilience is the ability to withstand stress without operational compromise to the grid or the ability to adapt to that stress without sustained outage. Reliability is what happens once the grid is broken. Fortunately, in the February winter storms Arkansas' utilities never experienced a resilience issue and certainly never approached reliability concerns.

In the interest of providing the clearest response to the requested testimony, I have set out the questions and answers below.

ELECTRIC UTILITIES

1. Having heard the testimony some of the above entities provided to the Energy Committee, could you provide further comment on the following areas:

• In your opinion, what were the primary causes of the electric power shortage in Arkansas during the February winter event? What mitigation strategies were in place to deal with the electric power shortage experienced during the February winter event?

ANSWER: *The primary cause of the supply / demand imbalance during the week of February 15, 2021 was the extreme weather event that affected a significant part of the United States, including*

Arkansas. The extreme winter weather event during the week of February 15, 2021, presented challenges at many levels for the state of Arkansas and prompted the associated high demand for electricity and natural gas, which resulted in an imbalance between supply and demand. The relationship between supply and demand was extremely tight. This was compounded by a winter weather event that affected a significant portion of the country at the same time.

A noteworthy mitigation strategy that benefited the customers of Arkansas' electric utilities is the membership of the utilities in the Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP") regional transmission organizations ("RTO"). MISO and SPP operate the transmission systems of several utilities over large regions of the country. They act, in part, to ensure the reliability of the transmission system and to help prevent widespread outages that can also damage the electric grid. The transmission system operator, in extreme circumstances and as a last resort, can call upon utilities to interrupt customer load to help protect the system.

As RTO members, the electric utilities in Arkansas are interconnected with other utilities throughout the region. Because the extreme weather event affected the entire regions served by both MISO and SPP, the ability of the member utilities to draw upon each other's resources was limited. However, the interconnected nature of the RTOs proved beneficial. In contrast, the areas of Texas served by the Electric Reliability Council of Texas ("ERCOT") are not interconnected with other regions and were unable to draw upon any resources outside of the ERCOT footprint. Further, the areas of Texas that lie in the ERCOT footprint have retail open access and are not served by vertically integrated electric utilities. That is a significant difference from the electric utility market in Arkansas where customers are served by vertically integrated, regulated public utilities, electric cooperatives, and municipal electric utilities.

Another significant mitigation strategy that worked to address the imbalance between supply and demand is the diverse fuel mix in the portfolio of generating resources used by the electric utilities to serve their customers in Arkansas. Arkansas benefits from electric utilities with portfolios of generating resources that include nuclear, coal, natural gas, hydropower and solar. Although some solar resources generally did not contribute during this event, Arkansas' electric utilities were able to draw on other resources. Without the significant investments to build, acquire, operate, and *maintain these diverse generating facilities, the impact of the extreme winter weather would likely have been greater. During the winter weather event, the electric utilities drew upon each of the available fuel sources, and the diversity of the fuel mix allowed the utilities to keep the lights and heat on and power flowing with only limited interruption.*

Another mitigation strategy that helped to address the challenges presented by the extreme weather event is investment in the transmission infrastructure in Arkansas. Entergy Arkansas is the largest transmission owner in the state. I am aware that over the last several years, Entergy Arkansas has made significant, strategic investments in its transmission system as have the other Arkansas electric utilities that own transmission assets, and I understand that these investments have made the transmission network in Arkansas more reliable and resilient. These investments have strengthened the system and have helped withstand the challenges presented by extreme conditions and serve to ensure reliable electric service every day. Again, as noted above, without the investments to build, operate, maintain, and improve these facilities, the impact of this winter weather event would likely have been more significant perhaps resulting in not just load shedding, but system failure.

Moreover, investments in the distribution systems of the electric utilities serving Arkansas have proven to be an effective mitigation strategy as demonstrated during the extreme weather event. These investments have further strengthened the ability to respond to the challenges presented by the winter weather. It is my understanding that not only have the electric utilities installed new facilities, they have also maintained and upgraded their existing facilities. The electric utilities continue to invest in technological improvements that modernize and improve their distribution systems. By way of example, Entergy Arkansas is in the process of installing advanced meters throughout its system as has Oklahoma Gas and Electric Company as well as several of the electric cooperatives. These meters provide more detailed and timely information to the utilities to help improve their operations. Their customers also will have more timely information about their usage, which enables them to better manage their usage and bills. The advanced meters also help the utilities more efficiently identify outages on their systems should they occur. The electric utilities are also making other improvements throughout their distribution networks to provide better information and to allow the systems to operate more reliably and efficiently. To emphasize, without these investments to build, *operate, maintain and improve these facilities, the impact of the winter weather event would likely have been more significant.*

The electric utilities also employed a mitigation strategy of interrupting their customers who are served under interruptible rate schedules. The interruptible rate schedules are designed to provide needed capacity in a crisis situation such as an extreme weather event. The electric utilities can curtail those customers to free up capacity to serve the utilities' remaining customers whose rate schedules require firm service. Additionally, the MISO and SPP RTOs called for coordinated interruptions of service to maintain the reliability of the bulk electric system and to prevent damage and prolonged outages. During the week of February 15, these coordinated outages were limited in number and duration and helped ensure reliable operation of the system throughout the extreme weather event. As reported in a number of sources, both MISO and SPP called upon the utilities to interrupt customers to maintain the reliability of the grid. By way of example, Entergy Arkansas has noted that it was instructed by MISO to interrupt customers on Tuesday evening at 6:59 pm, with the last customers being restored at 8:59 pm. Entergy Arkansas interrupted approximately 60,000 customers in groups of approximately 20,000 in rolling, intermittent outages that lasted between 30 and 45 minutes for any individual customer with an average duration of less than 40 minutes. The news reports indicate that other utilities were also called upon to interrupt customers in a similar fashion. The ability of the MISO and SPP RTOs to work in a coordinated fashion, with operations centers here in Arkansas, is a significant advantage providing secure service and to minimizing the risk of system failure.

Finally, the electric utilities also employed a mitigation strategy of requesting conservation from their customers to help weather the storm. I am advised that, throughout the week, the utilities worked to encourage conservation by their customers to avoid service interruptions due to the high demand on the system. The utilities used a variety of tools to convey those messages, including calls, texts, emails, broadcast and print media, and social media. I'm sure you received emails or texts like I did in addition to hearing and seeing the news coverage. Fortunately, the electricity customers in Arkansas responded to those requests as we have seen Arkansans respond positively to emergencies so many times, which certainly helped limit the number and duration of outages during the winter *weather event. While outages were limited in number and duration as mentioned above, the utilities understand that to the customers who experienced an outage, those events did not feel minimal.*

• Given that existing strategies appeared to mitigate the severity of the electric power outages, what additional strategies could be employed to further enhance the ability to provide sufficient electric power to Arkansas in the future? Other than an extreme weather event, are there events which could impact the electric power availability and result in inadequate electric power availability?

ANSWER*: The mitigation strategies, which are expansive in scope as outlined in the response above, appear to be adequate to respond to imbalances in supply and demand whether caused by extreme weather events or other factors.*

It seems to be a reasonable proposition that imbalances in supply and demand of the magnitude of those that occurred during the week of February 15, 2021 primarily will be weather driven such as extreme heat or cold. Other factors that could contribute include failure of or damage to a significant portion of an electric utility system. Again, it may be expected that such occurrences generally will be related to weather related events such as storms. I think it is important to note that the electric utilities routinely manage through maintenance activities of generation facilities in such a way that interruptions in electric power availability do not occur. RTOs and the electric utilities work cooperatively to ensure that maintenance, even large-scale projects that take generating units offline for weeks at a time, does not result in inadequate electric power availability.

• What additional strategies, regulations, protocols and or polices should be developed by industry or government to insure Arkansas has an adequate electric power supply?

ANSWER*: As demonstrated during the week of February 15, 2021, the mitigation strategies described above worked effectively to limit the number and duration of outages during the extreme weather event. The events of that week were certainly among the most extreme winter weather conditions ever experienced in the state and region. In spite of those challenges, the number and duration of the outages were limited.*

One additional strategy that Arkansas should consider is the development of a policy or procedure for requesting enforcement discretion for events that could impact electric power resiliency and reliability. The Texas Commission on Environmental Quality ("TCEQ") has a procedure available *to the RTO to request enforcement discretion with respect to potential violation under TCEQ jurisdiction. The intent of the TCEQ policy, which Arkansas could mirror, is to suspend certain Texas Administrative Code rules because they may prevent, hinder, or delay necessary actions needed to respond to an extreme weather event. As part of its response to COVID-19, the Arkansas Energy & Environment Department, Division of Environmental Quality exercised enforcement discretion so a similar response for extreme weather impacts would not be unprecedented. Because extreme weather events impact many areas of power generation facilities and supporting activities, a variety of requirements including those related to air, water and waste management would need to be subject to enforcement discretion. A multimedia approach is necessary to determine which Arkansas-specific rules may be subject to enforcement discretion, and I would be pleased to assist in identifying those rules.*

2. With respect to the current electric generation capacity mix, what steps can be implemented to ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

ANSWER: *The electric utilities under the jurisdiction of the Arkansas Public Service Commission are required to file resource plans every three years. The resource plans examine the available generating resources, the existing and anticipated electric loads of each utility, the expected growth in demand for electricity, and the level of resources anticipated in the future to meet the expected load. This planning process enables the electric utilities to identify general resource needs and anticipated plans to meet those needs; the Commission's process also calls for competitive solicitations to be issued with respect to the identification of specific generating resources needed to meet that anticipated load. The electric utilities in Arkansas have demonstrated the ability to effectively plan and meet the needs for generating capacity in Arkansas. The utilities have indicated their intention to continue maintaining a portfolio of generating resources that is fuel diverse. Maintaining a diverse mix of resources is an important mitigation strategy in preparedness to provide safe and reliable electric utility service at reasonable rates. As noted above, Arkansas' diverse mix of resources enhances the ability of Arkansas' electric utilities to be prepared to respond to extreme weather events and any other imbalance of supply and demand that may arise.*

3. With respect to planned changes in the electric generation capacity mix over the next decade, what steps will ensure that the mix can provide sufficient generation to serve peak load during extreme weather events?

ANSWER: *See the response to question 2.*

4. Are there reasonably available storage solutions for electricity that could be implemented in the state? What are the barriers or impediments to deployment of storage technologies? Are there uses for these storage solutions during day-to-day operations in addition to providing backup during extreme peaking events, so as to reduce the cost to value ratio?

ANSWER: *Battery storage costs continue to decline. There are today certain battery storage applications, like the battery that I understand is being installed at Entergy Arkansas' Searcy Solar facility that make sense. However, currently, there do not appear to be any large-scale storage technologies that are readily available to cost effectively provide adequate capacity to support electric loads in Arkansas for an extended period. The utilities will continue to monitor those developments and will likely include deployment of those as part of their future resource planning.*

Pumped-storage hydropower is a type of hydroelectric energy storage that currently accounts for more than 90% of all utility-scale energy storage in the United States. Lake DeGray's dam is equipped with the capacity to "pump back" and, when brought on line in 1971, was the first dam with that capability in the Corps of Engineers' history. Pumped-storage could add day-to-day solutions when coupled with renewables and could provide some backup during extreme peaking events. While additional pumped-storage projects have been considered from time to time in Arkansas, the national regulatory climate for those projects seems to impose significant impediments to bringing a project to completion in a cost-effective manner.

5. What changes would you suggest integrated system operators consider to their dispatch process to allow for increasing generation for the purposes of holding electricity in storage (e.g., pump storage or battery) in advance of a forecasted extreme weather event? Are there constraints or impediments in place that would prevent implementation of such changes?

ANSWER: *See the response to question 4.*

6. To what extent did implementation of energy efficiency programs by the utilities in accordance with Public Service Commission rules reduce the need to shed load during the February weather event? Are there changes to the energy efficiency rules, targets, or Energy Office programs that should be

made to put downward pressure on electricity and natural gas heating demand through increased energy efficiency?

ANSWER: *Energy efficiency programs have been demonstrated to reduce overall demand but are generally implemented over a long period of time and, as such, probably did not directly influence the need to shed load beyond overall load reduction. While the energy efficiency programs represent a resource available to meet the needs of the electric utility customers, I do not have specific recommendations regarding those programs.*

7. Describe your preparedness and allocation process for critical energy resources during extreme events.

ANSWER: *Not applicable.*

8. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

ANSWER: *Not applicable.*

I greatly appreciate the opportunity to provide commentary on this issue. Please contact me with any questions regarding my pre-filed testimony.

Sincerely,

John F. Peiserich

ENERGY RESOURCES PLANNING TASK FORCE

TESTIMONY QUESTIONS

1. To assist the Task Force in greater understanding of lessons learned, please briefly summarize key challenges or opportunities encountered unique to the recent extreme weather events.

   There were no challenges or unique opportunities encountered as a result of the recent extreme weather events.

2. Are you aware of any planned additional Liquefied Petroleum Gas pipeline terminals in the state in the near future?

   No, we are not aware of any planned additional LPG pipeline terminals in the state in the near future.

3. Are additional pipeline terminals within the state possible?

   Yes, if the right opportunity arose additional pipeline terminals are certainly possible.

4. Are there any incentives the state could provide that would strengthen your position within the state or could help add additional terminals?

   As a pipeline operator in the State of Arkansas, we are not aware of any incentives that could help the state add additional terminals.

5. In order to pull product off your line, do you have a minimum barrel requirement? If "yes," what is the requirement?

   Yes, the pipeline has a minimum batch size of 25,000 barrels (provided however that a tender of 10,000 barrels or more will be accepted if it can be combined with Propane of the same specification to make a batch of 25,000 barrels or more) and the Pipeline may require the receiving facilities to accept delivery at full line rates.

6. Do you work off of annual purchase for seasonal allocation?

   No, as a pipeline we transport Propane for our Shippers.

7. What would recommend as the total above ground Liquefied Petroleum Gas storage requirement to adequately serve a terminal?

   A terminal should store at least ten days of anticipated terminal Propane throughput.

8. Are there any points along your pipeline in Arkansas that would readily lend itself to building a terminal?

   Our pipeline has not presently identified any points that would readily lend itself to the construction of a terminal.

9. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

   Arkansas Gas Association and Arkansas Oil Marketers Association

10. What existing regulatory requirement could be changed or done away with that would help strengthen your position within the state?

    We are not aware of any regulatory requirements that could changed or removed to strengthen our position in the state.

11. What new regulatory requirement could be put in place to ensure an adequate supply during shortages of critical energy resources?

    Regulation should focus on encouraging Propane users to maintain healthy tank inventories prior to and during the winter months and, similarly, regulations should encourage Propane wholesalers and retailers to pre-buy inventory in preparation for winter.

12. Describe your preparedness and allocation process for critical energy resources during extreme events.

    Each year prior to the winter season, the pipeline carries out routine checks to confirm critical equipment and all facilities are prepared for cold weather. This includes confirming equipment needed during cold weather is available and operational at all meter stations.

    Typically a week before a specific anticipated event, personnel convened a call to discuss the weather forecast and to go over plans to prepare for and respond to any impacts the weather might have on operations. Staffing at critical points may be increased or shifted to a 24-hour basis, and steps were taken to ensure personnel had sufficient supplies to ensure their safety if they were stranded at the facilities. Additional parts, light blankets, and other supplies are often made available.

    As a pipeline our allocation process is fair and equitable in accordance with our published allocation procedure.

13. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Routine communications between the pipeline and our Shippers, including but not limited to on the subject of allocations, are conducted utilizing our company's proprietary accounting and distribution software.

ENERGY RESOURCES PLANNING TASK FORCE

Please send your responses to ERPTaskForce@adeq.state.ar.us on or before April 30, 2021.

LIQUEFIED PETROLEUM GAS

Terminals

1. To assist the Task Force in greater understanding of lessons learned, please briefly summarize key challenges or opportunities encountered unique to the recent extreme weather events.
    - Not unique to this winter only, but most winters, marketers are required to leave the state to find additional supply that the infrastructure in Arkansas is not able to handle.
2. Are there any incentives the state could provide that would strengthen your position within the state?
    - Maybe something that might encourage marketers to invest in additional propane storage.
3. Do you currently have any expansion plans within the state?
    - We have looked at a few projects.
4. What would be your recommendations to help secure adequate supplies of Liquefied Petroleum Gas for the end user within the state?
    - Similar with what some states do with anhydrous, during a specific time period of the year the hours of service can be waived. This will allow carriers and drivers to be able to plan and prepare for the coming winter. Propane has a very strong safety record.
5. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?
    - Not at this time.
6. What existing regulatory requirement could be changed or done away with that would help strengthen your position within the state?
    - Transloading during some time periods and economic conditions could help with winter supply.
7. What new regulatory requirement could be put in place that would help strengthen your position within the state?
    - Not at this time.
8. Describe your preparedness and allocation process for critical energy resources during extreme events.
    - Private company information. I'm happy to provide, but not in this format.
9. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?
    - Private company information. I'm happy to provide, but not in this format.

Gammill Transport Company, Inc.
dba Ozark Mountain Petroleum
1939 West Main St.
Mountain View, Arkansas 72560

Phone (870) 269-8509
Fax (870) 269-5255

April 30, 2021

Testimony Question Responses

1. The biggest challenges for us during the recent extreme weather was not being able to move trucks for almost a week, which basically mad a bad situation even worse due to the face that before the event, supply was already short; therefore, leaving our customer's inventories relatively low to begin with. After the event, we were so far behind and supply was so limited that our trucks were forced to travel to neighboring states for product
2. There are no incentives that I can think of that the state could provide that would strengthen our position within the state, other than possibly adding more supply facilities strategically placed across the state.
3. A couple things that I think could help secure adequate supplies of LPS for the end user would be to strategically place rail facilities around the state and to work closely with pipeline companies and suppliers to ensure there is enough gas injected into the line to adequately supply the state.
4. I would suggest speaking to pipeline companies (Enterprise) and the main supplier within the state (NGL).
5. Lifting the hours of service sooner instead of waiting until we are in the middle of an event could really help, being as we find that we are already behind to do to supply before the event happens.
6. As stated in #5, lifting the hours of service before an extreme weather event would really help the situation.
7. I try to stay in close contact with all of our customers to help keep up with their inventories, especially when supply starts getting tight.
8. Again, trying to stay in close communication with our customers to try to stay on top of their inventory.

Thank you,

Scott Sefton

SECRETARY BECKY W. KEOGH
ARKANSAS ENERGY & ENVIROMENT
CHAIR, ENERGY RESOUCES
PLANNING TASK FORCE.
LITTLE ROCK, AR.

TO: CHAIR AND TASK FORCE MEMBERS:

WOULD LIKE TO THANK THE TASK FORCE FOR ASKING CRAFT PROPANE TO PARTICIPATE IN THE QUESTIONNAIRE. THE LARGEST CHALLENGE FOR MYSELF AND OTHER PROPANE RETAILERS IS SUPPLY AND ROAD CONDITIONS. THIS IS NOT UNIQUE TO THIS PAST FEBUAREY WEATHER EVENT, IT SEEEMS TO BE THE NORM FOR ANY PROLONGED COLD WEATHER EVENT. PROPANE SUPPLY WAS DECREASED BY A LARGE AMOUNT WHEN ENTERPRISE PIPELINE PRODUCTS REVERSED A 16" PIPELINE THAT RUNS THROUGH THE STATE IN THE SUMMER OF 2013. I WAS INFORMED BY AN ENTERPRISE EMPLOYEE THAT ENTERPRISE HAS TWO LINES A 20" & 16", THE 16" LINE WAS ONLY USED ABOUT A 1/3 OF THE TIME EXCEPT DURING THE WINTER AT WHICH TIME IT WAS KEPT FULL OF PROPANE. AS A CONSEQUENCE OF LINE REVERSAL SPACE FOR PROPANE SHIPMENTS WERE GREATLY REDUCED HAVING DEVASTATING EFFECT ON SUPPLY IN NORTHEAST ARKANSAS.

THIS QUESTIONNAIRE IS ON TARGET. INCREASING STORAGE IN THE DEALER NETWORK WOULD HAVE A VERY POSITIVE EFFECT. HOWEVER, WITH THE PRICE OF STEEL, INCREASING STORAGE MAY BE OUT OF REACH FOR SOME. INCREASING RAIL AND PIPELINE TERMINALS WOULD CERTAINLY BE THE ANSWER, THE OWNERS OF THE TERMINALS WOULD REACH OUT TO WHOLESALERS TO MARKET PROPANE THROUGH THEIR LOCATIONS. THAT BEING SAID, IT WOULD BE MY HOPE THAT THE A.E.D.C. WOULD BE ABLE TO HELP IN THE DEVELOPMENT OF TERMINAL LOCATIONS.

WHAT CAN THE STATE GOVERNMENT DO TO HELP? FOR THE PROPANE INDUSTRY THE ANSWER IS TO ISSUE AN EMERGENCY DECLARATION LIFTING THE H.O.S. REQUIREMENTS SOONER. IN PAST EVENTS, BY THE TIME EMERGENCY DECLARATIONS HAVE BEEN DECLARED, TERIMAL AND DEALER SUPPLIES ARE ALREADY VERY LOW. ROAD CONDITIONS HAVE DETERIORATED MAKING IT DIFFICUILT IF NOT IMPOSSIBLE TO CATCH UP WITH DEMAND. EXAMPLE, THIS PAST FEBRUARY THE WEATHER EVENT ARRIVED ON FEBUARY 9TH THE PROCLAMATION WAS SIGNED ON THE 23RD.

PUBLIC SERVICE ANNOUCEMENTS WOULD BE HELPFUL, INFORMING PROPANE USERS OF THE INCOMING WEATHER EVENT AND THAT ROADS COULD BE COVERED IN ICE AND SNOW IN THE COMING DAYS. URGING PROPANE USERS TO CHECK GAS LEVELS IN THEIR TANKS AND CALL THEIR PROPANE SUPPLIER FOR A FILL UP WHILE ROADS ARE CLEAR.

SINCERELY;

ROHN CRAFT

870-932-4325 • P.O. Box 15105 • JONESBORO, AR 72403

LIQUEFIED PETROLEUM GAS

Terminals

1. To assist the Task Force in greater understanding of lessons learned, please briefly summarize key challenges or opportunities encountered unique to the recent extreme weather events. The primary challenge we faced was getting additional supply into the market to meet the historic demand of the extreme weather event. The spike in demand not only affected Arkansas but the entire central United States hindering our ability to have product brought in by transports and rail from other areas as well. Our facilities that operate off of pipeline supply had a hard time getting additional product as well. Nominations for pipeline shipments have to be made by the 15th of the month prior to shipment. Forecasting what the weather will do 15 to 45 days later can be difficult. Requests to ship additional product above the original nomination is subject to the pipeline's available allocation. Customers were challenged to get to our facilities due to snow covered roads at times.
2. Are there any incentives the state could provide that would strengthen your position within the state? As discussed further in #4, tax incentives or low interest loans offered to retailers to put in additional storage would help minimize the impact of extreme weather events.
3. Do you currently have any expansion plans within the state? Our pipeline suppled terminals have adequate storage capabilities for 99% of the time. We are doing a feasibility study on adding storage at our rail terminal but terminals fed by rail are always limited by railcar inflow which again is hard to forecast for extreme weather events like we just experienced.
4. What would be your recommendations to help secure adequate supplies of Liquefied Petroleum Gas for the end user within the state? Adding additional storage at customer locations would benefit the overall supply system in the state of Arkansas. Periods of excessive demand are often unforeseen so if customers can go into those periods with higher inventory levels then it will help take some of the strain off of the supply chain when those periods do occur. At our pipeline supplied facilities, we compete against other products for line space so we are at the mercy of available line allocation to increase our shipments within a month.
5. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony? Outside the state, we work with Valero Memphis Refinery which was not mentioned in the initial phone call we received.
6. What existing regulatory requirement could be changed or done away with that would help strengthen your position within the state? Allow temporary GVW of propane transports to be increased to maximize the product moving to the needed places more efficiently. Along the same lines, allow larger transport tankers (currently used in some other states) to temporarily haul in state during these times of high demand.
7. What new regulatory requirement could be put in place that would help strengthen your position within the state? The state should continue to allow temporary exemptions on driver log times during periods of excessive demand.
8. Describe your preparedness and allocation process for critical energy resources during extreme events. Our marketing and supply team in Tulsa does everything they can to be prepared for the demands of an upcoming season. Unfortunately, we do not have the ability to see such extremes as witnessed this winter to be prepared for this. Our allocation process works by supplying each customer an allotment of product based on what we have in supply and what they have pulled from the terminal in the past. In other words, the more business

they do with us, the more loads they are allocated during times of high demand and low supply. The ratio of loads allocated is directly related to the amount of business they have done with us in the recent past.

9. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification? Our sales people notify customers by email and phone calls, and vice versa.

LIQUEFIED PETROLEUM GAS

Dealer

1. To assist the Task Force in greater understanding of lessons learned, please briefly summarize key challenges or opportunities encountered unique to the recent extreme weather events.

Dealer 2- This winter was kind of a "Perfect Storm" where we saw bitterly cold temps and then a terminal shut down. Can't really plan for both those to happen. We had our loads scheduled appropriately but then road conditions got tough.

Dealer 3- First major obstacle: the suppliers (Transports) stopped delivering to us. While there was a day to two days where the roads where inaccessible, the gas we ordered a week before the storm was never delivered. Our storage tanks were full as the calls came in and we were supposed to receive transports to keep them full before the storm, but they stopped delivering to us 4 days before the snow came and didn't deliver for another 3 days after the worst of the storm hit. Second major obstacle: road conditions. We ran trucks every day and some counties did a great job on the roads while others waited days before they would clear the major roads. It would take two hours to make a delivery that was normally done in 15 minutes. Third major obstacle: the wholesalers that had monthly price contracts used their legal exit clauses to break the contracts and increase prices substantially. While I understand the prices are based on a set benchmark plus X…the increasing of X because of cold weather doesn't make sense to me. The benchmark (adjusted daily) increased because of demand why would X increase. If we raised our prices like that then the end user would be filing price gouging complaints.

2. Are there any incentives the state could provide that would strengthen your position in the state?

Dealer 3- Reduce taxes/fees and use that as an incentive for companies to invest in their own storage and equipment.

3. Would increasing storage in the dealer network help manage an adverse weather event?

Dealer 2- We are definitely looking at increasing our storage capacity partly due to growth but also to prevent what happened this winter

Dealer 3- I believe an increase in storage will help but at what costs? It is hard to ask the retailers to spend X amount of money to increase storage and pay annual maintenance costs if these storms are not frequent enough to support the costs. Our objective is to sell propane and having more of it will always help, assuming the storage doesn't cost us more than we can sell it for.

4. Would an increase in the number of wholesalers in the state help manage an adverse weather event?

Dealer 1- not really, the number of wholesalers would still be the same gallons. Transloading facilities would help though

Dealer 3- An increase in competition cannot hurt…the small propane dealers get moved down the priority list with the wholesalers because we don't have enough business to entice them to help us.

5. Would an increase in the number of pipeline or rail terminals within the state help manage an adverse weather event?

Dealer 1- No because there are only so many hours in a day to access product

Dealer 3- I believe it would help. The majority of wholesalers in our area are bringing propane from out of state. Make it where the bobtails can go get the propane in state if the transports don't want to deliver.

6. Are there other entities not included in the Executive Order from which the Energy Resources Planning Task Force should hear testimony?

7. What existing regulatory requirement could be changed or done away with that would help strengthen your position within the state?

Dealer 1- Davy Jones Piracy Act; must have a US flagged vessel to deliver gas

Dealer 2- Governor and our LP Gas Board did a great job loosening up hours of service and giving us the authority to fill other companies' tanks to get people through the horrible weather. We also had some fellow dealers that shared some gas with others. That was a huge help. Thanks Danmar Propane!!!!!!!!!!

8. What new regulatory requirement could be put in place that would help strengthen your position within the state?

Dealer 1- Can't think of any

9. Describe your preparedness and allocation process for critical energy resources during extreme events.

Dealer 1- Dealers should not let tanks run low in the winter

Dealer 2- We had locales scheduled daily to keep up with demand but you just can't plan for the road conditions, cold weather and then a terminal going down

10. Describe your notification process to end users when curtailing services. How does the end user appeal or request consideration of unique circumstances upon notification?

Dealer 2- We notified our customers via Facebook and our website to conserve fuel.

Dealer 3- We spoke with them as the calls came in and put out notices via our social network products. The end user would just need to provide our office any notice whether in writing or via calls if they have a unique circumstance that needs to be addressed.

Dealer 4 overall answer- Probably for most the immediate answer is to increase storage capacity where needed and to keep in the top side of your inventory instead of the low side of your storage capacities.