Appendix

Winter Weather

Preparation Report

Appendix 1

City of San Antonio

Community Emergency Preparedness Committee Report

A Response to the February 2021 Winter Storm

Dated:

June 24, 2021

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I. INTRODUCTION

In early February 2021, millions of people in Texas were affected by extreme winter weather that came with the arrival of Winter Storm Uri[1]. Several days of unusually low temperatures, ranging within single digits across the state[2], combined with snowfall and ice, resulted in, among other things, calls from the Electric Reliability Council of Texas (ERCOT) to shed electric power by initiating rolling power outages on Monday, February 15, 2021[3]. This severe weather left millions of people across the state, and hundreds of thousands of people in San Antonio, without power for several days in freezing temperatures.

The residents of the City of San Antonio (City) experienced one of the worst weather-related crises to ever hit the San Antonio community when several inches of snow and extreme cold led to widespread, prolonged power and water outages, closures of roads and businesses, and burst pipes throughout the City of San Antonio. For the first time, residents across the City, and in the City's utilities service area, found themselves without power, heat, or a safe place to go. These unprecedented weather conditions, accompanied by an already stressed city confronting a global pandemic, resulted in a citywide disaster[4]. Winter Storm Uri (Uri) is accredited with causing a cascade of events including citywide power and water outages, limited availability of essential healthcare, technology, dangerous roadway conditions, burst pipes and failure of other essential infrastructure.

Before, during, and in the immediate aftermath of the storm, City, County, community leaders, and concerned neighbors from across San Antonio organized emergency relief efforts to protect the most vulnerable residents in the community. They organized food and water distributions, delivered hot meals and blankets to senior living communities, and provided direct cash assistance to families through mutual aid funds. In many cases, community-based groups were the first to identify and respond to emergency situations involving our elderly, homebound, homeless, and digitally disconnected residents. However, the winter storm, which lasted for ten (10) days, compounded the conditions that San Antonio' most vulnerable residents were already living in, including a global pandemic, high unemployment, a housing crisis, and the daily challenges that accompany poverty. The residents, who stepped up to help their neighbors, demonstrated courage, selflessness, and a deep commitment to San Antonio's collective well-being.

In addition to the winter storm's immediate impact, the City and municipally owned utilities were unable to adequately respond, provide timely information, and quickly mobilize resources in a time of need. Consequently, the community has brought calls for transparency and accountability from those entrusted

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[1] National Oceanic and Atmospheric Administration and National Weather Service Austin/San Antonio Weather Forecast Office Weather Event Summary, "February 2021 Historical Winter Storm Event South-Central Texas", 10-18 February 2021, https://www.weather.gov/media/ewx/wxevents/ewx-20210218.pdf

[2] See Figure 1 Feb. 2021 Daily Temp vs. Historidal 11-YR Ave Temp in San Antonio, TX.

[3] "Timeline: How the Historic Winter Storm, Texas Blackout Cold-Stunned the San Antonio Area." KSAT. KSAT San Antonio, March 1, 2021. https://www.ksat.com/news/local/2021/02/25/timeline-how-the-historic-winter-storm-texas-blackout-cold-stunned-the-san-antonio-area/.

[4] Nirenberg, Ron, and Nelson Wolff. "Joint Declaration of Disaster." City of San Antonio and Bexar County, February 13, 2021. https://www.sanantonio.gov/DesktopModules/EasyDNNNews/DocumentDownload.ashx?portalid=0&moduleid=24373&articleid=20111&documentid=678

with protecting San Antonio residents. While frustrations continued to grow in the community and news spread of a near catastrophic failure of Texas' energy grid managed by ERCOT, it became clear that communities across the entire state need to take steps to better ensure that their utilities are more resilient in cold weather.

At the request of Mayor Ron Nirenberg, a Community Emergency Preparedness Committee was established to better understand what happened during the winter storm with respect to the emergency communications and service delivery efforts of the City of San Antonio's Emergency Operations Center (EOC), the San Antonio Water System (SAWS), and CPS Energy. The severe and extended cold led to a power shortage across the State of Texas causing power utilities to conserve or reduce power to meet the needs of the residents of the State. San Antonio's power provider, CPS Energy, in its efforts to meet the City's demands, was challenged with load-shed orders, equipment failures, and managing rolling outages. The outages led to challenges for the City's water utility, San Antonio Water System. Pumping stations shut down due to a lack of power. SAWS was unable to provide water to most locations. When water was able to flow, delivery of water was complicated by frozen and damaged supply lines. The Emergency Operations Center, the base for City operations during an emergency, is charged with coordination of City efforts related to (1) ascertaining accurate information on the emergency situation, (2) determining and prioritizing emergency services and coordinating them, (3) providing resource support, (4) organizing and activating mass care operations and (5) warning and informing the public. There were challenges within the EOC. A lack of situational awareness made gathering of information and sharing information with the public more difficult and less effective.

In order to reduce or eliminate the compounding of complications in the future, Mayor Ron Nirenberg appointed seven members to the Committee on Emergency Preparedness (CEP or Committee) to execute this charge. The primary purpose of this investigation is to understand (1) what caused the problems that resulted in interruptions to utility services, leading to severe community impacts under dangerous winter weather conditions, (2) why were the communications to the community during the winter weather event so ineffective and inefficient, and (3) what City and Utility leadership can do to better prepare and respond to future significant emergency events with changing conditions and cascading impacts.   The Committee was tasked to produce a report of the results of its investigation to the Mayor upon completion.

II. METHODOLOGY

The CEP, in fulfilling its charge to delve into the issues and provide recommendations on a pathway forward, embraced two tenets: transparency and inclusiveness. Transparency is a vital component of good government and strong communities. All Committee meetings were live-streamed which provided the opportunity to view CEP proceedings in real time. The Committee placed all the information it gathered on-line, striving to ensure the information was posted in an understandable and easy to use format, to the Emergency Preparedness Committee website, https://www.sanantonio.gov/emergency-preparedness/. This information on the website is provided in both English and Spanish so that it is accessible to the largest number of community members.

Inclusiveness is another component of good government and strong communities. With this in mind, the Committee developed various community input options which were made available on its website and through other mediums. As part of its work, the CEP invited the public to (1) submit comments, questions, and concerns through a survey, 311, an email contact form[5], and their respective City Council offices, (2) observe the open Committee meetings, and (3) review content generated from the work of the Committee. More than 250 comments and questions were received from the community, and a summary of this feedback is available in a separate document on the Committee's website.

The Approach

The Committee's approach involved four mechanisms: the subdivision of areas of focus, a question and response approach to gathering information, the analysis of information, and the formulation of recommendations. Given the three areas of investigation, the Committee determined that the most comprehensive way to complete its work was to divide the task into three separate, but related, parts: the preparedness and response of CPS Energy, San Antonio Water System (SAWS), and the San Antonio Emergency Operations Center (EOC). The CPS Energy subcommittee consisted of Reed Williams and Ana Sandoval, the SAWS subcommittee consisted of Manny Pelaez and Clayton Perry, and the EOC subcommittee consisted of Gen. Edward Rice, USAF (Ret.), Lisa Tatum, and Dr. Adriana Rocha Garcia. Although each subcommittee began their work independently, all questions and responses were ultimately reviewed and analyzed by all Committee members and all analysis and recommendations were a product of the entire Committee's deliberations.

The Committee determined early on that the most effective and efficient way to gather and assess the required information was to develop a detailed set of questions for each entity (CPS, SAWS, and the EOC). These questions included input from the public through the various avenues made available during this investigation. Over one hundred (100) Requests for Information (RFI's) were submitted to the three entities and the Committee was satisfied that the responses enabled them to adequately understand and evaluate what happened before, during, and after the winter storm event. The information gathered afforded the CEP the ability to develop a timeline and more comprehensively understand the sequence of events[6]. All RFI's and responses are found on the Committee's website www.sanantonio.gov/emergency-preparedness.

The CEP was not only charged with gathering information about the preparedness and response to Winter Storm Uri, but with analyzing what went wrong and why. This analysis was derived from a combination of "lessons learned" from the three entities, an outside expert review conducted by Black and Veatch, and individual committee member experience and expertise. After a thorough review of what went wrong during Winter Storm Uri and why, the Committee developed a set of recommendations. The Committee's analysis recommendations are found in Section III of this report.

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[5] https://www.sanantonio.gov/emergency-preparedness/Contact-Us

[6] The Timeline (Exhibit A)

III. Analysis and Recommendations

In order to more clearly understand what happened and why, the Committee looked at three seemingly distinct but, in this case, interrelated entities and the sequence of events these entities faced and navigated through during the course of the winter storm. What follows are three discussions, based upon the CEP's analysis, of the circumstances and responses of three entities: CPS Energy, SAWS and the City of San Antonio Emergency Operations Center. It is the expectation of this Committee that as each discussion transitions to the other, the overlap of the timeline becomes more evident, revealing more precisely the cascading of events and the resulting challenges these entities faced over time. The fourth discussion is focused on the San Antonio community and how the weather affected residents, touching upon the most frequently mentioned impacts. The circumstances and cascading of events have led the Committee to draw certain conclusions and to propose recommendations.

A. CPS Energy

The Failure of Deregulation

Deregulation of electric power in Texas by the Legislature has degraded the resiliency and reduced the reliability of the Electric Regulatory Council of Texas (ERCOT) grid over the last twenty years; subjecting CPS Energy customers to a greater risk of extended power outages during a crisis.

Historically all electric power producers in Texas served customers in a certificated area and were economically regulated by a government entity. Since 2001, the Texas Legislature allowed areas of Texas not to be economically regulated. In these areas, customers are allowed to select an electric power provider competing with other providers in the same service area. The Texas Legislature spawned an unregulated industry of electric power producers and marketers to increase competition expecting increased competition would reduce the cost of power to Texans.

The new legislation did increase competition. Large industrial and commercial purchasers who can manage their own demand and supplement their demand with backup generation have been able to reduce power costs. However, the legislation only requires the customer to pay for the electric power supplied, which is referred to as an "energy only" market. The customer does not pay the power marketer or electric generator to install and maintain reserve generation capacity. Reserve generation capacity increases resilience during disruptive and destructive events such as the recent winter storm.

Before deregulation, all utilities included the costs of installing and maintaining reserve capacity in their cost of service and recovered those costs in the rates approved by the economic regulator for the utility. Since deregulation, all providers, including "energy only" providers, are no longer required to hold reserve generation capacity. Municipal utilities and rural electric cooperatives now competing with "energy only" marketers have had a history of investing in reserve capacity to maintain reliability for their customers. Today, these regulated utilities are either competing directly with "energy only" marketers or supporting the ERCOT grid, facilitating the business of the "energy only" marketers.

The utilities competing with the "energy only" marketers are at an economic disadvantage if they invest in reserve generation capacity. The rate payers to municipal utilities and rural electric cooperatives have been paying to maintain existing reserve generation capacity. Unfortunately, the reserve generation capacity is aging, and many plants built during the period of regulation are past their replacement dates. For the last twenty years ERCOT has relied on these aging investments to provide reliability and resilience to the grid.

Under the current regulatory scheme, the Public Utility Commission of Texas cannot compel any generator to invest in and maintain a prescribed amount of reserved capacity. Customers of CPS Energy have been paying to maintain aging generation plants. However, it is doubtful that CPS Energy customers will be willing to pay for new generation capacity when ERCOT can command CPS Energy to withdraw power from their customers and support "energy only" marketers on the grid. CPS Energy customers subsidizing "energy only" marketers is simply not equitable.

On May 6, 2021, ERCOT issued their report on the Capacity, Demand and Reserves (CDR) for the ERCOT grid from 2022 through 2026. In the CDR, the firm peak load demand is projected to be only 61,821 MW for the 2021/2022 winter season. For the same period, the operational generation capacity is 81,452 MW and with planned expansions the capacity is projected to be 87,813 MW. A reserve capacity of 42% appears reassuring. However, the current generation capacity includes 6,932 MW of renewables and the planned expansions that might not occur with 67% of the expansion being renewables.

ERCOT also issued a Seasonal Assessment of Resource Adequacy (SARA) for the Fall of 2021 on May 6, 2021. The SARA report estimates the total resources to be 91,301 MW compared to an adjusted peak demand of only 62,662 MW, which is an even better reserve margin. Since the recent winter storm, ERCOT started including risk scenarios in the SARA. The risk scenario most similar to the recent winter storm indicates a shortage of generation capacity of 13,359 MW. This projection is better than the 20,000 MW peak load shed during the storm, but is highly dependent on approximately 11,000 MW of existing and planned renewables operating as expected.

If we encounter another winter storm similar to that experienced in February of 2021, then Texans will experience similar local impacts from forced outages as a result of load shed demands by ERCOT. In the February 24, 2021 ERCOT Board of Directors meeting, staff estimated the peak load without load shed would have been 76,819 MW. The estimated maximum load requirement during the winter storm without using load shedding actually exceeds the previous record load requirement, which was 74,820 MW on August 12, 2019. To avoid a repeat of this disastrous event, new base-load plants, dispatchable generation, and new storage capacity technologies must be installed. ERCOT plans to double reserve margin in the next few years as illustrated in the CDR. A large majority of the increased capacity is planned to be in renewables. Electricity generated by wind and solar can drive down real time ERCOT prices and is good for all consumers when operating. Unfortunately, the low prices for renewables disincentivizes investments in new reserve capacity required to respond to a crisis, such as base load power plants, dispatchable generation units, and new storge technologies.

CPS Recommendation 1: CPS Energy and the City of San Antonio join with other cities, municipal utilities, and rural electric cooperatives to develop and propose legislation in the 2023 legislative session to accomplish the following:

1.A require all generators and marketers on the ERCOT grid to maintain a prescribed level of reserve capacity from base load plants, dispatchable plants or energy storage facilities

with direct ownership of generation capacity or firm contractual agreements with generators,

1.B **require the State of Texas to make the investment to connect the ERCOT grid to the larger grids east and west of Texas, and**

1.C **require the State of Texas to guarantee loans for all generators, transporters or marketers on the ERCOT grid to build or contract for required capacity which can supply firm dispatchable supplies from generation plants or energy storage facilities to the ERCOT grid during a natural disaster or extreme weather conditions.**

Interference in the Free Market

The Public Utility Commission of Texas (PUCT) manipulated the electric power price on the ERCOT grid artificially inflating the cost of electric power, signaling the natural gas markets to excessively increase the cost of natural gas and irresponsibly costing the residents of Texas billions of dollars.

Approaching Valentine's Day of 2021, Texas faced a historic winter storm. The daily high temperatures were compressing on the daily low temperatures, which were near freezing. From the February 14 until the end of the storm the low temperatures remained below freezing and the high temperatures did not rise above freezing until February 17 as illustrated in the following graph, Figure 1, which plots the daily average high and low temperatures compared to the average daily high and low temperatures for the previous eleven years in San Antonio, Texas, as recorded by Weather Underground[7].

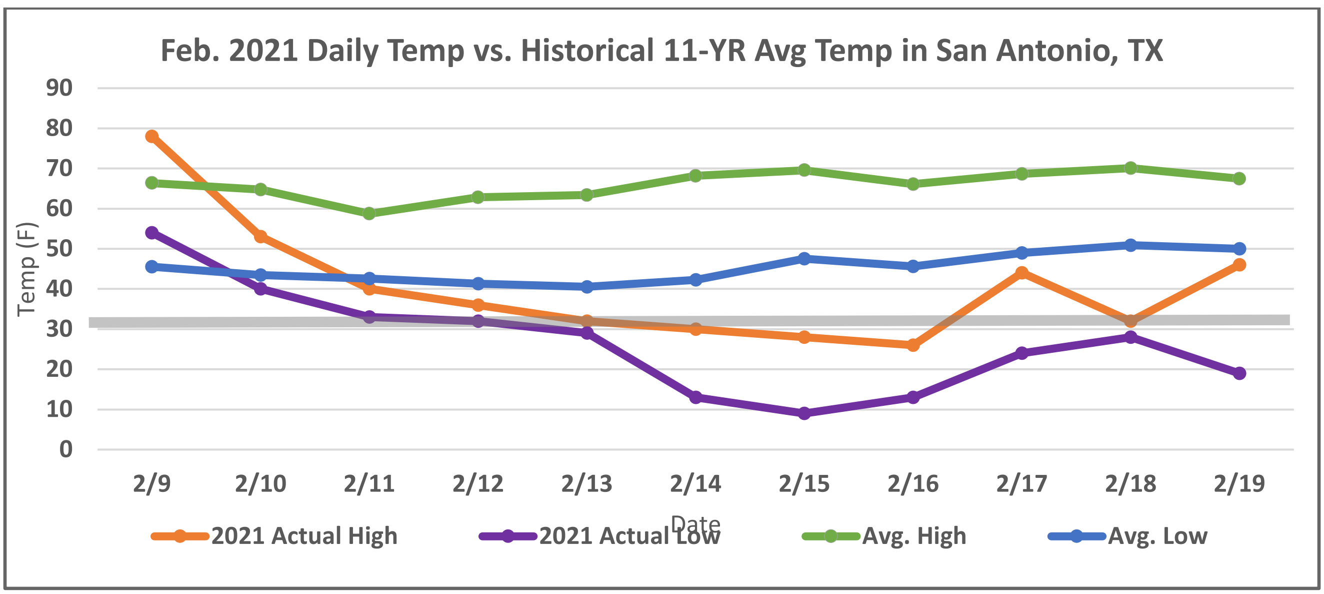

Figure 1

ERCOT, who operates the electric grid in most of Texas declared Emergency Operation Level 3 (EEA 3) at 1:20 AM on February 15th. In the next 50 minutes, ERCOT ordered grid participants to reduce distribution to their customers by 10,500 MW which is termed load shedding. The load-shedding was

[7] "San Antonio, TX Weather History | Weather Underground". 2021. *Wunderground.Com*. https://www.wunderground.com/history/monthly/us/tx/san-antonio/KSAT/date/2021-2.

required because in the early hours of February 15th approximately 20,000 MW of electric power generation capacity failed.

To put the severity of the problem in perspective, the total installed capacity on the ERCOT grid is 107,514 MW. Prior to the February 15, slightly under 30,000 MW of capacity was already out of service, which included 14,000 MW of renewables and 2,800 MW of scheduled outages for maintenance. In the early morning of February 15, approximately 20,000 MW of generation capacity failed. Around 1:53 AM, ERCOT came within seconds of a system wide failure when the grid frequency dropped below 59.4 Hz. The ordered load-shed of 10,500 MW was sufficient to stabilize the grid. The maximum amount of generation loss reached 52,277 MW, which is 48.6% of the installed generation capacity on the ERCOT grid. The loss of generation capacity remained in the 50,000 MW range until the morning of February 17th, when the temperatures started to moderate.

During the day of February 15, ERCOT was faced with massive failures at the generation plants and frustration with the market price for ERCOT power, as determined by the bid and ask prices reflected in the 15-minute real time free market. The actual real time price paid or received by CPS Energy for power in 15-minute increments is plotted in the following chart (Figure 2).

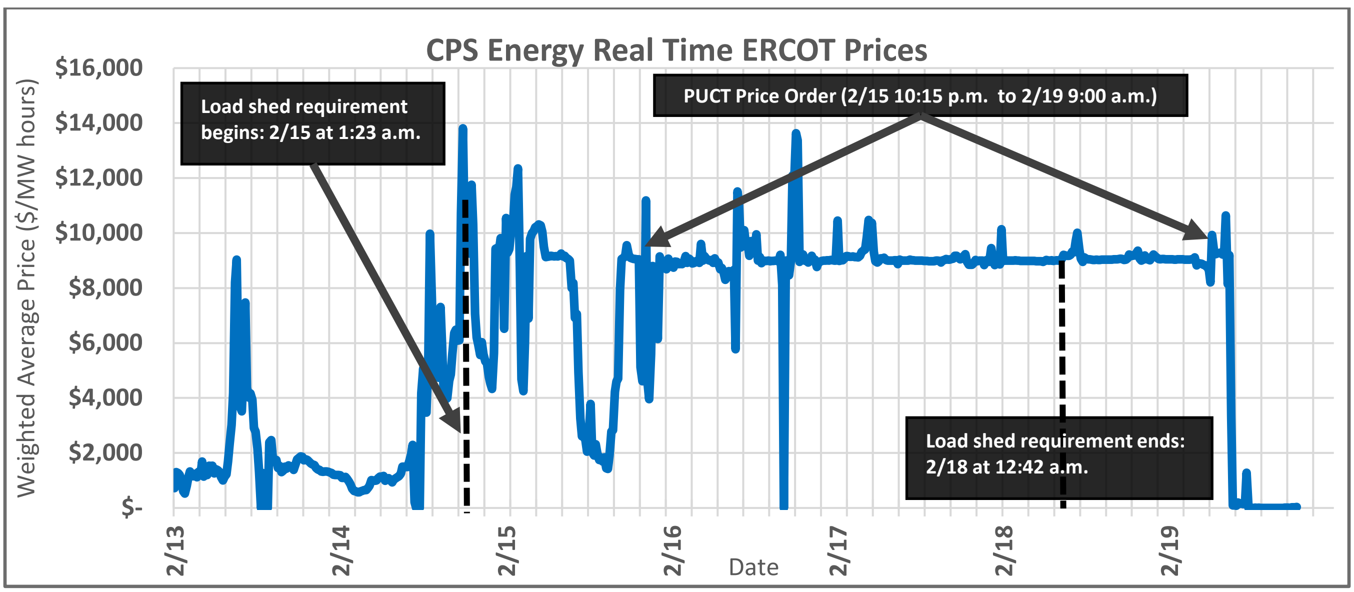

Figure 2

Due to the ERCOT command to load-shed their customers, power producers were offering power for sale into the ERCOT grid. This free market activity is reflected in the 15-minute real time pricing during the day on the 15th of February. As expected, the pricing is volatile and at times drops below the $2,000 per MWh range.

Public Utility Commission of Texas (PUCT), which oversees ERCOT, subsequently issued an order declaring the free market prices being recorded on their system to be incorrect and inconsistent with the fundamental design of the ERCOT market. In support for their intervention in the free market, PUCT states in order No. 51617 the following. "Energy prices should reflect scarcity of the supply. If customer load is being shed, scarcity is at its maximum, and the market price for the energy needed to serve that load should also be at its highest." At 10:15 PM on February 15th, PUCT ignored the free market prices and raised the price of power to $9,000 per MWh, which is the maximum allowed. PUCT held the real time price at $9,000 per MWh until 9:00 AM on Friday, February 19, 2021, even though ERCOT discontinued load-shed orders at 12:42 AM on Thursday, February 18, 2021.

Price manipulation by the PUCT did not incentivize more electricity generation, as the amount of generation capacity out of service remained in the 50,000 MW range until midday on Wednesday, February 17, 2021. Immediate price signals can only be effective if an entity can quickly scale up generation. Electricity producers did not have that option during the storm. While the PUCT understood the tremendous demand for electricity that was taking place during the storm, the PUCT misunderstood the simultaneous limitations on electricity production during that time. In a winter storm as severe as what was experienced, manipulated price signals simply could not make up inadequate reserve capacity, shortage of natural gas, and improperly winterized facilities.

The artificial setting of price of electric power at $9,000 per MWh by the PUCT and executed by ERCOT during the winter storm was economically devastating to CPS Energy and its customers. The table below, Figure 3, details the ERCOT expenses by day for the event and similar ancillary services provided directly from third parties.

Winter Event Transactions											
Revenue (Cost)					In Thousands						
Day	Real Time Market Energy	Day Ahead Market Energy	ERCOT Ancillary Services	Subtotal	Bilateral Ancillary Services	Reliability Deployment / Revenue Neutrality	Resiliency Settlements (3rd Party)	Subtotal	Short Pays & Other	Total Disclosed in Material Event Notices
9-Feb	583	460	(18)	1,025	(12)	16	(18)	1,011		
10-Feb	795	90	(22)	863	(12)	(53)	(3)	795		
11-Feb	3,024	272	(74)	3,222	(28)	(352)	(314)	2,528		
12-Feb	5,749	58	(160)	5,647	(79)	(96)	(142)	5,330		
13-Feb	18,605	-	(2,313)	16,292	(1,658)	63	(1,109)	13,588		
14-Feb	(47,258)	-	(3,679)	(50,937)	(10,776)	446	(1,244)	(62,511)		
15-Feb	(129,152)	-	405	(128,747)	(16,132)	6,269	(2,206)	(140,816)		
16-Feb	(1,164)	(17,932)	(14,184)	(33,280)	(24,180)	29,281	(2,218)	(30,397)		
17-Feb	83,195	-	(24,739)	58,456	(28,016)	12,819	(2,423)	40,836		
18-Feb	(103,451)	-	34,483	(68,968)	(27,916)	(944)	(3,197)	(101,025)		
19-Feb	(16,388)	-	32,296	15,908	(21,248)	(5,251)	(1,362)	(11,953)		
20-Feb	-	-	-	-	(11,558)	10	-	(11,548)		
Total	(185,462)	(17,052)	21,995	(180,519)	(141,615)	42,208	(14,236)	(294,162)	(70,838)	(365,000)

Figure 3[8]

As reflected in figure 3, these transactions could have a $365 million negative impact on CPS Energy. Unfortunately, the indirect effect on natural gas prices when PUCT artificially set the electric power price at $9,000 per MWh inflicted even greater economic harm on CPS Energy.

The manipulated price for electricity is reflected in the inflated market price for natural gas. The chart below, Figure 4, details by day the average prices charged to CPS Energy for natural gas and the total daily charges for natural gas during the storm. By February 17, 2021, CPS Energy was charged an average

[8] RFI 22A and 23A

price of $386 per MMBtu, which is 100 times the prevailing price before the storm. During the storm CPS Energy was charged over $685 million for natural gas.

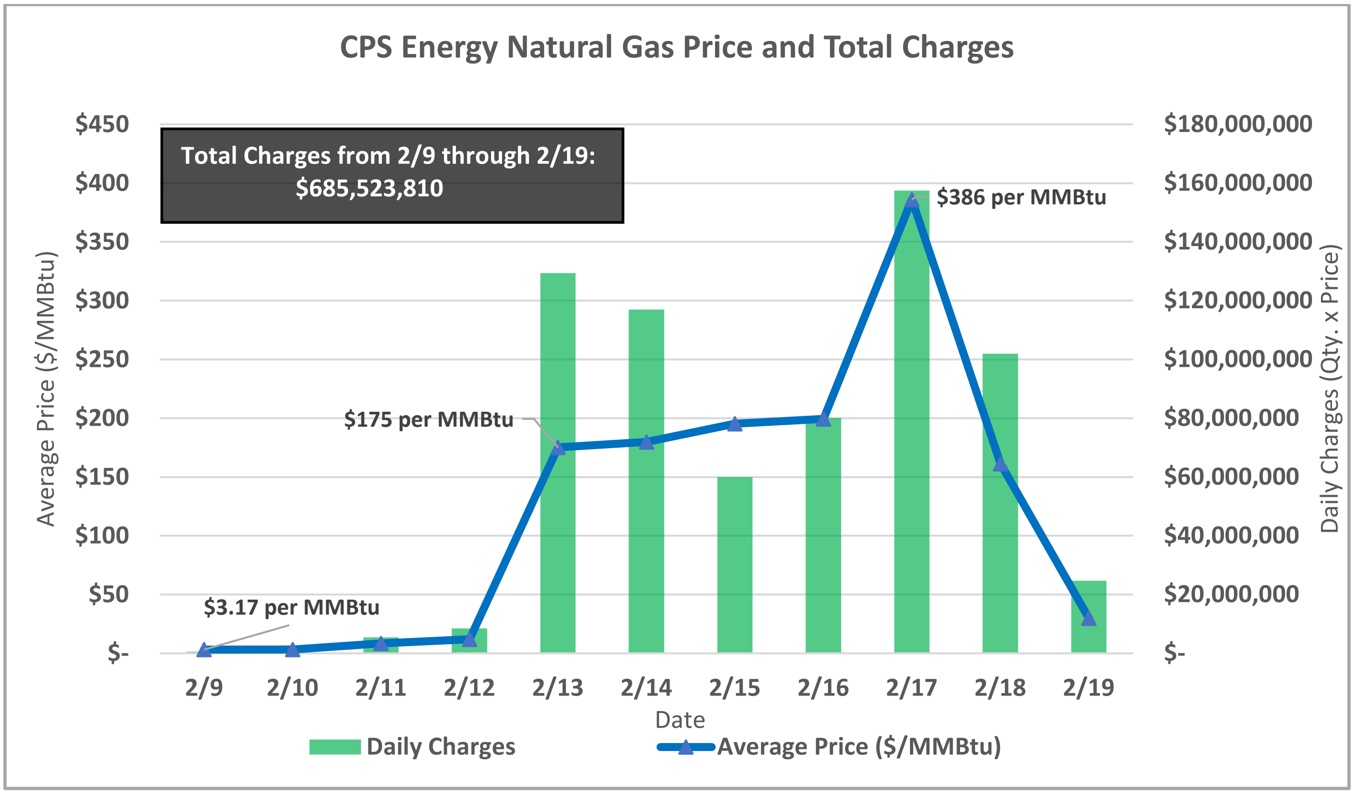

Figure 4

CPS Recommendation 2: CPS Energy reevaluate their strategies and procedures for purchasing and transporting natural gas to assure adequate supplies of natural gas are available to their natural gas generation units critical for firming capacity during a crisis and for natural gas distribution to customers for heating.

CPS Recommendation 3: CPS Energy and the City of San Antonio join with other cities, municipal utilities, and rural electric cooperatives to develop and pass legislation in the 2023 legislative session to eliminate the ability for the PUCT through ERCOT to artificially manipulate the price of electric power and ancillary services on the grid and only allow ERCOT to have administrative and "clearing" authority over next day prices, real-time prices, and ancillary services on the grid.

<u>Power Plant Operating Problems</u>

The baseload coal, and nuclear generation plants did not perform as required during the winter storm and the dispatchable natural gas generating plants did not operate sufficiently to make up for the lost production.

Since the freeze of February 2011, CPS Energy conducted plant studies to identify vulnerabilities, installed heat tracing on sensitive tubing, upgraded insulation and implemented numerous other weather readiness improvements on its plants. CPS Energy conducted its regular winter readiness procedures beginning September of 2020 and submitted a declaration of winter readiness to ERCOT on November 30, 2020. Further, the utility carried out additional actions beginning February 4, 2021 to prepare for the winter storm. These actions are summarized in the responses to RFI 8. However, the extensive weatherization actions taken were insufficient to account for either the demand experienced during the storm or the damage the storm would have on vulnerable plant equipment, as identified in the response to RFI 13.

Immediately after the winter storm, many political office holders declared the failure of the renewable sources of power to be the problem. Based on the prior 3 year average, February daily renewable production CPS Energy could expect renewables to provide only 7.8 % of their generation capacity during the winter storm as indicated in the response to RFI 6. CPS Energy actually received 3.2% of their generation from renewables during the storm. The actual generation received from wind and solar is compared to the average production received in February for prior three years is presented in the following chart (Figure 5).

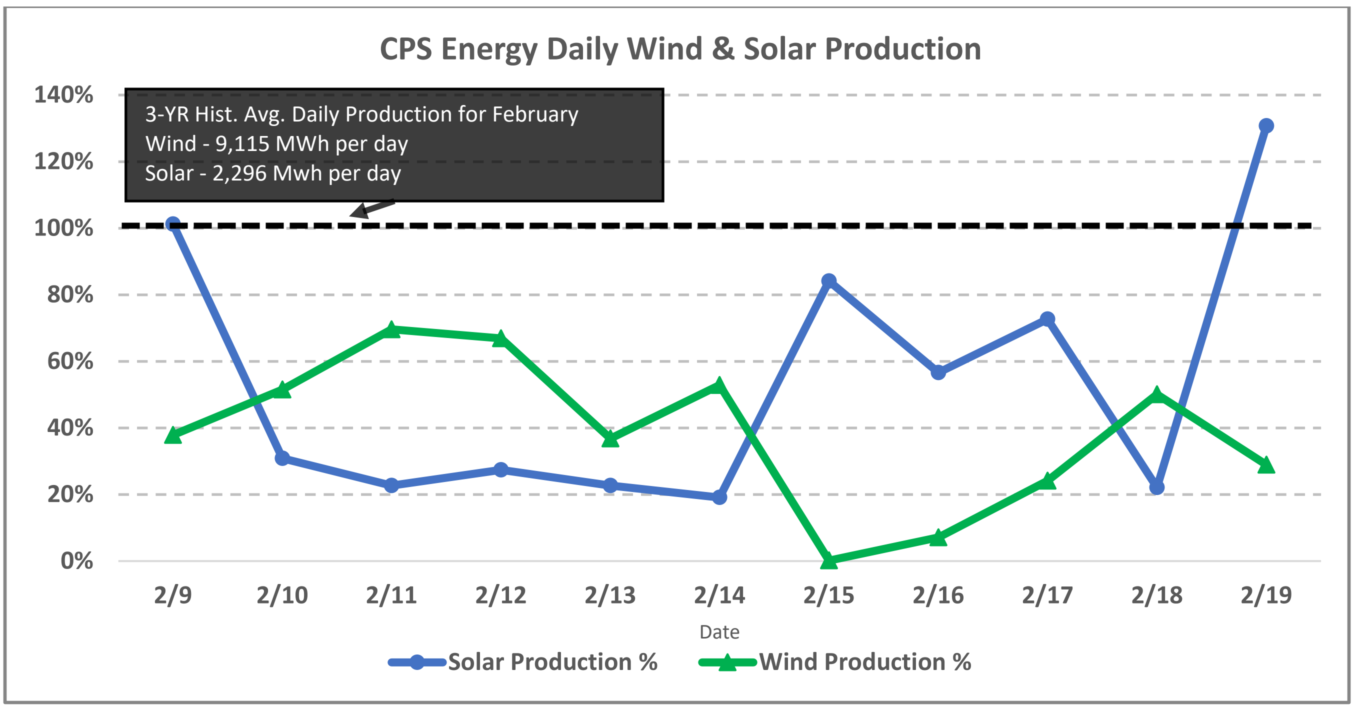

Figure 5

The solar generation enters the storm period at about the three-year average. While it drops quickly with the snow, it recovers almost to the three-year average, except on Thursday, February 18, 2021. The power received from the wind contracts during the event is especially affected during the extremely cold days.

Clearly, CPS Energy was not depending on their renewable contracts to provide a significant portion of their generation during the storm. During a winter crisis CPS Energy must depend on the base load plants, such as the nuclear plant and the coal fired plants, and the dispatchable plants fueled by natural gas, as detailed in the following graph (Figure 6).

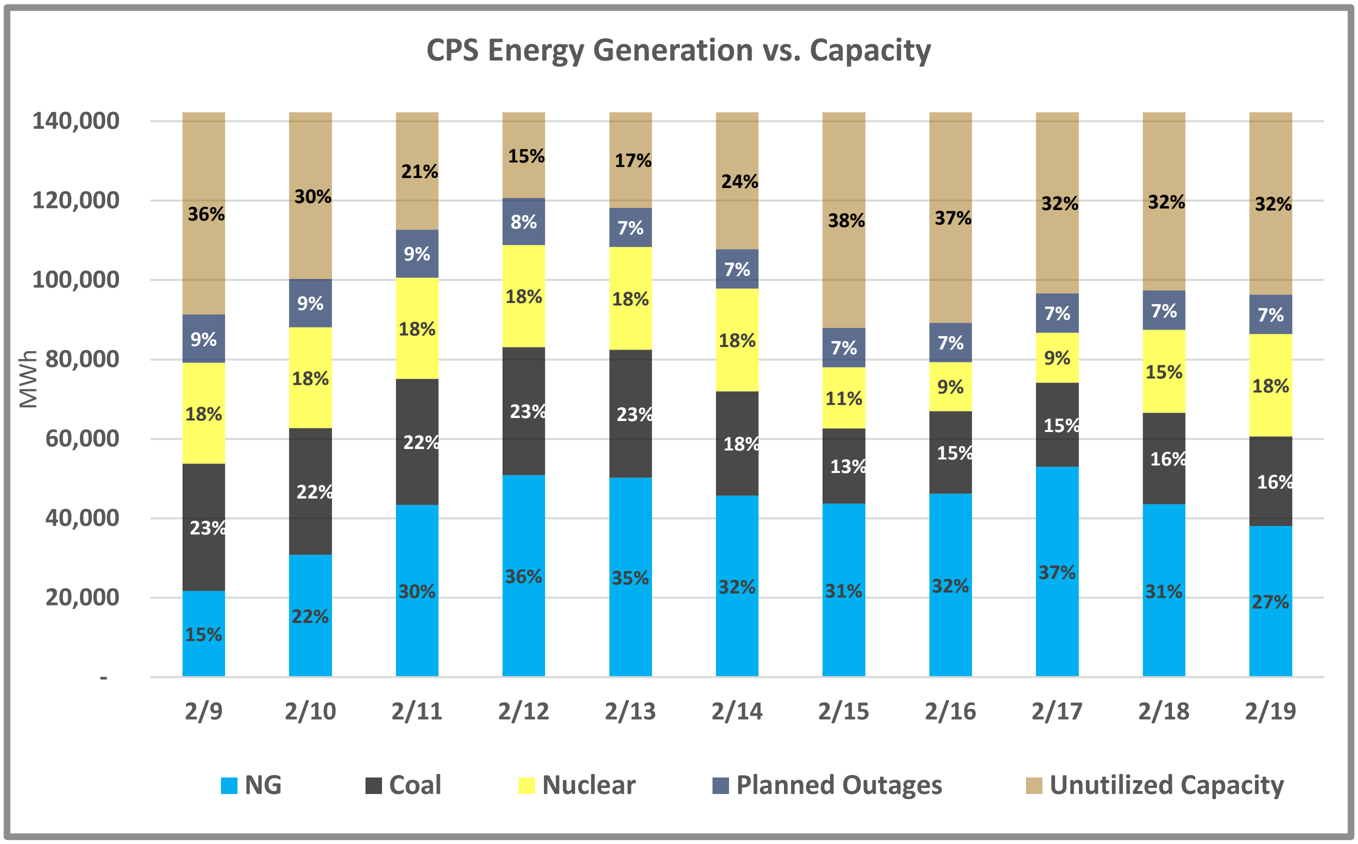

Figure 6

The chart in Figure 6 displays all generation sources other than renewables to provide a complete picture of all expected operating contribution from the base-load and dispatchable plants and unexpected capacity from units scheduled down for maintenance. CPS Energy successfully reduced the unutilized capacity to 15%, by the 12th of February, before the lowest temperatures of the storm arrived. CPS Energy was able to accomplish this by ramping up natural gas fired units and retuning a unit down from scheduled maintenance early. CPS Energy was able to hold that level of utilization through the next day.

On Sunday, February 14, 2021, unutilized capacity started to increase due to the first of two major failures. The first failure was loss of control of the forced air fan feeding the firebox of Spruce 1. The initial forced air fan problem precipitated other problems detailed in the response to RFI 13, leading to a complete shutdown on Monday, February 15, 2021. Spruce 1 was returned to limited capacity by firing the boiler with natural gas but was not returned to full capacity until after the winter event, as illustrated in the following chart (Figure 7).

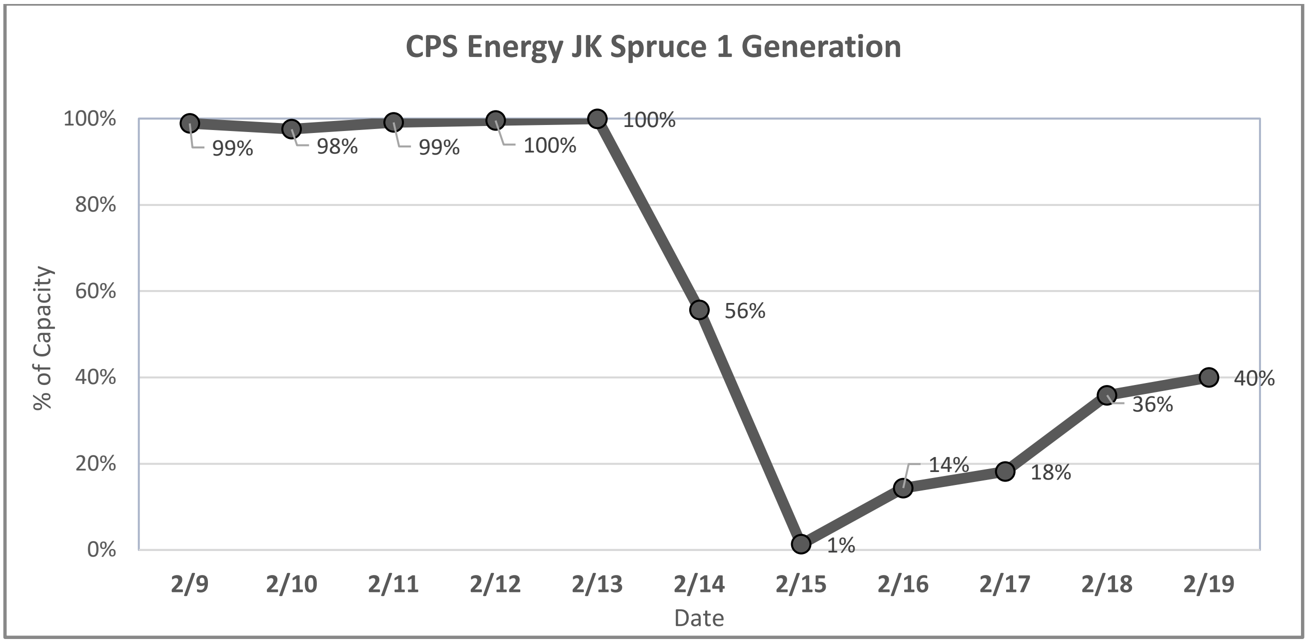

Figure 7

Due to the extended failure, from Sunday the 14th of February through the end of the event on Friday the 19th of February, Spruce 1 lost 58,418 MW hours of production. ERCOT continued to artificially hold the grid power price at $9,000/MWh until 9:00 AM on Friday, February 19, 2021. During that period, CPS Energy could have sold power into the ERCOT grid for $9,000/MWh or avoided purchasing power from the ERCOT grid for $9,000/MWh, powering community homes. Thus, the opportunity cost to CPS Energy for 58,418 MWh at $9,000/MWh is approximately $500 million.

The following day, on Monday, February 15, 2021, as Spruce 1 was shutting down, another major failure occurred at South Texas Nuclear Project 1 (STP 1). An uninsulated water pressure sensor line froze at STP 1. The line was used to monitor the inlet water pressure on the feed pumps to the steam generator. This necessitated the shutdown of STP 1, as represented in the following graph (Figure 8). The line was insulated, and the unit was restarted on Thursday, February18, 2021, and attained full capacity by the next day.

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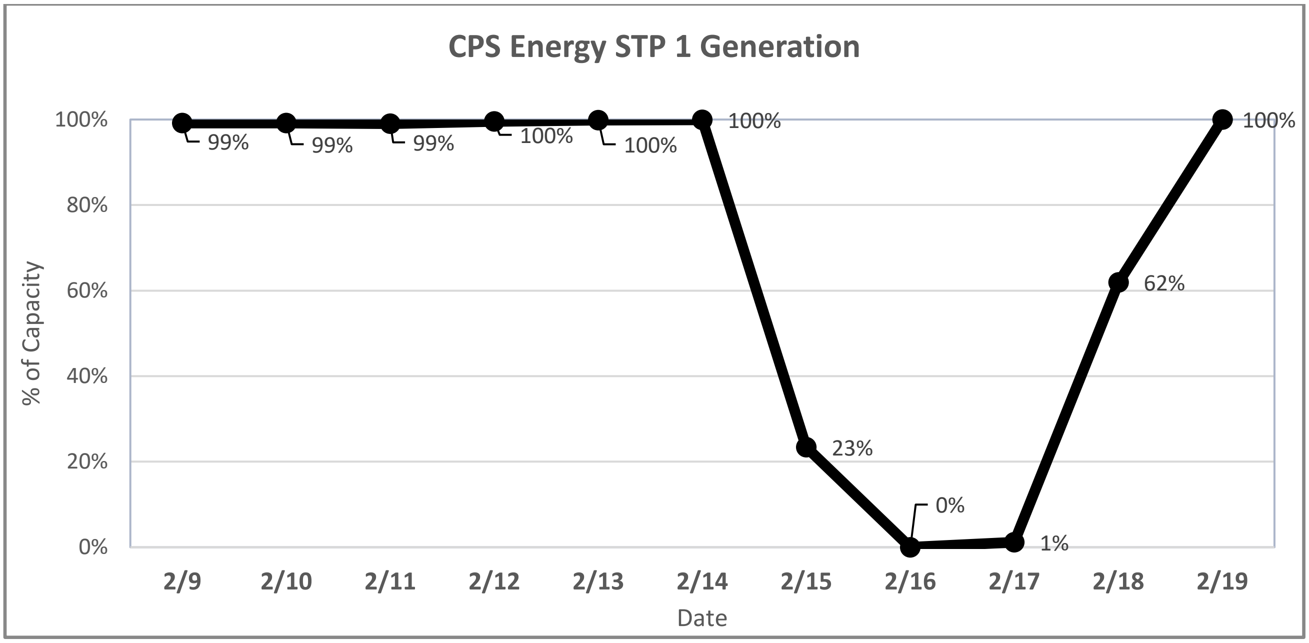

Figure 8

Due to this failure, CPS Energy's portion of the production loss at STP 1 was 40,711 MWh. The loss of capacity was during the period when ERCOT maintained the price at $9,000/MWh. CPS Energy suffered an additional opportunity cost of approximately $350 million. The two failures in critical baseload plants increase the unutilized capacity to 38% on Monday the 15th of February and only recovered to 32% for the remainder of the winter event. The total loss of power due to these two failures was 100,224 MW hours with an associated opportunity cost of approximately $850 million.

During an emergency, it is critical to have natural gas fired generation units available to start up and compensate for lost capacity from renewables and failures at baseload plants. The chart below, Figure 9, shows how CPS Energy successfully ramped up natural gas fired generation capacity from 26% on Tuesday, February 9, 2021, to 61% just before the storm hit on Friday, February 12, 2021. CPS Energy was able to hold the natural gas fired generation between 52% and 63% until Friday, February 19, 2021, when it decreased to 45%. Unfortunately, that the natural gas fired generators were unable to get above 63% utilization of the total natural gas fired generation.

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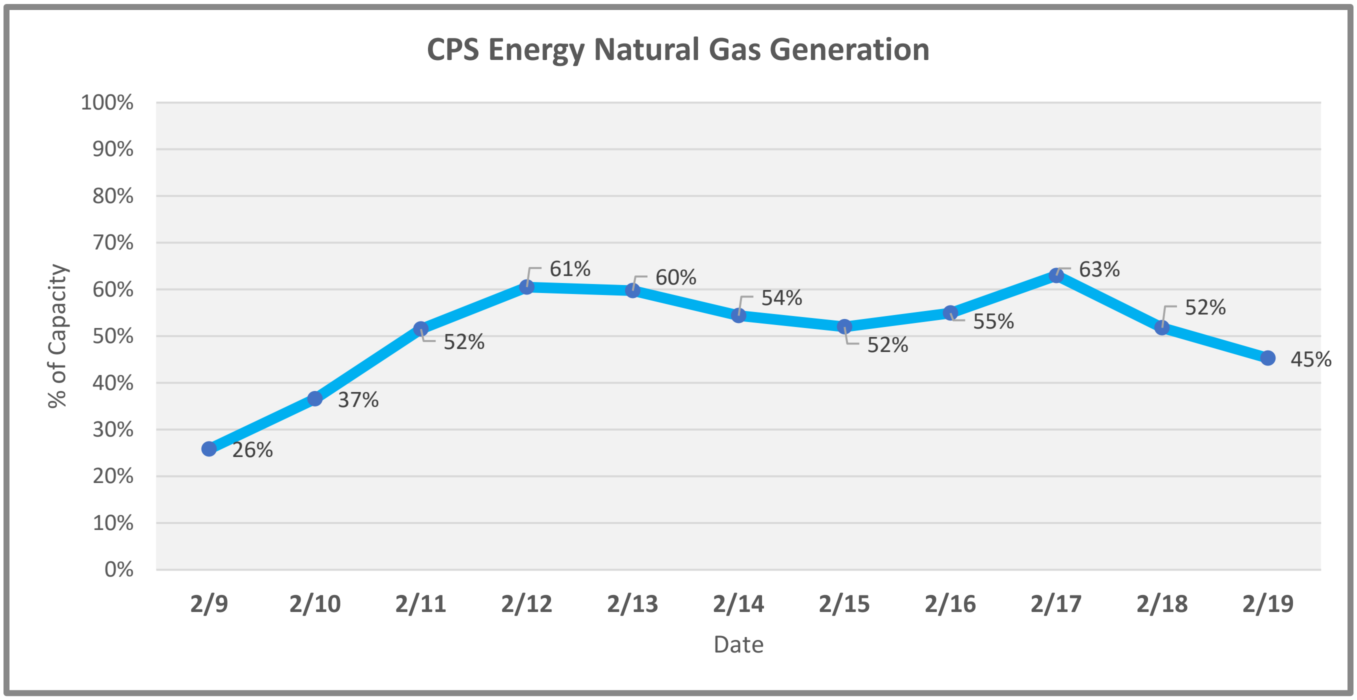
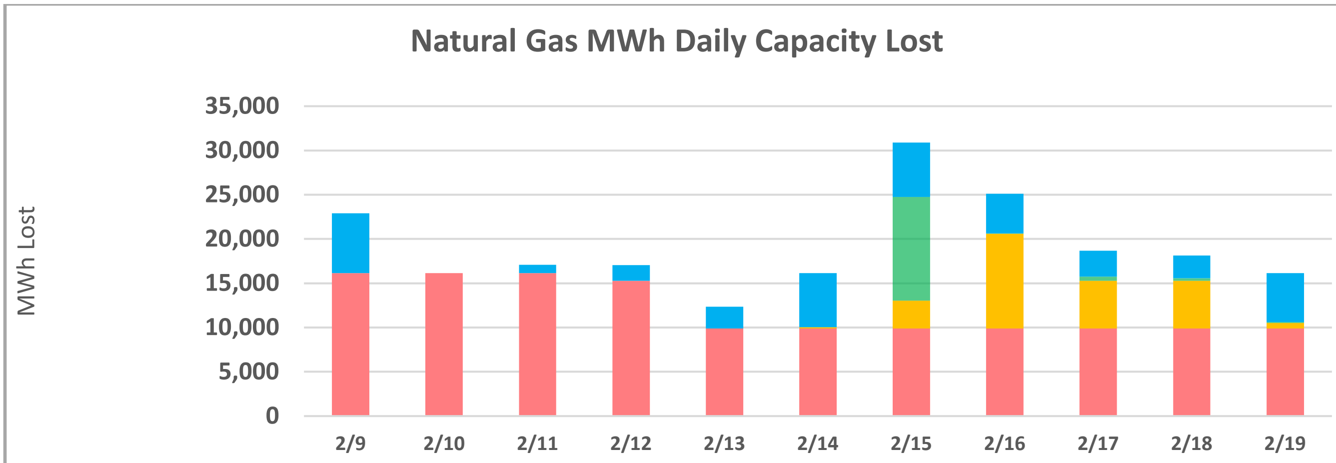


Figure 9

The natural gas fired generation plants lost capacity during the winter event for several reasons, detailed in the chart below (Figure 10). The first reason was planned maintenance. CPS Energy was able to return 6,264 MWh of daily capacity down for maintenance to operation prior to the winter event, but 9,888 MWh of daily capacity continued to be down during the winter event. February is the lowest demand month of the year, but also has the lowest average temperatures. While it might have been reasonable to schedule maintenance in the lowest demand month, perhaps scheduling maintenance according to weather risk might be more prudent in the future.

The critical impact was experienced on Monday, February 15, 2021, when 11,706 MWh of daily capacity was lost to weather events and an additional 6,167 MWh of daily capacity was lost to controls and mechanical. Clearly, controls and mechanical failures were impacted by the extreme weather conditions. To lose a total of 17,873 MWh of daily capacity on the most critical day from the most dispatchable generation source of power is economically and operationally devastating.

On the following day, Tuesday, February 16, 2021, the shortage of natural gas became a major curtailment on generation capacity from natural gas generation units. CPS Energy lost over 25,000 MWh of generation capacity due to the lack of fuel during the winter event.



	2/9	2/10	2/11	2/12	2/13	2/14	2/15	2/16	2/17	2/18	2/19
Controls & Mechanical	6,753	-	930	1,763	2,472	6,106	6,167	4,484	2,927	2,572	5,562
Weather	-	-	-	-	-	-	11,706	35	447	306	81
Fuel Supply	-	-	-	-	-	143	3,144	10,695	5,400	5,375	633
Planned Outage	16,152	16,152	16,152	15,291	9,888	9,888	9,888	9,888	9,888	9,888	9,888

Figure 10

CPS Recommendation 4: CPS Energy should emphasize and refocus on their long and distinguished history of operational excellence. From the outside, one can see how the historical winter storm exposed numerous operational problems across the fleet. However, it is the job of the Board of Trustees and the CPS Energy management to build the team to control what they can control, which is the generation, transmission, and distribution of electric power, and the purchase and distribution of natural gas.

Unequal Distribution of Power Outages

Given the numerous plant problems and the extent of the load-shed required, CPS Energy was not able to manage outages efficiently and equitably among the interruptible circuits.

Late Monday night, February 15, 2021, the ERCOT load-shed demand reached a peak of 20,000 MW. According to the ERCOT report, CPS Energy provided 6.79% of the total load-shed ordered by ERCOT or approximately 1,358 MW. The installed capacity for CPS Energy is 5,943 MW, not including renewables. To put the requirement in perspective, 1,358 MW of baseload and dispatchable capacity is 22.9% of CPS Energy's installed capacity, not including renewables. Since CPS Energy had so many operational problems, it was very difficult for CPS Energy to accommodate the ERCOT demands and serve their customers.

A total of 274 interruptible circuits including a few low frequency circuits were utilized to distribute the load-shed required by ERCOT across the CPS Energy customers. The map below, Figure 11, plots the total time during the event that circuits serving customers were interrupted. The circuits are color coded by the total number of hours that the circuits were not energized due to the load-shed requirements from ERCOT during the winter storm. The total hours of outage by color is detailed in the explanation box in Figure 11. A quick inspection of the map shows that not all interruptible circuits were interrupted on an equal basis. If all circuits had been interrupted on a equal basis the map would not have such a diversity of colors. The white areas represent a combination of critical circuits and low frequency circuits, which were not affected by the load-shed required by ERCOT. The gray areas represent military instillations.

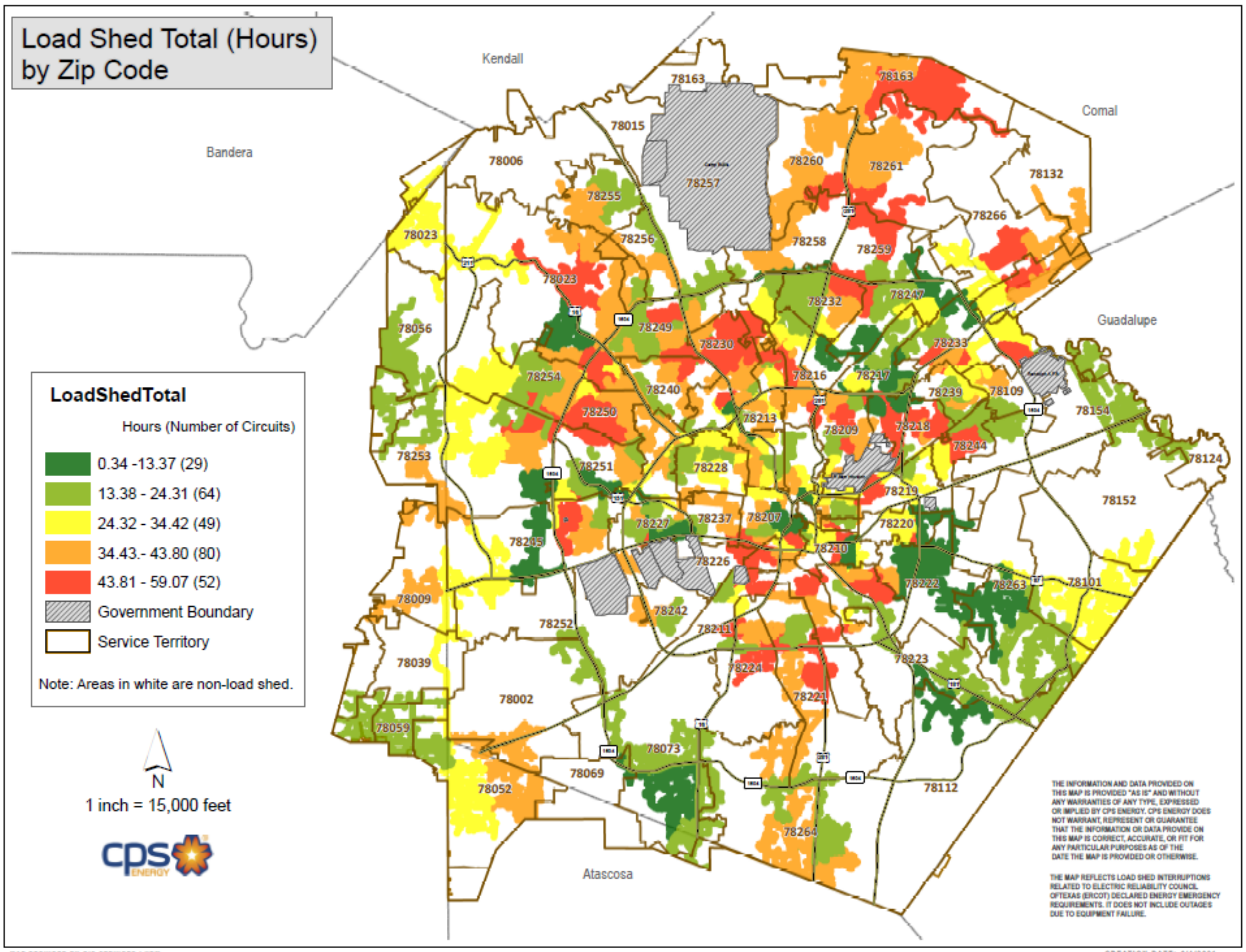


Figure 11

Early in the process of rotating the outages among the interruptible circuits, CPS Energy utilized an automated system. Unfortunately, it did not work because when a circuit was energized, the demand on the circuit exceeded the supply to the circuit, which tripped the circuit. Later in the event, CPS Energy energized the circuits manually with more success.

Immediately after the winter event a great deal of concern was expressed by customers, members of the San Antonio City Council, and groups advocating for social justice that customers in socially and economically disadvantaged areas suffered longer periods of interruption than more affluent zip codes. From a review of the map, it is hard to support that premise. In addition, the more disadvantaged areas contain large areas in white, which represent a combination of uninterruptible and low frequency circuits. The white areas were not affected by the ERCOT load-shed requirements.While the northern and northwestern service areas appear to have had longer and more widespread outages, other areas did experience long total hours of outages as well. Residents in lower income or hipoc areas who potentially experienced comparatively shorter outages may still have experienced significant impacts. Housing stock in these areas is often older, less well insulated, and residents may have less resources to contend with the storm and outages, all of which would make the impact, even of a shorter outage, disproportionately great.

CPS Recommendation 5: CPS Energy should revisit and upgrade the automated rotating outages program so that it is capable of handling larger load shed requirements.

CPS Recommendation 6: CPS Energy should review the options to reduce the size of critical circuits, shift non-critical customers into interruptible circuits, and increase the number of interruptible circuits by reducing the size of non-interruptible circuits. This review of critical circuit load should be undertaken regularly and in coordination with other major critical service providers, such as fire departments, SAWS, and emergency shelter providers.

CPS Recommendation 7: CPS Energy should review opportunities to supply power to SAWS pump stations and other critical infrastructure where critical circuits are not available or to feed these locations from dual circuits.

<u>Communication Problems</u>

Communications before the event did not prepare customers for the potential outages nor the duration of the outages.

On February 10th, 11th, and part of the 12th, prior to ERCOT's call for conservation on that day, CPS issued over ten social media messages and one media release[9]. These messages were informational, marketing oriented, and some were a call-to-action. Informational and marketing-oriented messages informed customers of ensuing coming cold weather and stated that CPS Energy was prepared to handle demand and any outages. The call-to-action messages focused on safe driving during hazardous weather and offered a link for more safety tips.

On the evening of Friday, February 12, 2021, CPS Energy issued two conservation messages and a winter storm warning. These conservation messages were followed by calls to action for safe driving and blood donations.

On Saturday, February 13, 2021, CPS Energy transitioned its messaging, sending calls to action around heater safety, outage reporting, emergency preparedness, and energy conservation. The following day, Sunday, February 14, 2021, CPS Energy moved customer outreach into high gear, issuing over 15 social media messages regarding breakers, road safety, heater safety, and conservation. It also sent automated calls to customers in English and Spanish calling for conservation.

Emergency alert social media messages regarding load shed and rolling outages began after midnight on February 15, 2021.

[9]See CPS Energy RFI 24 https://www.sanantonio.gov/emergency-preparedness/Question-Lists.

ERCOT issued the EEA1 level notification at 12:15 AM on February 15, 2021, and slightly more than an hour had elevated that notification to EEA3, the notification which triggers load shed requirements. Further, the first notification occurred after midnight, after most customers had gone to bed and would not have had a chance to take precautions.

The potential for planned or rolling outages was not communicated by CPS Energy in any of the social media posts or media alerts presented in RFI 24. However, the potential for planned and rolling outages was shared by CPS Energy with the Emergency Operations Center on February 13 and 14 (RFI 24 page. 27). However, that potential was not explicitly communicated to the public by CPS Energy or the EOC.

The seriousness of the conservation message was not conveyed to customers until the day before the outages, which likely limited the reach and effectiveness of the messaging. In addition, the conservation message was issued with multiple messages, many of which were also important to storm preparation, however, some were not. It is also possible that CPS Energy's messaging in the days prior, regarding its preparedness to meet demand during the upcoming cold weather, limited the potential effectiveness of the ensuing conservation requests.

Conflicting messaging along with the lack of advance notice of outages cumulatively had an adverse effect on the credibility of subsequent messaging by CPS Energy during the outages and in their aftermath.

The load shed event was unprecedented in the history of CPS Energy and the City. The lack of power, social distancing practices due to COVID, dangerous road conditions, and extreme cold cumulatively made coordination and collaboration among the City and CPS Energy truly difficult.

CPS Energy did have staff stationed at the EOC during the event. However, based on the communication from CPS Energy during the outages, it appeared that CPS Energy did not effectively communicate with the EOC or SAWS during the emergency. While only CPS Energy employees can restore downed lines and purchase electricity, the emergency itself was felt by the entire community. Therefore, it would have made sense for City and County leadership to have participated in delivering of critical messages, as opposed to leaving that communication only up to CPS Energy.

An emergency of this magnitude requires a widely recognized and trusted messenger for effective communications. A unified front representing the utility, local government and emergency partners is beneficial in that it number one, encourages a coordinated message, making it less likely that the public will receive conflicting or confusing messages; and two, serves to expand the reach of the message as multiple entities combined have a larger audience; and three, in that the appearance of collaboration increases the impression of reliability of the message, making it more likely that the public will listen, share and implement these messages.

CPS Energy and partners should regularly update the emergency communication protocol, as digital communication preferences change quickly relative to how frequently we can expect similar storms. The emergency communication protocols should be developed with contributions from local communication professionals, such as the San Antonio chapters of the Public Relations Society of America and the American Marketing Association. The communications practices should also integrate best practices in crisis communications.

CPS Recommendation 8: Develop a cohesive, comprehensive, and clear emergency communications protocol in collaboration with the City of San Antonio Emergency Operations Center with input from community professionals. In developing the protocol, CPS Energy should consider:

- **8.A Tailoring messaging to what is most critical for the customer's service and safety and focus on what is most relevant to the organization's mission.**
- **8.B Evaluating the effectiveness of calls for conservation and consider how effectiveness can be enhanced, by modifying timing, communication methods, and perhaps even reporting real time progress on conservation.**
- **8.C Issuing an advance notification process to contact each customer when there is a risk of mandatory load shed and rolling outages. These notifications should:**
  1) **Be coordinated with the emergency operations center;**
  2) **Be provided with a reasonable advance notice to prepare and make alternative arrangements;**
  3) **Indicate if customer is on a circuit that is NOT critical and may lose power if rolling outages occur (only possible if notifications are personalized by account); and**
  4) **Advise what the customer should do if they lose power, such as places they can go or whom to call for assistance.**

CPS Recommendation 9: In concert with City and other local agencies develop and implement an emergency readiness year-round campaign, building out the framework of Ready South Texas. The aim should be that residents know how to prepare for an emergency as well as they know the number 911.

B. San Antonio Water System

The arrival of Winter Storm Uri and SAWS' Preparedness

Before Uri's arrival, SAWS was aware of adverse weather predictions, yet, like many organizations throughout the state, did not anticipate the severity or prolonged duration of the extreme weather event. Without knowledge of the storm's severity, SAWS deployed typical cold weather messaging information to its ratepayers - to protect the 3 Ps from freezing: pets, plants, and pipes. In advance of what was believed to be a typical cold weather event, SAWS had staff stationed at key facilities in case a weather-related issue arose, repositioned crews and equipment, stocked up on chemicals and fuel, acquired additional thermal heaters, and provided additional insulation and heat elements on exposed systems.

In the year prior to the storm, SAWS had taken other steps regarding general emergency preparedness. In February 2020, SAWS conducted a Resilience and Risk Assessment (RRA), similar to the City of San Antonio Hazard Mitigation Action Plan, discussed later in Section III.C. The RRA is an all-hazards risk assessment of relevant threats and hazards (malevolent, natural, accidental) to mission critical facilities and assets. Risk results were ranked and evaluated regarding potential mitigation options anticipated to reduce or eliminate risk levels.

In August 2020, SAWS developed an Emergency Response Plan (ERP) to support the findings of the RRA. The Emergency Response Plan incorporates the National Incident Management/Incident Command System (NIMS/ICS) framework. The ERP identifies specific response actions to be taken during an emergency to maintain SAWS' operations, protect employees, minimize disruption to the public, minimize environmental impact, and preserve property. SAWS leadership has communicated that all protocols in the ERP and frameworks were implemented. However, water service was still impeded as a result of the power reliability issues that arose from ERCOT's load shedding requirement and CPS Energy's automatic load shedding program. This is not to imply that SAWS did not have vulnerabilities exposed or major areas of improvements that must be made to ensure the viability of water service in weater-related crises.

Over the years, SAWS made some improvements due to information gathered from a similar freeze event that occurred in El Paso on Tuesday, February 1st, 2011[10]. However, Winter Storm Uri proved to be more significant and damaging than the preparations SAWS made due to the lessons learned from the El Paso storm.

According to SAWS, heat tracing is the best way to keep small diameter pipes from freezing. However, SAWS did not anticipate that its systems would be without power for extended periods of time, so heat tracing provided no benefit and some of the small diameter pipe quickly froze due to the extreme cold. SAWS failed to have draining ports installed in its above-ground piping which led to water freezing in those pipes. It was reported that the below-ground piping throughout SAWS' system had no issues throughout the event regardless of the availability of electrical service. The above-ground piping was at risk and this winter storm event will require weatherization changes to that infrastructure.

The Cascading of Events – Resulting SAWS Service Outages

On Monday, February 15, 2021, at 1:23 AM, the Electric Reliability Council of Texas (ERCOT) issued a load shedding requirement to utilities throughout the state, including CPS Energy, in an attempt to stave off a catastrophic grid-wide failure. SAWS is the largest consumer of CPS' energy. Given the challenges posed to the statewide electricity grid due to heightened demand and diminished generation of electricity, ERCOT demanded that CPS Energy reduce power city-wide via rolling outages. To carry out this request, CPS Energy initiated load shedding by rotating power to interruptible circuits which unintentionally took circuits offline that supply SAWS facilities for pumping and distribution.

SAWS did not have prior notice from CPS Energy that rotating outages would occur. Prior to this winter storm, SAWS had not prepared for the potential threats of widespread grid outages to water pumping stations. Previously evaluated threats, as referenced in the 2015 Hazard Mitigation Plan, were for winter storms far less severe than Uri, to localized or single circuit electrical outages only. Without this forewarning, SAWS could not have adequately informed the community of impending water and sewer service disruptions, and these crisis scenarios were, erroneously, not considered possible..

As a result of the outages at SAWS pumping stations, both equipment for pumping and weatherization tools, such as heat strips, lost power and failed. Consequently, pressure sensors along with above-ground

[10] Hardiman, Mike. "Intense Cold Wave of February 2011." National Weather Service El Paso, TX/Santa Teresa, NM https://www.weather.gov/media/epz/Storm_Reports/Cold11/Feb2011ColdWx.pdf

pipes and ancillary equipment froze, impeding the ability of SAWS operators to assess water quantities in SAWS storage tanks and pipeline pressures at points across the system.

By Tuesday, February 16, 2021, it became evident to SAWS leadership that the effects of the winter storm would be much more prolonged than anticipated. With an inability to determine water pressure due to damaged sensors and gauges, SAWS had to move from automatic to manual operation. Without automated pressure information, crews were dispatched to manually measure pressures at points across the system.

Due of the freezing conditions and the threat of additional load shedding, SAWS made the decision to support the CPS Energy requests to allow rotating power outages at select SAWS pumping stations.

SAWS followed the emergency response protocols outlined in their Emergency Response Plan and the National Incident Management System guidelines. Despite prior preparations, SAWS equipment was vulnerable to the extended loss of electric power and the severe freezing temperatures. SAWS water service is dependent on CPS Energy electrical service. SAWS followed the guidelines established for power outages in SAWS' Emergency Plans, but without power, these plans were not fully effective.

The Cascading of Events – Impact on SAWS Service Delivery

Rolling outages and frozen above-ground pioes were the major factors leading to the ultimate service disruptions of the SAWS system. Operation of the SAWS' system depends on level and pressure monitoring devices. Power failures required staff to be dispatched to stations in order to manually determine level and pressure information. Water service disruptions expanded in the area as ERCOT required additional load shedding by CPS Energy and above-ground pipes froze.

On February 15, 2021, SAWS contacted CPS Energy and requested that their infrastructure be prioritized for electricity service restoration. SAWS had included the University Pumping Station on the CPS Energy list of critical assets but power to the station was disrupted which further exacerbated the water service failures. While many areas began to have their water restored by Thursday, February 18, 2021, the higher elevation neighborhoods north of 1604 did not have their water restored until Sunday, February 21, 2021.

On Wednesday, February 17, 2021 SAWS issued a system-wide boil water notice (BWN) in compliance with TCEQ guidelines. These TCEQ guidelines require the issuance of a BWN in cases where water pressure in a Public Water System drops below a set threshold and a risk of contamination to the water supply arises. SAWS also began planning and setting up bulk water delivery at the more reliable pumping stations and coordinated with the City for bottled water distributions.

By Thursday, February 18, 2021, when most CPS Energy customers had their power restored, SAWS began restoring water for those customers who had lost water service. By Friday, February 19, 2021, bulk water and bottled water distribution sites were up and running. The bottled water for bulk distribution was eligible to be reimbursed by FEMA with the local match funded by SAWS, and the sites were operated by the City of San Antonio. There were widespread concerns among the community that the efforts to initiate bulk water and bottled water distribution were not initiated in a timely manner and unreasonably delayed. On Sunday, February 21, 2021, SAWS restored pressure for all customers. Remaining water issues after this time were not due to problems with SAWS infrastructure, but rather primarily due to frozen or burst pipes and pipelines.

The Impact on Residents Affected by the Outages

Some areas of the City were more impacted longer or more frequently by service outages than other areas. The difference is due to the physical geography of the service area and the design of the SAWS system itself (See Exhibit B for maps of SAWS' service outages). The service area has a 1,400-foot elevation difference from southeast to northwest. A number of external water supplies, such as Vista Ridge, Canyon Lake, Trinity Aquifer Suppliers, serve the northern sectors of the service area. Early in the storm event, the external water supplies in operation experienced power disruptions and were taken offline. Consequently, SAWS shifted water supplies exclusively to Edwards Aquifer water. This shift in supply required SAWS to pump water from the lower-central portion of the service area into higher elevations to the north and west.

SAWS utilized a "ladder climbing" technique to pump water from station to station to move water to higher areas while maintaining a sufficient water pressure level. SAWS' University Pumping Station was the base of this ladder pumping system. When rolling power outages disrupted power to the SAWS' University Pumping Station at UTSA and 1604 every pumping station up the chain was impacted and lost water service capability. This chain of events led to prolonged delays, as SAWS was required to go station by station restoring pumping stations and pressure zones until the whole chain of pumping stations could operate sufficiently. As a result, elevated communities on the Northside experienced the longest delays in water service restoration.

Most of the SAWS stations do not have large generators capable of supplying sufficient power to operate the large pumps moving water. Many SAWS pump stations have small generators for the security, lighting, and for communication infrastructure, but one of the most frequently discussed issues concerning the SAWS service disruptions was the possibility of providing large generators capable of moving water at pump stations. Installing large generators at all stations would be extremely expensive and also requires expansion of the stations, acquisition of real estate, installation of electrical switchgear upgrades, and storage of massive quantities of fuel. SAWS estimates that a generator (or system of generators) for one pump station would cost approximately $10 million, not including fuel storage and additional electrical upgrades. Black and Veatch estimated it would cost $200 million not including the H2Oaks station or fuel storage to add generators (or a system of generators) across the city. Neither of these estimates takes into consideration the costs to provide power to the wastewater treatment plants.

SAWS has indicated that this type of generator (or system of generators) would have potentially been used only one other time in the past 30 years. However, there may be opportunities for SAWS and CPS Energy to partner on this large generator (or generator system) concept building out distributed energy in San Antonio and helping with demand management periods in the summer as well. A distributed energy strategy would obviate the need for generators to sit idle for extremely long periods of time. SAWS and CPS Energy could consider this as a cost sharing opportunity, to include the use and benefit of the generators. This concept must be explored further.

Based on weather forecasts, SAWS expected severe cold and precipitation. However, the cold was much more intense than anticipated. In advance of the storm, SAWS positioned members of their team at critical locations throughout their system. They set up their Operations Control Center in person, transitioning it from a remote center.

As with all systems, unexpected events highlight areas for improvement, and Winter Storm Uri provided that realization to SAWS. SAWS provided a tremendous amount of information to the public via television and social media; however, many homes were without power, so the television messages were not necessarily received.[11] When residents charged their phones in their cars, they often accessed social media as well as the SAWS website to obtain information. SAWS issued over 200 social media posts and dedicated part of their website to information regarding the storm. Robo calls were also used to automatically call as many customers as possible to provide status updates.

Staffing issues arose early on as many customer service operators were working from home, and they too were experiencing rolling power outages. They were imtermittently unable to receive calls or access the internet to respond to online inquiries. In addition to the limited ability to communicate with customers, operators could not get complete and current status information from operational staff concerning the status of the water restoration progress.

As water outages spread throughout the service area, SAWS did not communicate with the EOC. SAWS and CPS Energy maintained constant communications at the leadership level. SAWS did not have personnel at the City's Emergency Operations Center (EOC). Significant announcements, such as the citywide boil water notice, were shared with the EOC after SAWS made decisions and at approximately the same time as the public was notified of those decisions. This did not allow for any coordinated planning or messaging. SAWS had not previously coordinated with the EOC to provide community-wide text alerts to the customers.

In the wake of Winter Storm Uri, SAWS committed to assessing what went wrong, developing recommendations to make infrastructure more resilient and staff more prepared to manage severe weather emergencies. Additionally, SAWS has committed to updating communications, staffing, and equipment protocols to ensure better resiliency. As per this commitment, SAWS leadership conducted an internal audit and commissioned Black and Veatch to assess system vulnerabilities and develop recommendations for improvement.

Additionally, in this vein, SAWS leadership has provided answers to all questions asked by the Emergency Preparedness Committee and made staff available to support our inquiries.

SAWS Recommendation 1: Implement recommendations in the Black and Veatch report.

SAWS Recommendation 2: In conjunction with CPS Energy, identify and place infrastructure required to maintain water and sewer operations to critical facilities on uninterruptible circuits in order to avoid service interruptions.

SAWS Recommendation 3: Coordinate with CPS to determine which SAWS locations must have power generators and/or fuel storage for load reduction events and consider shared uses for generators.

SAWS Recommendation 4: Improve the resilience of current infrastructure with additional weatherization and emergency response equipment as follows:

[11] SAWS RFI 11 - https://www.sanantonio.gov/emergency-preparedness/Question-Lists

4.A Heat strips, hot air blowing tools, additional insulation on large diameter piping – any other similar technology to help with weatherization efforts.
4.B Draining ports for above ground piping. Draining ports would allow SAWS to remove water from its piper prior to them freezing. These are currently being installed.
4.C Software and communication tools to provide real time messages to the City and the public.

SAWS Recommendation 5: Perform routine disaster scenarios with CPS Energy and with the City EOC, such as natural disaster and terrorist attack response simulations. In addition to tabletop exercises, conduct in-person field exercises. The exercises should include City Councilmembers and their staff when appropriate.

SAWS Recommendation 6: Plan and acquire all necessary equipment for emergency water filling locations (bulk water distribution) around the city that can be set up rapidly in times of emergency, and establish messaging to rapidly inform the community of their locations when needed.

6.A Develop procedures with the City of San Antonio and increase joint readiness for bottled water distribution. SAWS and the City should invest in a stockpile of 10-year shelf-life water that can be distributed in emergency situations and rotated out every 8 years to ensure it remains potable.

SAWS Recommendation 7: Consider enclosing select above-ground facilities and infrastructure to protect them from freezing events.

SAWS Recommendation 8: Develop systems and protocols to have one coordinated messaging channel between EOC, SAWS, and CPS Energy for emergencies.

SAWS Recommendation 9: Assign a team to assess, implement, and track the progress of the current recommendations from the Emergency Preparedness Plan and update the plan regularly.

SAWS Recommendation 10: Provide updates to Council offices on a timely basis and establish a singular SAWS point of contact to act as a council liaison during emergency situations.

SAWS Recommendation 11: Update SAWS organizational chart and place online for easy reference.

SAWS Recommendation 12: Increase the number of agents available to take calls during an emergency in lieu of automated machines. Identify critical staff to communicate with the public.

12.A Consider 3rd party live chat services that can be provided critical messaging and provide base intake tasks for customer concerns.
12.B Consider how 311 operators can be integrated with this solution.
12.C Develop a contingency plan for instances when outages disrupt local customer service. Consider 3rd party services based outside of San Antonio being activated in case of emergency.

SAWS Recommendation 13: Create a dashboard that reflects real time outages, infrastructure failures, water pressure issues, and areas under boil water notice with the ability to filter by Council District.

SAWS Recommendation 14: Integrate a SAWS decision maker fully into the EOC with direct and immediate access to SAWS Chief Operating Officer for centralized control/decentralized execution.

SAWS Recommendation 15: Provide relevant emergency preparation information to community members. Assure the information is available and accessible in an emergency (social media, billing inserts, digital bill attachment). Create an Emergency Preparedness Community Guides, including the production of videos instructing residents on topics such as how to turn off water at the meter and store water to flush your toilet when water is not available. (Videos should be on the SAWS website in English, Spanish and ASL)

SAWS Recommendation 16: SAWS and CPS Energy should meet to discuss CPS Energy's compliance with Chapter 25 Subsection C (Infrastructure and Reliability) of the Public Utility Commission's Electric Substantive Rules and discuss the role of SAWS in respect to these compliance measures.

C. City of San Antonio Emergency Operations Center

The Arrival of Winter Storm Uri and City of San Antonio's Preparedness

The City of San Antonio (COSA) is exposed to many hazards, all of which have the potential for disrupting the community, causing casualties, and damaging or destroying public or private property. While it is impossible to prevent a hazard event from occurring, the impact of hazards can be lessened in terms of their effect on people and property through effective hazard mitigation planning and implementation and effective management of emergency activities. To these ends, the COSA developed two plans: The City of San Antonio Emergency Management Basic Plan[12] and The City of San Antonio Hazard Mitigation Plan[13].

The Emergency Management Basic Plan

The Emergency Management Basic Plan outlines the COSA's approach to emergency operations. It provides general guidance for emergency management activities and an overview of COSA methods on mitigation, preparedness, response, and recovery. The plan describes the COSA emergency response organization and assigns responsibilities for various emergency tasks. The objectives of the COSA

[12] "Basic Plan." City of San Antonio, September 2016. https://www.saoemprepare.com/Portals/16/Files/Plans/BasicPlan.pdf.

[13] "Hazard Mitigation Plan." City of San Antonio, 2015. https://www.saoemprepare.com/Plans#:~:text=The%20goal%20of%20the%202015,Mitigation%20Action%20Plan%20(HMAP).

Emergency Management Program are to protect public health and safety and preserve public and private property.

The plan addresses emergency actions that are conducted during all four phases of emergency management: mitigation, preparedness, response, and recovery. Mitigation is intended to eliminate hazards, reduce the probability of hazards causing an emergency situation, or lessen the consequences of unavoidable hazards. See Hazard Mitigation Action Plan discussion below.

Preparedness activities are intended to develop the response capabilities needed in the event of an emergency. Among the preparedness activities included in the emergency management program are:

1. Providing emergency equipment and facilities.
2. Emergency planning; including maintaining this plan, its annexes, and appropriate procedures.
3. Conducting or arranging appropriate training for emergency responders, emergency management personnel, other local officials, and volunteer groups who assist COSA during emergencies.
4. Conducting periodic drills and exercises to test COSA plans and training.
5. Conducting citizen preparedness activities and education in the community.

The focus on the Emergency Management Basic Plan is on planning for the response to emergencies. Response operations are intended to resolve an emergency situation while minimizing casualties and property damage. Response activities include EOC activation, warning, emergency medical services, fire-fighting, law enforcement operations, evacuation, shelter and mass care, emergency public information, search and rescue, as well as other associated functions. If a disaster occurs, COSA will carry out a recovery program that involves both short-term and long-term efforts. Short-term operations seek to restore vital services to the community and provide for the basic needs of the public. Long-term recovery focuses on restoring the community to its normal state.

The Hazard Mitigation Action Plan

The Hazard Mitigation Action Plan provides an opportunity for the city to evaluate successful mitigation actions and explore opportunities to avoid future disaster loss. The Federal Emergency Management Agency (FEMA) defines mitigation as, "any sustained action taken to reduce or eliminate the long-term risk to life and property from hazards."[14] Mitigation differs from emergency preparedness and protective measures, which focus on activities designed to make communities more prepared to take appropriate action in a disaster with emergency response and equipment. Mitigation activities involve alteration of physical environments to reduce risks and vulnerabilities to hazards and make it more cost-effective to respond to, and recover from, disasters.

The focus of the Plan is to mitigate those hazards selected from the State Hazard Mitigation Plan which are deemed to pose a risk to the planning area. In developing the Plan, the City of San Antonio identified thirteen (13) hazards to be addressed in developing mitigation projects. These hazards were identified

[14] "Lesson Overview." Popup: IS-318 Mitigation Planning for Local and Tribal Communities, n.d. https://emilms.fema.gov/IS318/MP0101010t.htm. https://emilms.fema.gov/IS318/MP0101010t.htm

through an extensive process using input from planning team members, and a review of the current State of Texas Hazard Mitigation Plan.

For each of the hazards selected, a detailed risk assessment was conducted as part of the hazard mitigation planning process. The risk assessment enables the City to prioritize mitigation actions based on hazards that pose the greatest risk to lives and property. The risk assessment includes four general parameters that are described for each hazard; frequency of return (how often the hazard occurs), approximate annualized losses, a description of general vulnerability, and a statement of the hazard's impact. Once loss estimates and vulnerability were known, an impact statement was applied to relate the potential impact of the hazard on the assets within the area of impact. Frequency of return is rated from Highly Likely (probable occurrence in the next year) to Unlikely (probable occurrence in the next 10 years). Impact assessments range from Substantial (multiple deaths, or complete shutdown of facilities for 30 days or more, or more than fifty (50) percent of property destroyed or with major damage) to Limited (injuries and/or illnesses are treatable with first aid, minor quality of life lost, or shutdown of critical facilities and services for twenty-four (24) hours or less, or less than ten (10) percent of property destroyed or with major damage).

One of the hazards identified through the planning process is a winter storm. Severe winter storms may include snow, sleet, freezing rain, or a mix of these wintry forms of precipitation. Winter storms and ice storms can down trees, cause widespread power outages, damage property, and cause fatalities and injuries to human life. The risk assessment for a winter storm event was Highly Likely with Minor impact (Injuries and/or illnesses do not result in permanent disability or complete shutdown of critical facilities for more than one week, or more than ten (10) percent of property destroyed or with major damage). This risk assessment also served as a basis for the development of City of San Antonio Emergency Management Basic Plan.

The Operation of the EOC - Direction and Control During an Emergency

Concerning direction and control during an emergency, the Mayor is responsible for establishing objectives and policies for emergency management and providing general guidance for disaster response and recovery operations. The City Manager or designee will provide overall direction of the response activities of all COSA departments. When major emergencies and disasters have occurred or appear imminent, COSA may activate the EOC. The general responsibilities of the EOC are to:

1. Assemble accurate information on the emergency situation and current resource data to allow local officials to make informed decisions on the proper courses of action.
2. Work with representatives of emergency services to determine and prioritize required response actions and coordinate their implementation.
3. Provide resource support for emergency operations.
4. Suspend or curtail government services, recommend the closure of schools and businesses, and cancellation of public events.
5. Organize and activate large-scale evacuation and mass care operations.
6. Coordinate emergency warning and information to the public.

The COSA Emergency Management Coordinator manages the Emergency Operations Center (EOC).

The Arrival of Winter Storm Uri and EOC Operations

The Emergency Management Basic Plan (EMBP) and the Hazard Mitigation Plan (HAP) are designed to help COSA mitigate, prepare for, respond to, and recover from an emergency situation. While the City has successfully negotiated past winter storm events, the event of February 2021 was significantly outside the planning factors that served as the basis for the management and mitigation plans. As a result, mitigation, preparedness, and response actions were insufficient to optimally manage the crisis. The difficulties faced by COSA fall into four major areas: planning, training and exercising, communications, and coordination with public utilities.

Planning provides structure to ill-structured problems and leads to effective action toward efficiently resolving incidents, accidents and emergencies. The current Hazard Mitigation Plan and Emergency Management Basic Plan do not address an event with the intensity and duration of the February 2021 winter storm. This omission resulted in deficiencies in the COSA's mitigation and preparedness actions prior to Uri's arrival and additional deficiencies in response actions during the storm.

COSA Recommendation 1: Update the HAP to include planning for a prolonged winter storm event, prolonged power outages, prolonged water outages, and a combination of the previous three events.

COSA Recommendation 2: Identify backup devices to cellphones and other mobile devices. 4G towers are more reliable than 5G towers, which will fail during major power outages. Be familiar with the plan with COSA telephone and data service providers for the transition to emergency services in the event of provider outages.

COSA Recommendation 3: Prioritize the purchase of generators to ensure key city facilities are able to operate during a major winter or heat event.

COSA Recommendation 4: Evaluate the need to procure tires/chains and other related accessories (light bars, spot lights, etc.) for first responder vehicles.

COSA Recommendation 5: Ensure key city facilities have appropriate inventory of food and water supply for extended emergency events.

COSA Recommendation 6: Develop a plan for emergency housing and lodging for essential employees required to work on site during severe weather events.

COSA Recommendation 7: Establish a hotline for families of essential employees who are working on site needing assistance during the emergency.

COSA Recommendation 8: Identify contingency plans for catastrophic incidents where a significant percentage of workers are not able to work remotely due to power outages.

COSA Recommendation 9: Review utilization of Wireless Emergency Alerts (WEA) to determine if more frequent use is warranted during an emergency. Consider alternative communication for when outages render wireless communication ineffective.

While effective planning forms the basis for successful management of an incident, accident, or emergency, a relevant and challenging training and exercise program is also essential to achieving the desired results. Because the planning documents did not anticipate an event of the intensity and duration of the February storm, the training and exercise programs for key personnel were insufficient to prepare EOC to optimally respond.

COSA Recommendation 10: Develop specific planning, training, and exercises focusing on long term power and water loss due to unforeseen events or scenarios.

COSA Recommendation 11: Enhance city-wide cross-department and cross-discipline emergency response training.

COSA Recommendation 12: Create an annual emergency response table top exercise that includes elected officials, executive leadership for the City, County and Utilities.

<u>The Cascading of Events – The Impact of Decision Making Outside of the EOC</u>

The February storm event began as a typical winter storm hazard and rapidly transitioned into a crisis situation involving prolonged severe weather conditions, prolonged power outages and prolonged water outages. This combination of conditions presented an extremely complex set of challenges for the EOC to command and control and coordinate. While CPS Energy did have a representative at the EOC for the duration of the emergency, decision-making regarding power outages was not made there and did not occur in coordination with the EOC. Rather, the utility participated in the twice-daily EOC calls and provided general information – "ERCOT has required us (CPS Energy) to shed X amount more load" – rather than specific information about which circuits would be powered down and when. This unilateral decision-making made it difficult for the EOC to deploy coordinated resources to targeted areas. It also prevented the type of localized communications that could have allowed affected customers to plan accordingly. City leaders and the public were unable to understand the rationale behind such decisions, especially when the public communications from CPS Energy were inconsistent with their personal experiences. If, by contrast, CPS Energy's load-shedding decisions were done in concert with emergency managers and city leaders, decisions about where to locate warming centers could have been based on an awareness of the critical circuits that were least likely to lose power. Ideally, the load-shedding could have been scheduled in a way that, combined with specific public messaging to affected areas, allowed for proper planning by affected customers. For example, advanced notification of when energy was to be restored – even if only for short durations – would have given the EOC's Joint Information Center the type of information that it could share with the public and to City Council members and County Commissioners for dissemination to their constituents. When water outages began to spread throughout the city, SAWS' decision-making was similarly disconnected with the emergency response. The San Antonio Water System did not have any staff at the EOC, and significant announcements, such as the citywide boil water notice, were shared with the EOC at approximately the same time they were being made publicly, not allowing for any coordinated planning or messaging.

During complex emergencies such as Winter Storm Uri, effective command and control is essential to achieving the most successful outcomes. Effective command and control is dependent on precise alignment of responsibility and authority. While the EOC was responsible for effectively deploying COSA resources and providing timely, accurate, and coordinated information to the public, the EOC lacked the authority to direct the public utilities to provide the necessary information that would have facilitated EOC's command and control responsibilities. In future contingencies, this mis-alignment of responsibility and authority could have even more serious consequences than were experienced during the February event.

COSA Recommendation 13: COSA should adjust the relationship with CPS and SAWS that provides, during certain contingencies, authority for COSA to exercise effective command and control.

COSA Recommendation 14: CPS Energy's load-shedding decisions should be made in concert with emergency managers and city leaders.

COSA Recommendation 15: SAWS should station a staff person at the EOC during a water-related emergency.

COSA Recommendation 16: SAWS water shortage mitigation decisions should be made in concert with emergency managers and city leaders.

<u>The Impact on Those Affected by the Outages</u>

The EOC is designed to be both a command-and-control center and a coordination center. Both of these functions depend on the flow of accurate and timely information and situational awareness. This information flow is dependent on an effective and efficient communication system. During the February event, communication within the EOC was insufficient to provide for optimal command and control and coordination.

COSA Recommendation 17: Ensure all city departments are communicating to the public through the Joint Information Center (JIC) to ensure consistency in messaging.

COSA Recommendation 18: Ensure CPS and SAWS communications are coordinated through the JIC to improve situational awareness for all entities involved.

COSA Recommendation 19: Coordinate daily media briefings by and between COSA, County officials, CPS and SAWS.

COSA Recommendation 20: City 311 and CPS/SAWS Customer Service Call Centers should develop protocols to enhance the customer experience for the community including extended hours.

COSA Recommendation 21: In addition to the daily emails from the City Manager to City Councilmembers, the Executive Leadership Team should maintain daily communication with their assigned council members to keep them informed of emergency status.

COSA Recommendation 22: Daily e-mails and messaging from the City Manager to the City Council should contain a high-level summary with key takeaways in addition to the detail report.

COSA Recommendation 23: The impact of CPS rotating outages should be clearly communicated and coordinated with COSA and SAWS to determine operational/service impacts more comprehensively.

COSA Recommendation 24: Identify a situational awareness platform that can display evolving information remotely from operational teams to leadership.

D. The Impact on the Community

The Committee has addressed the how it happened with respect to each focus area, CPS Energy, SAWS and the EOC. Understanding the sequence of events is necessary in order to apply the lessons learned on how to reduce and avoid outages in the future during extreme weather. This technical understanding alone is insufficient to comprehend the full impact of Uri and the subsequent effect of the outages on the City of San Antonio and so many other Texas residents. We must consider the people.

As residents experienced water and power outages, some were able to find alternative lodgings at hotels or the homes of friends and family while trying to stay safe and avoid both the exposure to and the spread of the coronavirus. Others found themselves stuck at home. The dangerous, icy roads led to auto accidents and injuries. It did not take long before travel was impeded and roads were closed for safety reasons as access to grocery stores, healthcare, and employment became restricted and for some cut off.

Impacted households, some of which had indoor temperatures as low as thirty (30) degrees Fahrenheit, went to great lengths, sometimes to the point of significant harm, to stay warm and survive in the frigid temperature within their homes. Some resorted to burning the chemically-treated wood of chopped up furniture inside the home and running cars in garages for heat, risking carbon monoxide poisoning.

In addition to the extreme cold, residents were navigating their way around, often in darkness, sustaining concussions, sprains, broken bones and other injuries. And, even after the water supply was restored throughout the service area, many residences and businesses experienced sustained water service disruptions due to frozen and damage pipes. Some San Antonio residents experienced water interruption for more than one week.

San Antonio's most vulnerable, its seniors and other medically vulnerable residents—particularly those in home or facilities that were without power—were put at heightened risk of pneumonia, hypothermia, and frostbite among other ailments by these extremely cold temperatures. While seniors at assisted living facilities were impacted by service outages, seniors who are homebound faced greater risks due to having less proximal support. Still other seniors who were able to stay with friends or family, or who relocated to other alternative housing to escape the loss of power and water had to manage the increased risk of leaving their pod and exposure to COVID-19. This is in addition to the fact that San Antonio seniors traversing icy sidewalks and walkways are at greater risk of serious injury from a slip or fall.

San Antonio's medically vulnerable residents faced the compounding of medical problems with impeded access to medical care or electronic devices not to mention the anxiety, fear, and uncertainty many faced wondering if and when the power would come on next or when the water would flow. Individuals with diabetes faced additional health risks due to the decreased circulation caused by the cold and an inability to attend dialysis sessions. Those who rely on life-supporting medical devices such as ventilators or frequent medical appointments faced the threat of medical emergency. Many residents facing these circumstances had to make the difficult decisions between either waiting for electricity to resume or getting on the roads to find a way to power their devices.

SAWS, CPS Energy and the City's 311 call lines overflowed with questions from concerned residents, who found it difficult to get a hold of a live representative who could provide answers or connect them with services and essential information. Councilmembers and their staff navigated their own District outages, conducted check-ins with family members who may have been in jeopardy, and attended to new tasks beyond their traditional roles in order to coordinate critical supplies, donations and volunteer deliveries. Additionally, team members worked to connect with local nonprofits, neighborhood leaders, and local governments within Bexar County and coordinate the allocation of essential supplies to neighbors in need.

The winter storm seemed to leave no sector of San Antonio untouched by its cold. Businesses, many still working to overcome the adverse economic effects of the COVID-19 pandemic, were also impacted by weather-related closures, power and water outages, shortages of available staff, and a widespread inability to connect with their customer base. Large San Antonio corporations had to reduce their energy usage and slow down production, impacting their bottom line and further adding to the supply chain disruptions caused by COVID-19. Many sustained damage to water pipes and experienced flooding damage on their premises. Some businesses experienced worker shortages after the Winter storm had passed while many employees missed work to address property damage, family concerns, and other areas of fallout.

Notably, there were some businesses whose doors remained open while they, undeterred by these challenges, continued serving food and providing supplies to the public. A viral photo of exhausted employees at a San Antonio business conveyed to the nation the sacrifices and taxing work of employers and employees who went above and beyond to serve fellow residents during Winter Storm Uri. From first responders, city staff and utilities frontline workers to nonprofits, media partners, and local business leaders, countless individuals took significant risks to look after their neighbors and help respond to the crisis during and after the event. Whether it was the sharing of details on how to (1) accumulate snow for potable water, (2) work gravity flushing toilets, or (3) keep pets, pipes, plants, and people safe from the elements, media partners amplified critical information and provided insights on managing the risks of and damaged caused by the severe weather.

Firefighters, police officers, and EMS first responders, who faced hazardous roads conditions continued to serve the City of San Antonio, putting out fires, delivering emergency supplies, and responding to those in need of medical attention. Firefighters adapted to the challenges of putting out fires while fire hydrants were frozen, calling audibles to shuttle in water, save lives, and mitigate property damage. Some frontline CPS Energy and SAWS workers camped out in their cars or at the facilities where they were stationed for days in order to provide on-site support and react more quickly to situations and directions in real-time. Utility workers braved the elements to restore utility services as quickly as possible to help keep residents safe. Neighborhood leaders, engaged their fellow neighbors, and community organizations to head food and supplies distributions along with volunteer check-ins teams to ensure that those in their area were accounted for.

Local government officials worked together to make others aware of unique initiatives led by businesses, governments, nonprofits, and community groups sharing tools and tactics for response and recovery. Local businesses aided in water and supplies distribution. VIA Transit staff navigated the dangerous roads to help pick up residents and transport them safely to warming centers.

V. CONCLUSION

The response was full of challenges and recovery was not ideal. In retrospect, there are a number of things that could have been done differently, even though there were many circumstances beyond the control of the City, CPS Energy, SAWS and the EOC. What is clear now is that there was a cascading of events. One major disruption caused by the weather resulted in disruptions to the City's infrastructure systems. In the course of managing the effects of Winter Storm Uri, decisions made by one entity affected the another entity's ability to respond, amplifying the intersectionality of CPS Energy, SAWS and the EOC in the daily lives of the residents of the area. Whether the City of San Antonio next faces a weather event, a cyber attack or some other disaster or hazard, Uri has heightened our awareness and the need to explore the City's resiliency under such circumstances.

As the City's systems becomes more interconnected, and interdependence continues to grow across the city, state, nation and world, the likelihood of cascading events during a time of disaster or hazard are likely to continue. It is imperative that the City of San Antonio and its residents do what can be done to minimize the negative impacts when such an event occurs. The Committee's proposed recommendations are designed to help move the conversation along and to encourage leadership to perhaps reach beyond the current and more traditional emergency preparedness framework.

Though this Committee contains a significant amount of talent and skill, its expertise does not compare to the talent and skill sets of those who comprise the leadership of this City and its energy and water providers. With their respective specializations and industry specific insights, they have the ability to build on these recommendations and to continue the work necessary to better prepare and respond to future significant emergency events with changing conditions and cascading impacts.

The work of the CEP has helped to shine a spotlight on the vulnerabilities discovered during Winter Storm Uri and to identify ways to mitigate exposures and fortify systems and infrastructures. The delivery of this report concludes the work of the Community Emergency Preparedness Committee. With this better understanding, the City, its utilities and partners, along with the residents of San Antonio, can begin to better position the City of San Antonio for what may come next.

Exhibit A – Comprehensive Timeline

- **Thursday, February 4th –**
    - CPS Energy took measures to begin to prepare for the upcoming winter weather (summarized in CPSE RFI 8)
- **Tuesday, February 9th –**
    - CPS Energy begins to ramp up natural gas fired generation capacity, bringing it from the 26% recorded that day to 61% by Friday, February 12th (the weekend before the storm hits)
    - Emergency Operations Center, already at Level III activation (increased readiness) due to the ongoing local response to COVID-19, receives National Weather Service update on upcoming severe weather
    - SAWS began to share warning messaging about the upcoming winter weather and protecting the 3 P's–pets, pipes, and plants
- **Wednesday, February 10th –**
    - CPS Energy begins to issue a series of social media messages and a media release. These messages included information on the upcoming cold weather and a call to action focused on safe driving and cold weather safety tips (this continued Friday, February 12th)
    - First community situational awareness webinar was held with City, State, Federal, Private and Non-profit partners
- **Thursday, February 11th –**
    - EOC continued to monitor the weather event and began developing situation reports, which continued throughout the event
    - ERCOT issued their first power demand warning
- **Friday, February 12th –**
    - CPS Energy issued two conservation messages and a winter storm warning
    - State of Texas issued Disaster Declaration
- **Saturday, February 13th –**
    - EOC increased activation Level from III to a Level I (maximum readiness). The Incident Management Team (IMT) and San Antonio Office of Emergency Management (SAOEM) staff began working in-person and remotely
    - A joint City-County Disaster Declaration was issued
    - CPS Energy transitioned messaging to focus on heater safety, outage reporting, emergency preparedness, and energy conservation
    - While CPS Energy did not share messages about a potential for planned or rolling outages with ratepayers, it did share the concern with the City of San Antonio Emergency Operations Center (EOC) for the first time on the 13th and again the following day
- **Sunday, February 14th –**
    - Temperatures in San Antonio dipped below freezing where they remained until midday February 17th
    - Out of concern for potential disruptions, SAWS deployed staff to several pumping stations and distribution sites
    - San Antonio Police Department (SAPD) activated Ice Plan, closing streets and highways in coordination with TxDOT and Public Works. A Wireless Emergency Alert (WEA) on highway closures was sent to the public
    - EOC began discussions on potential warming centers
    - CPS Energy Spruce 1 Generation began to experience loss of control of the forced air fan that feeds the generator's firebox

- CPS Energy customer outreach kicked into high gear with the issuance of 15 social messages regarding breakers, road safety, heater safety, and conservation. It also sent out automated calls to customers in English and Spanish calling for conservation
- **Monday, February 15th –**
  - 12:15 AM – ERCOT issued Emergency Operation Level 1 notification
  - 1:20AM -1:23 AM – Due to widespread generation capacity failures, ERCOT declared Emergency Operation Level 3 (EEA 3), issues load-shedding requirement, and orders grid participants to reduce electricity distribution to their customers by 10,500 MW
  - In response to this requirement, CPS Energy activated the automated load shedding systems; San Antonians began to experience the first waves of rolling outages
  - CPS Energy shared emergency alerts on social media regarding the ERCOT load shed requirement and ensuing rolling outages
  - 1:53 AM – ERCOT came within seconds of a system wide failure
  - For CPS Energy, 11,706 MWh of daily capacity was lost due to weather events and an additional 6,167 MWh of daily capacity was lost to controls and mechanical
  - Spruce 1 Generation Plant failed completely and was returned to limited capacity on the same day
  - South Texas Nuclear Project 1 (STP 1) was forced to shut down due to the freezing of a water pressure sensor (inability to accurately gauge pressure necessitated the shutdown)
  - SAWS made the decision to support the CPS Energy load shedding requests that allow rolling outages at select SAWS pumping stations. However, several other pumping stations lost power because of the rolling outages. These sites were not anticipated to be downed when SAWS allowed the request
  - SAWS water pumping and distribution infrastructure was impacted by CPS Energy's automatic load-shedding program. Specifically, equipment for pumping and weatherization tools such as heat strips were disrupted by the power outages, and pressure sensors, above-ground pipes, and ancillary equipment froze
  - SAWS began sharing messages to inform the public that the rolling outages are affecting SAWS pump stations
  - Conversations of opening warming centers at the City Manager level began, but electricity and water reliability were an issue
  - 10:15 PM – Public Utility Commission of Texas (PUCT) raised price of power to $9,000 MWh (the maximum allowed) to incentivize providers to put as much power on the grid as possible
- **Tuesday, February 16th –**
  - The shortage of natural gas began to become a major curtailment on generation capacity from natural gas units
  - It became evident to SAWS leadership that the effects of the winter storm would be much more prolonged than anticipated
  - With an inability to determine water pressure due to damaged sensors and gauges, SAWS had to move from automatic to manual operation. Without automated pressure information, crews were dispatched to manually measure pressures at points across the system
  - SAWS shared online messaging that informed community of the impacts to SAWS services
  - Henry B. Gonzalez Convention Center Warming center opened
    - VIA and Northside Independent School District began providing transportation to the warming center
    - EOC coordinated with VIA and SAHA to have SAHA residents transported to hotels
  - Regional Medical Operations Center (RMOC) was fully activated. The RMOC is collocated at the EOC and allows coordination across all Emergency Medical Services (EMS) agencies, hospitals, public health representatives, and emergency management leadership
- **Wednesday, February 17th –**
  - City Council held a special public meeting online where SAWS and CPS Energy provided updates

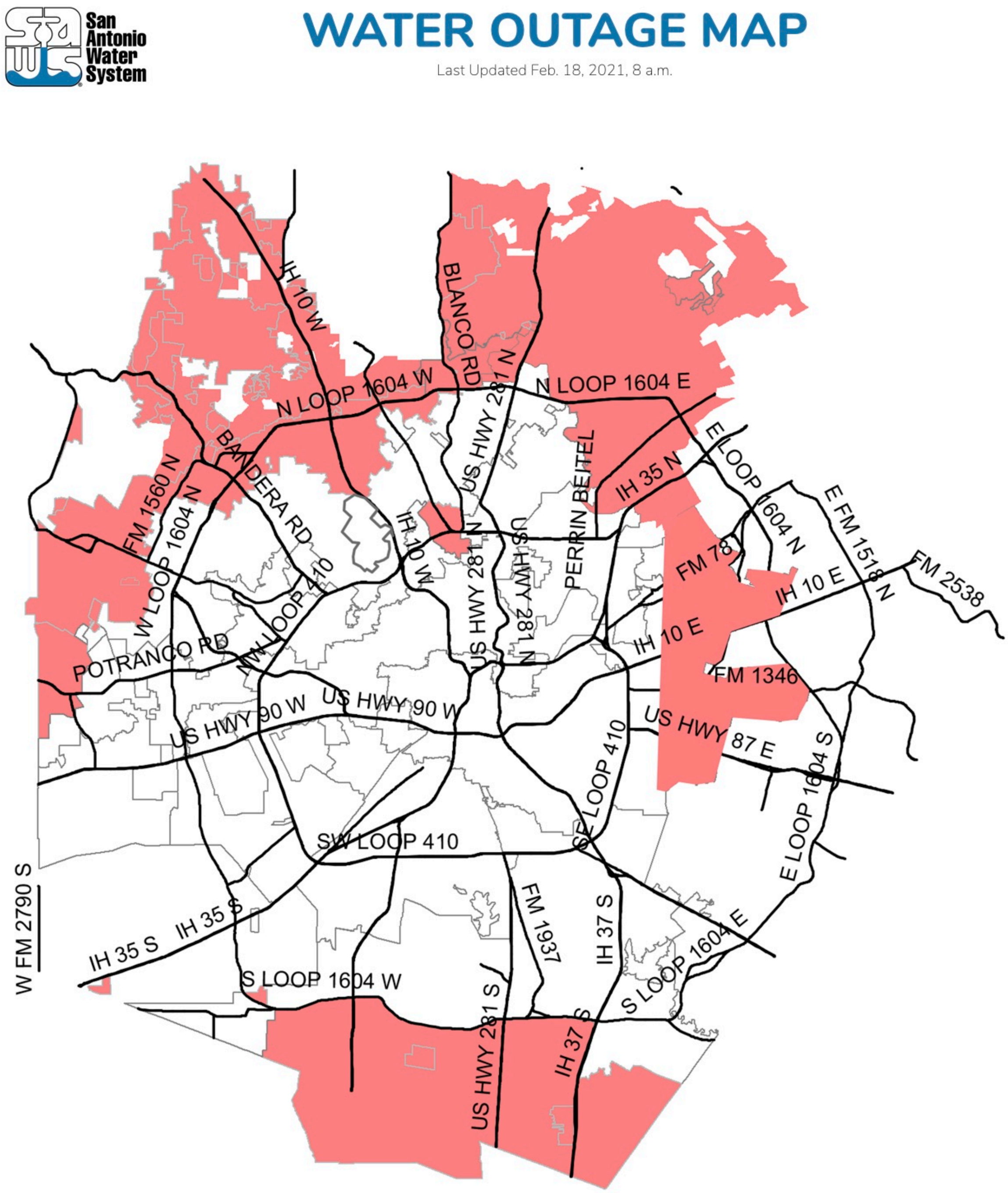
- The heightened loss of generation capacity remained in the 50,000 MW range until midday February 17th when temperatures became more moderate
- CPS Energy was charged an average price of $386 per MMBtu of natural gas which was 100 times the prevailing price before the storm
- SAWS issued a City-wide boil water notice (BWN) in compliance with TCEQ guidelines, which requires the issuance of a BWN in cases where water pressure in a Public Water System drops below a set threshold and a risk of contamination to the water supply arises
- SAWS began planning and setting up bulk water delivery at the more reliable pumping stations
- City of San Antonio begins coordination with SAWS for bottled water distributions
  - City ordered 500,000 cases of bottled water in response to the BWN
  - EOC requested bottled water through the State of Texas
- SAWS began sharing water outage maps
- Strike teams were created for nursing homes, with City providing oxygen refills and assisting with generator repair
- 311 began extending operations through midnight

- **Thursday, February 18th –**
  - STP 1 Generation Plant was restarted
  - Nearly all San Antonians had their power fully restored
  - SAWS restored water service for nearly all areas (except for those with higher elevations located north of 1604 or those whose outages were a result of burst pipes)
  - SAWS non-potable water sites opened
  - Winter weather updates added to Mayor and Judge nightly briefing
- **Friday, February 19th –**
  - 9:00 AM – PUCT ended artificially elevated price of power, dropping the $9,000 MWh rate to prevailing market rate
  - STP 1 Generation Plant resumed full capacity
  - Bulk water and bottled water distribution sites began to be up and running by the afternoon
  - San Antonio food distribution sites opened
  - Water and food delivery to vulnerable populations began
  - Warming Center was closed
  - SAPD ICE Plan was deactivated
- **Saturday, February 20th –**
  - EOC activation decreased to Level III
- **Sunday, February 21st –**
  - Most areas (except for homes and businesses impacted by burst pipes) have their water services fully restored
  - Texas Military forces (TMF) and National Guard forces arrived to assist City with bottled water distribution
- **Monday, February 22nd –**
  - Mayor announced the creation of the SAWS' community Pipe Repair Fund to help vulnerable residents
- **Tuesday, February 23rd –**
  - SAWS lifted the boil notice for all of Bexar County
  - COSA launches an Emergency Resource Call center and website to assist residents affected by the storm. Center helped residents navigate the disaster assistance programs available through FEMA, Small Business Administration, and SAWS
- **Wednesday, February 24th –**
  - Emergency Resource Call Center and City of San Antonio Department of Human Services Benefits Navigators (case managers who specialize in connecting residents with services) were

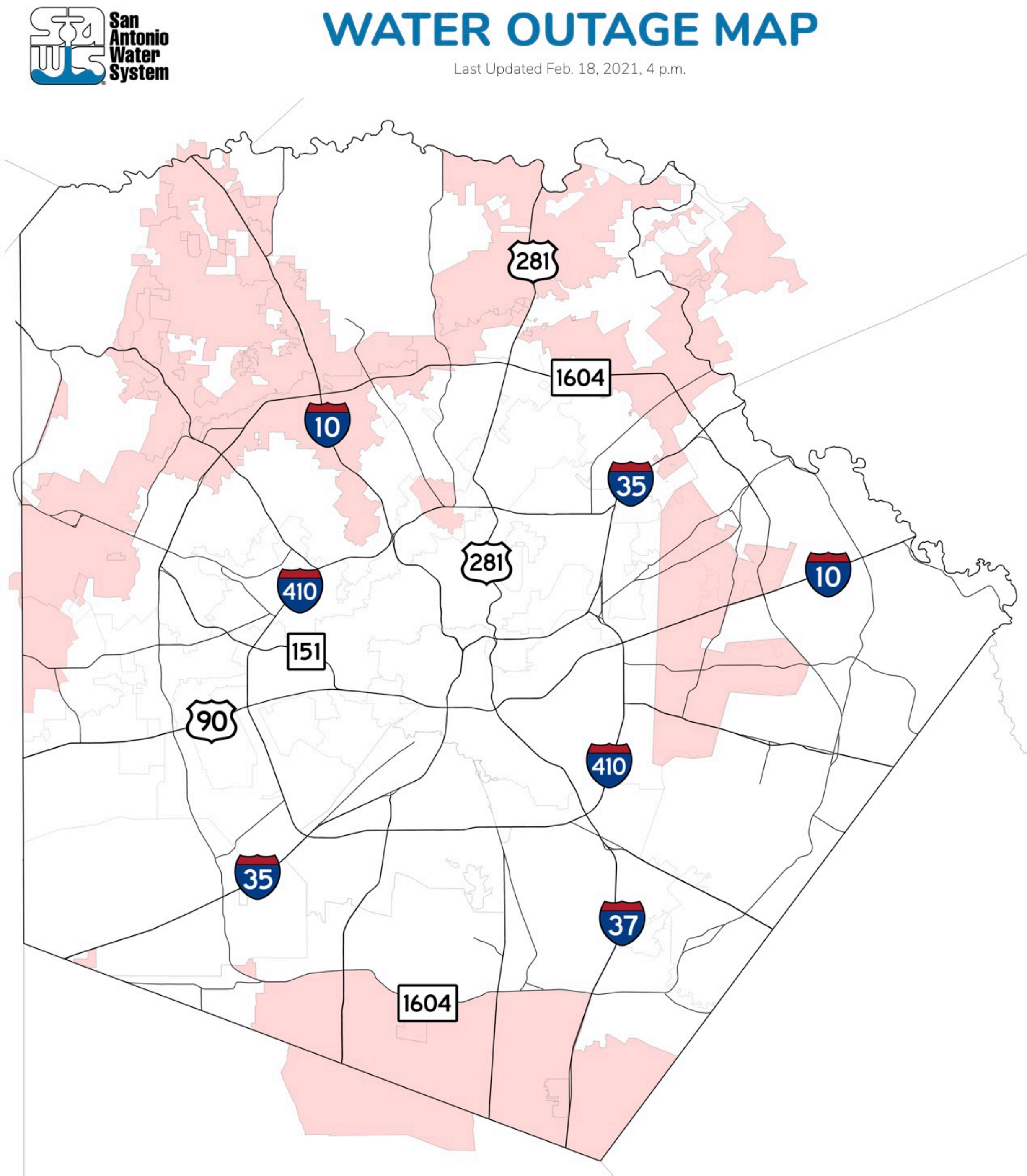
    trained in the FEMA individual assistance application process so that they could provide this service
  - Emergency resource center opened
  - Residents began to receive disaster recovery assistance
- **Friday, February 26th –**
  - Bottled water distribution operation ended

Exhibit B - SAWS Water Outage Maps

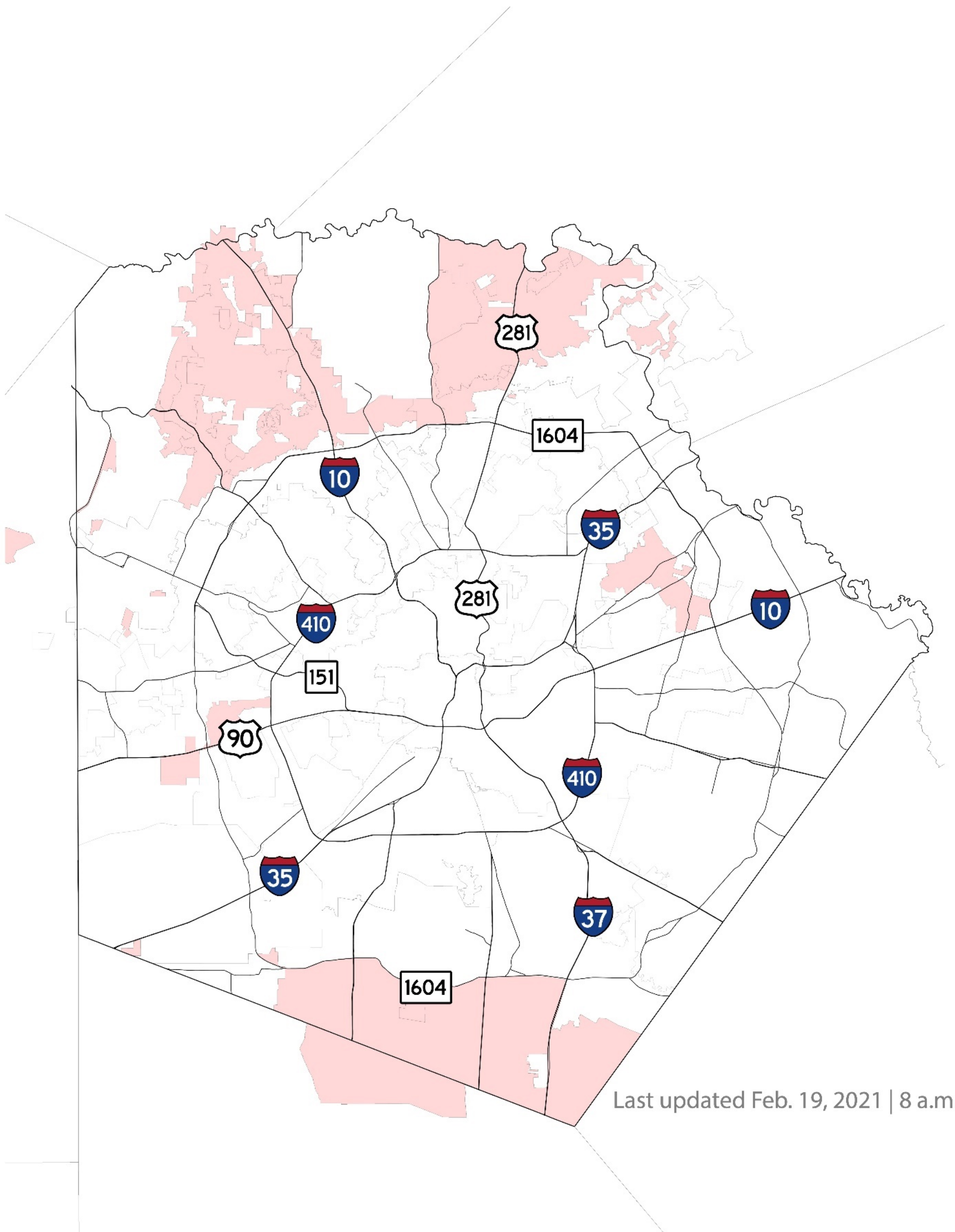
SAWS Water Outage Map – February 18, 2021 8:00 A.M.



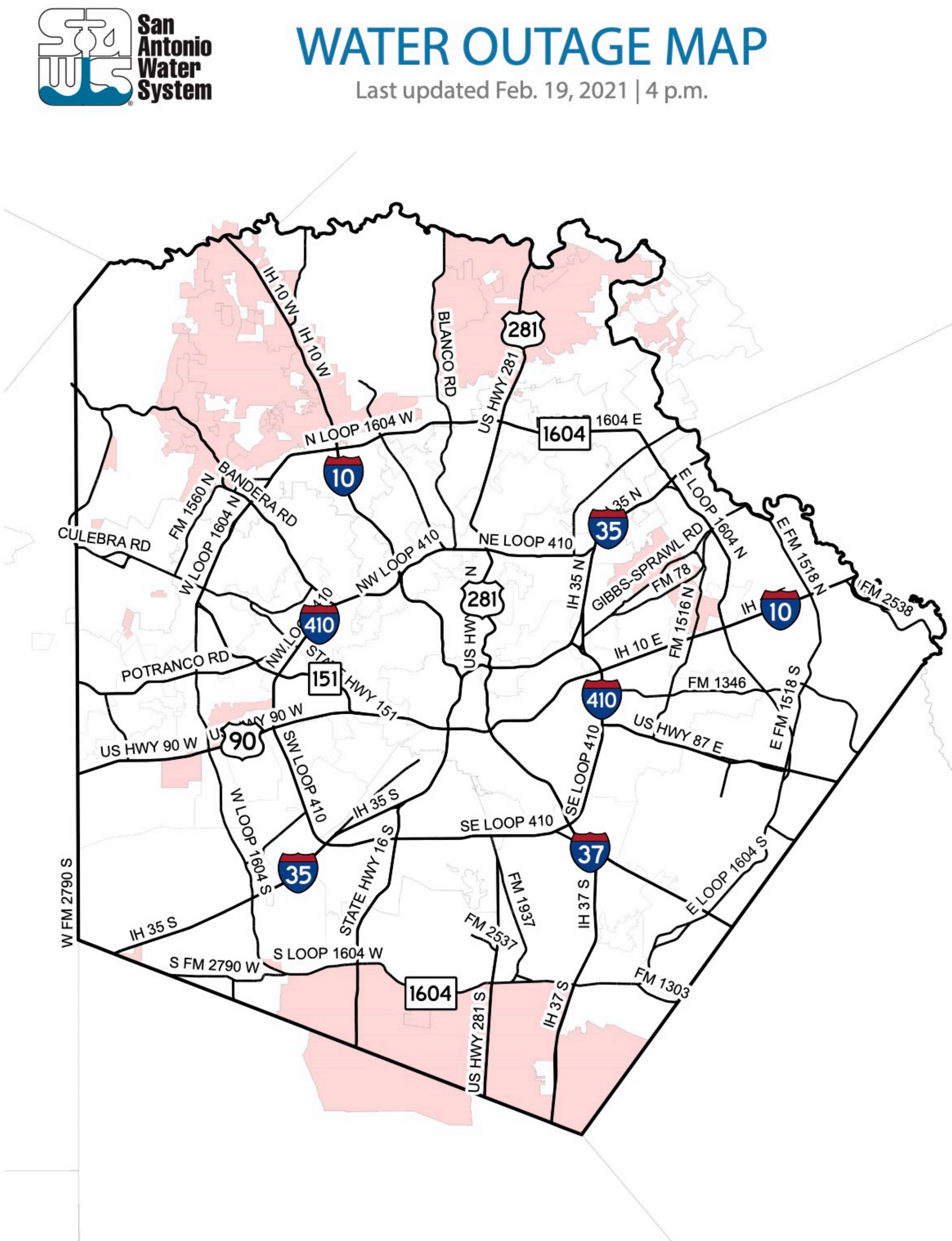
SAWS Water Outage Map – February 18, 2021 4:00 P.M.



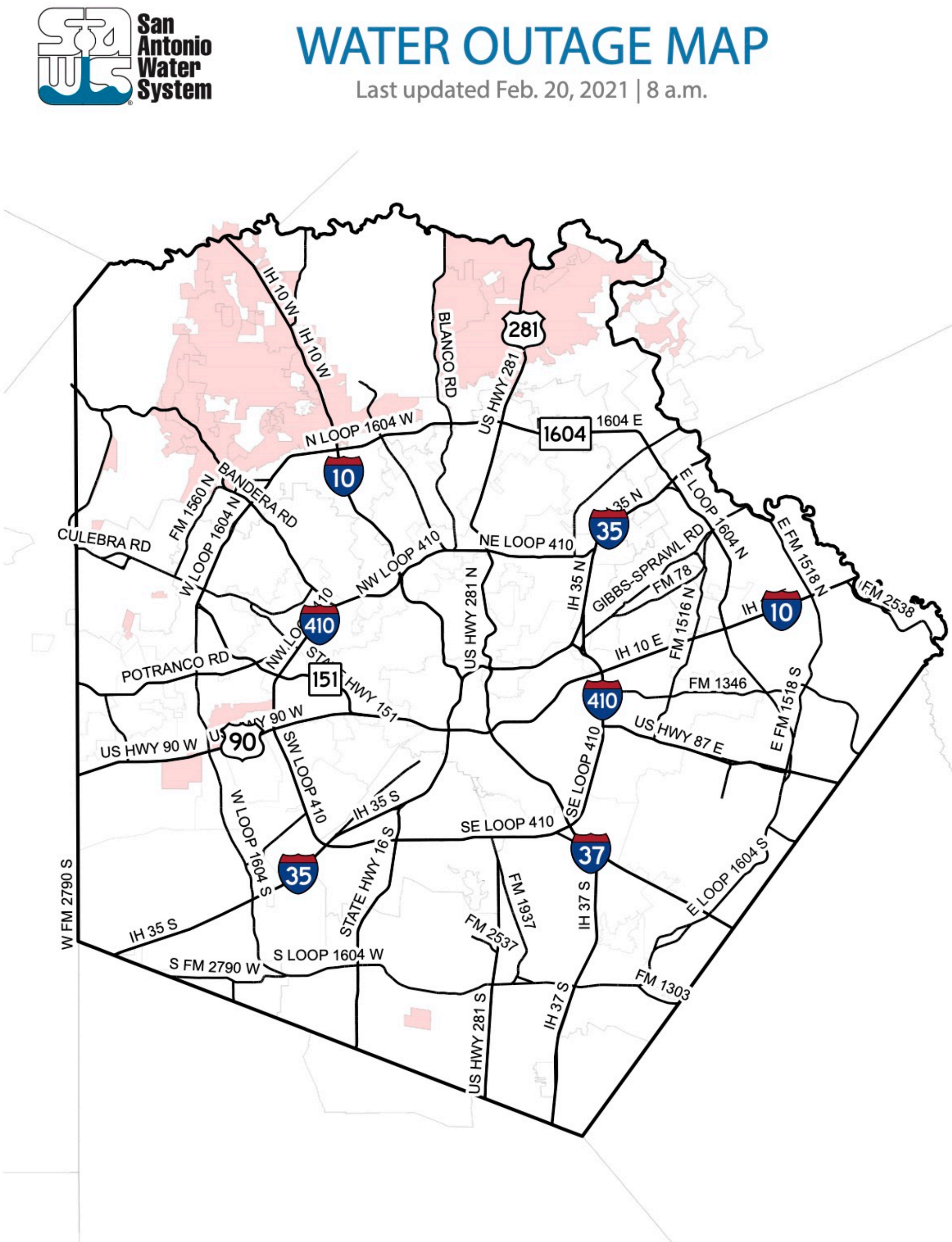
SAWS Water Outage Map – February 19, 2021 8:00 A.M.



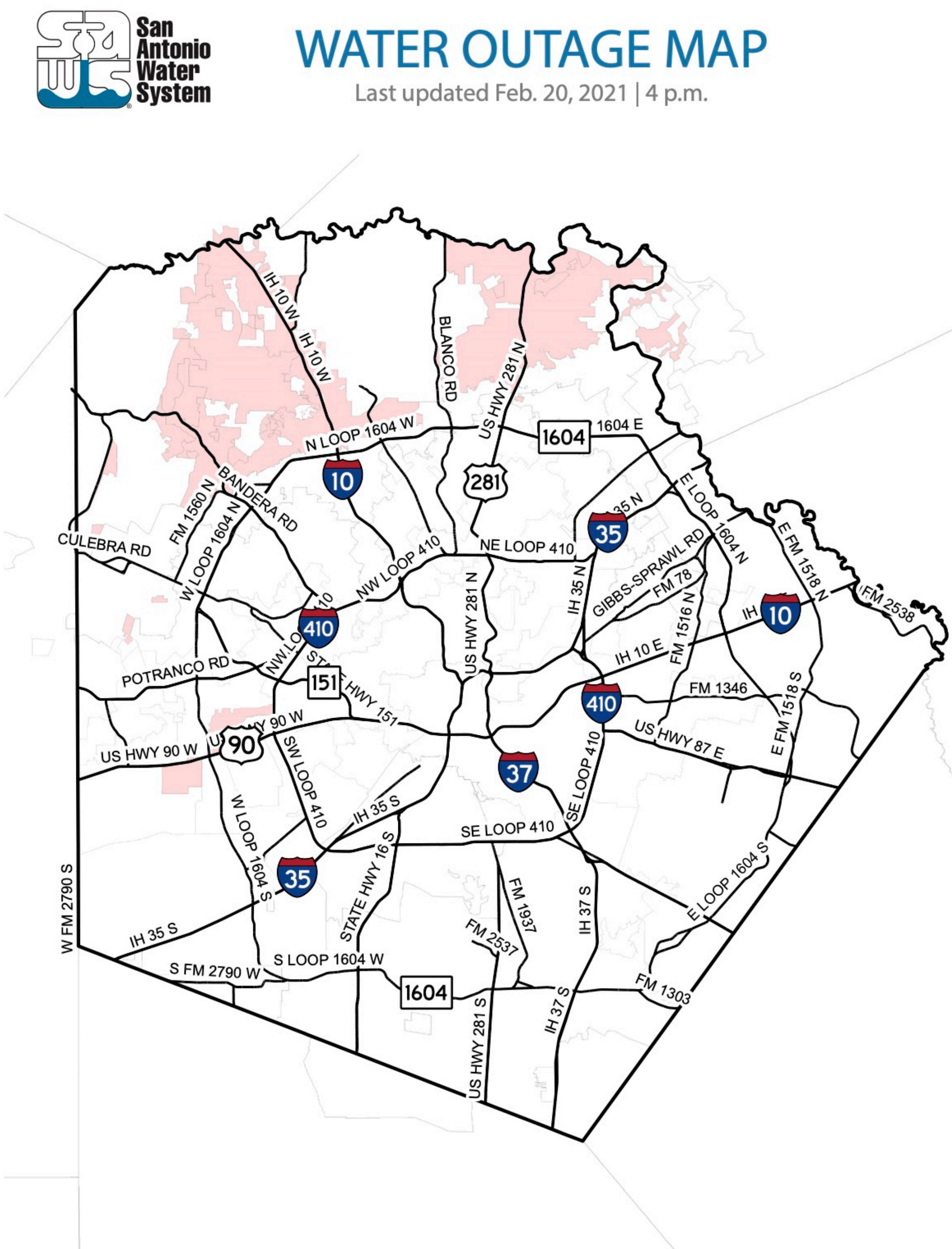
SAWS Water Outage Map – February 19, 2021 4:00 P.M.



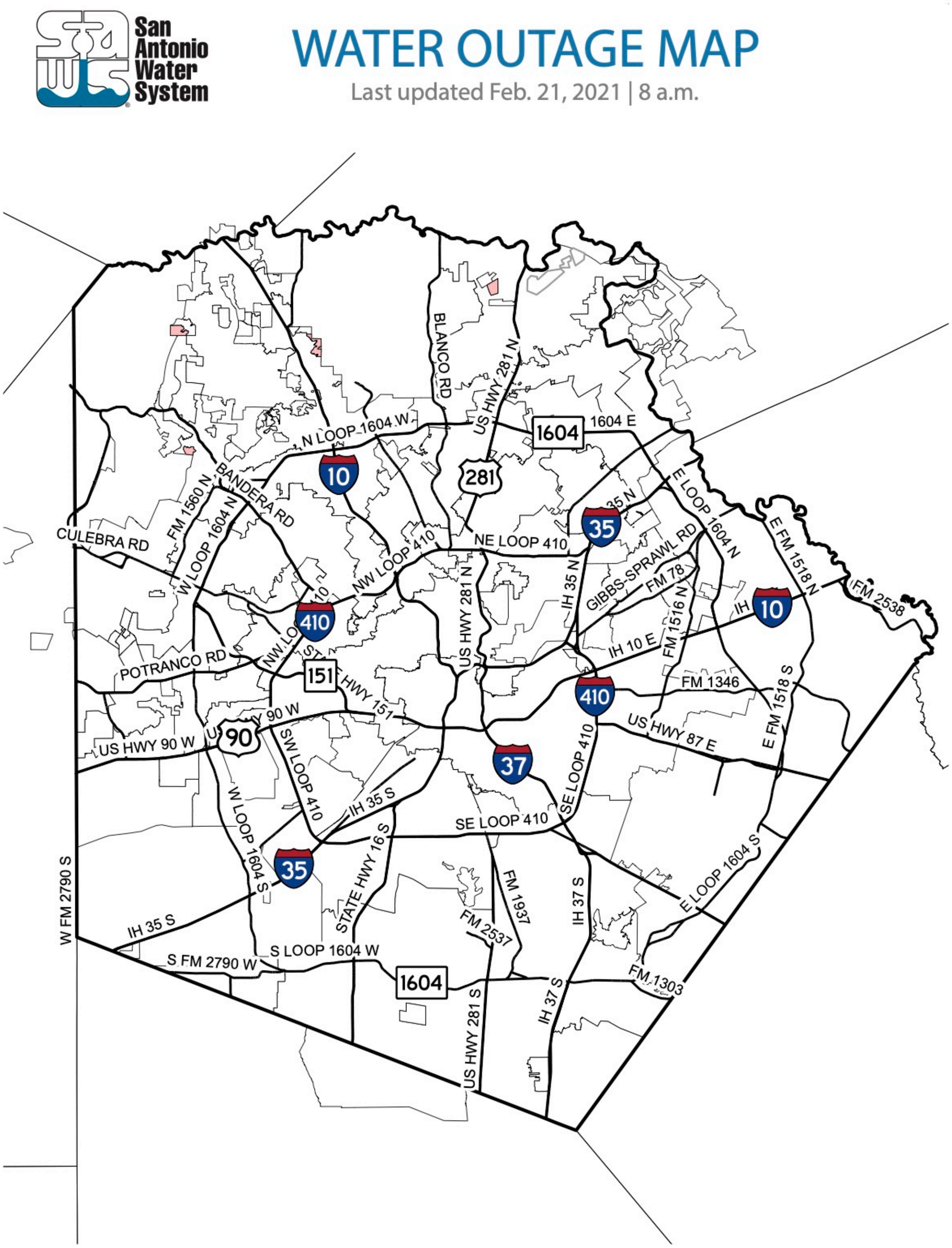
SAWS Water Outage Map – February 20, 2021 8:00 A.M.



SAWS Water Outage Map – February 20, 2021 4:00 P.M.



SAWS Water Outage Map – February 21, 2021 8:00 A.M.



Appendix 2

Public Utility Commission of Texas

1701 N. Congress, P.O. Box 13326, Austin, TX 78711-3326 Fax 512-936-7003

News Release
October 21, 2021

Contact: Andrew Barlow
Media@PUC.Texas.Gov

PUC Adopts Rules for Weatherization of Power Infrastructure

First phase of two-part process requires CEO certification of compliance

Austin, TX – The Public Utility Commission of Texas today adopted a new rule related to the weather emergency preparedness of power generators and utilities in Texas. The first of two phases in the process, the rule compels generator and utility compliance with winter weather readiness recommendations. Affected companies must also attest to the repair of any known, acute issues that arose from the February 2021 storm event before the end of the year.

"This rule is a vital step in our ongoing efforts to harden the grid for future weather challenges," said PUC Chairman Peter Lake. "The Legislature made it clear that these companies are accountable for the readiness of their facilities and these rules give them a clear path and incentive for compliance."

Based on requirements from Senate Bill 3, the new PUC **rule** translates established industry best practices into specific actions backed with inspections and the power of significantly increased financial penalties. The generator readiness standards in question were drawn from the 2012 **Quanta Report** (more formally the "Quanta Technology Report on Extreme Weather Preparedness Best Practices"). Requirements for transmission service providers arise from the "**Report on Outages and Curtailments During the Southwest Cold Weather Event on February 1-5, 2011**" jointly prepared in 2011 by the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation.

"The electric industry must be prepared to provide reliable electric service throughout this upcoming winter weather season," continued Lake. "Today's milestone gives generators and utilities the guidance they need to provide the reliable service that Texans deserve."

The second phase of the weatherization rulemaking process targets the creation of a more comprehensive, year-round set of weather emergency preparedness reliability standards that will be informed by ERCOT's ongoing weather study.

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Appendix 3

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS.

Subchapter C. INFRASTRUCTURE AND RELIABILITY.

§25.55. Weather Emergency Preparedness.

(a) **Application.** This section applies to the Electric Reliability Council of Texas, Inc. (ERCOT) and to generation entities and transmission service providers (TSPs) in the ERCOT power region. A generation resource with an ERCOT-approved notice of suspension of operations for the 2021-2022 winter weather season is not required to be in compliance under this section until it is returned to service.

(b) **Definitions.** In this section, the following definitions apply unless the context indicates otherwise.

(1) **Cold weather critical component –** Any component that is susceptible to freezing or icing, the occurrence of which is likely to significantly hinder the ability of a resource or transmission system to function as intended and, for a generation entity, to lead to a trip, derate, or failure to start of a resource. For a TSP, cold weather critical component is limited to any transmission-voltage component within the fence surrounding a TSP's high-voltage switching station or substation.

(2) **Energy storage resource –** An energy storage system registered with ERCOT for the purpose of providing energy or ancillary services to the ERCOT grid and associated facilities controlled by the generation entity that are behind the system's point of interconnection, necessary for the operation of the system, and not part of a manufacturing process that is separate from the generation of electricity.

(3) **Generation entity** - An ERCOT-registered resource entity acting on behalf of an ERCOT-registered generation resource or energy storage resource.

(4) **Generation resource –** A generator capable of providing energy or ancillary services to the ERCOT grid and that is registered with ERCOT as a generation resource, as well as associated facilities controlled by the generation entity that are behind the generator's point of interconnection, necessary for the operation of the generator, and not part of a manufacturing process that is separate from the generation of electricity.

(5) **Inspection** –Activities that ERCOT engages in to determine whether a generation entity is in compliance with all or parts of subsection (c)(1) of this section or whether a TSP is in compliance with all or parts of subsection (f)(1) of this section. An inspection may include site visits; assessments of procedures; interviews; and review of information provided by a generation entity or TSP in response to a request by ERCOT, including review of evaluations conducted by the generation entity or TSP or its contractor.

(6) **Resource** - A generation resource or energy storage resource.

(7) **Weather emergency** – A situation resulting from weather conditions that produces significant risk for a TSP that firm load must be shed or a situation for which ERCOT provides advance notice to market participants involving weather-related risks to the ERCOT power region.

(8) **Weather emergency preparation measures –** Measures that a generation entity or TSP takes to support the function of a facility during a weather emergency.

(c) **Weather emergency preparedness reliability standards for a generation entity.**

(1) By December 1, 2021, a generation entity must complete the following winter weather emergency preparation measures for each resource under its control.

(A) Use best efforts to implement weather emergency preparation measures intended to ensure the sustained operation of all cold weather critical components during winter weather conditions, including weatherization, onsite fuel security, staffing plans, operational readiness, and structural preparations; secure sufficient chemicals, auxiliary fuels, and other materials; and personnel required to operate the resource;

(B) Install adequate wind breaks for resources susceptible to outages or derates caused by wind; enclose sensors for cold weather critical components; inspect thermal insulation for damage or degradation and repair damaged or degraded insulation; confirm the operability of instrument air moisture prevention systems; conduct maintenance of freeze protection components for all applicable equipment, including fuel delivery systems controlled by the generation entity, the failure of which could cause an outage or derate, and establish a schedule for testing of such freeze protection components on a monthly basis from November through March; and install monitoring systems for cold weather critical components, including circuitry providing freeze protection or preventing instrument air moisture;

(C) Use best efforts to address cold weather critical component failures that occurred because of winter weather conditions in the period between November 30, 2020, and March 1, 2021;

(D) Provide training on winter weather preparations and operations to relevant operational personnel; and

(E) Determine minimum design temperature or minimum experienced operating temperature, and other operating limitations based on temperature, precipitation, humidity, wind speed, and wind direction.

(2) By December 1, 2021, a generation entity must submit to the commission and ERCOT, on a form prescribed by ERCOT and developed in consultation with commission staff, a winter weather readiness report that:

(A) Describes all activities engaged in by the generation entity to complete the requirements of paragraph (1) of this subsection, including any assertions of good cause for noncompliance submitted under paragraph (6) of this subsection; and

(B) Includes a notarized attestation sworn to by the generation entity's highest-ranking representative, official, or officer with binding authority over the generation entity attesting to the completion of all activities described in paragraph (1) of this subsection, subject to any notice of or request for good cause exception submitted under paragraph (6) of this subsection, and to the accuracy and veracity of the information described in subparagraph (A) of this paragraph.

(3) No later than December 10, 2021, ERCOT must file with the commission comprehensive checklist forms based on the requirements of paragraph (1) of this subsection that include checking systems and subsystems containing cold weather critical components. ERCOT must use a generation entity's winter weather readiness report submitted under paragraph (2) of this subsection to adapt the checklist to the inspections of the generation entity's resources.

(4) No later than December 10, 2021, ERCOT must file with the commission a compliance report that addresses whether each generation entity has submitted the winter weather readiness report required by paragraph (2) of this subsection for each resource under the generation entity's control and whether the generation entity submitted an assertion of good cause for noncompliance under paragraph (6) of this subsection.

(5) A generation entity that timely submits to ERCOT the winter weather readiness report required by paragraph (2) of this subsection is exempt, for the 2021 calendar year, from the requirement in Section 3.21(3) of the ERCOT Protocols that requires a generation entity to submit the Declaration of Completion of Generation Resource Winter Weatherization Preparations no earlier than November 1 and no later than December 1 of each year.

(6) Good cause exception. A generation entity may submit by December 1, 2021 a notice to the commission asserting good cause for noncompliance with specific requirements listed in paragraph (1) of this subsection. The notice must be submitted as part of the generation entity's winter readiness report under paragraph (2) of this subsection.

(A) A generation entity's notice must include:

(i) A succinct explanation and supporting documentation of the generation entity's inability to comply with a specific requirement of paragraph (1) of this subsection;

(ii) A succinct description and supporting documentation of the generation entity's efforts that have been made to comply with the paragraph (1) of this subsection;

(iii) A plan, with supporting documentation, to comply with each specific requirement of paragraph (1) of this subsection for which good cause is being asserted, unless good cause exists not to comply with the requirement on a permanent basis. A plan under this subparagraph must include a proposed compliance deadline for each requirement of paragraph (1) of this subsection for which the good cause for noncompliance is being asserted and proposed filing deadlines for the generation entity to provide the commission with updates on its compliance status.

(B) Commission staff will work with ERCOT to expeditiously review notices asserting good cause for noncompliance. Commission staff may notify a generation entity that it disagrees with the generation entity's assertion of good cause and will file the notification in the project in which the winter weather readiness reports are filed. In addition, ERCOT may evaluate the generation entity's assertion of good cause as part of an inspection of the generation entity's resources.

(C) To preserve a good cause exception, a generation entity must submit to the commission a request for approval of a good cause exception within seven days of receipt of commission staff's notice of disagreement with the generation entity's assertion.

(D) The commission may order a generation entity to submit a request for approval of good cause exception.

(E) A request for approval of good cause exception must contain the following:

(i) A detailed explanation and supporting documentation of the inability of the generation entity to comply with a specific requirement of paragraph (1) of this subsection;

(ii) A detailed description and supporting documentation of the efforts that have been made to comply with paragraph (1) of this subsection;

(iii) A plan, with supporting documentation, to comply with each specific requirement of paragraph (1) of this subsection for which the good cause exception is being requested, unless the generation entity is seeking a permanent exception to the requirement. A plan under this subparagraph must include a proposed compliance deadline for each requirement of paragraph (1) of this subsection for which the good cause exception is being requested and proposed filing deadlines for the generation entity to provide the commission with updates on its compliance status.

(iv) Proof that notice of the request has been provided to ERCOT; and

(v) A notarized attestation sworn to by the generation entity's highest-ranking representative, official, or officer with binding authority over the generation entity attesting to the accuracy and veracity of the information in the request.

(F) ERCOT is a required party in a proceeding initiated under subparagraph (E) of this paragraph. ERCOT must make a recommendation to the commission on the request by the deadline set forth by the presiding officer in the proceeding.

(d) ERCOT inspection of generation resources.

(1) ERCOT-conducted inspections. ERCOT must conduct inspections of resources for the 2021–2022 winter weather season and must prioritize its inspection schedule based on risk level. ERCOT may prioritize inspections based on factors such as whether a generation resource is critical for electric grid reliability; has experienced a forced outage, forced derate, or failure to start related to weather emergency conditions; or has other vulnerabilities related to weather emergency conditions. ERCOT must determine, in consultation with commission staff, the number, extent, and content of inspections and may conduct inspections using both employees and contractors.

(A) ERCOT must provide each generation entity at least 48 hours' notice of an inspection unless otherwise agreed by the generation entity and ERCOT. Upon provision of the required notice, a generation entity must grant access to its facility to ERCOT and commission personnel, including an employee of a contractor designated by ERCOT or the commission to conduct, oversee, or observe the inspection.

(B) During the inspection, a generation entity must provide ERCOT and commission personnel access to any part of the facility upon request and must make the generation entity's staff available to answer questions. A generation entity may escort ERCOT and commission personnel at all times during an inspection. During the inspection, ERCOT or commission personnel may take photographs and video recordings of any part of the facility and may conduct interviews of facility personnel designated by the generation entity.

(2) ERCOT inspection report.

(A) ERCOT must provide a report on its inspection of a resource to the generation entity. The inspection report must address whether the generation entity has complied with the requirements in subsection (c)(1) of this section.

(B) If the generation entity has not complied with a requirement in subsection (c)(1) of this section, ERCOT must provide the generation entity a reasonable period to cure the identified deficiencies.

(i) The cure period determined by ERCOT must consider what weather emergency preparation measures the generation entity may be reasonably expected to have taken before ERCOT's inspection, the reliability risk of the resource's noncompliance, and the complexity of the measures needed to cure the deficiency.

(ii) The generation entity may request ERCOT determine a different amount of time to remedy the deficiencies. The request must be accompanied by documentation that supports the request for a different amount of time.

(iii) ERCOT, in consultation with commission staff, will determine the final cure period after considering a request for a different amount of time.

(C) ERCOT must report to commission staff any generation entity that does not remedy the deficiencies identified under subparagraph (A) of this paragraph within the cure period determined by ERCOT under subparagraph (B)(iii) of this paragraph.

(D) A generation entity reported by ERCOT to commission staff under subparagraph (C) of this paragraph will be subject to enforcement investigation under §22.246 (relating to Administrative Penalties) of this title.

(e) Weather-related failures by a generation entity to provide service. A generation entity with a resource that experiences repeated or major weather-related forced interruptions of service, such as forced outages, derates, or maintenance-related outages must contract with a qualified professional engineer to assess its weather emergency preparation measures, plans, procedures, and operations. The qualified professional engineer must not be an employee of the generation entity or its affiliate and must not have participated in previous assessments for the resource for at least five years, unless the generation entity can document that no other qualified professional engineers are reasonably available for engagement. The generation entity must submit the qualified professional engineer's assessment to the commission and ERCOT. ERCOT must adopt rules that specify the circumstances for which this requirement applies and specify the scope and contents of the assessment. A generation entity to which this subsection applies may be subject to additional inspections by ERCOT. ERCOT must refer to commission staff for investigation any generation entity that violates this rule.

(f) Weather emergency preparedness reliability standards for a TSP.

(1) By December 1, 2021, a TSP must complete the following winter weather preparations for its transmission system and facilities.

(A) Use best efforts to implement weather emergency preparation measures intended to ensure the sustained operation of all cold weather critical components during winter weather conditions, including weatherization, staffing plans, operational readiness, and structural preparations; secure sufficient chemicals, auxiliary fuels, and other materials; and personnel required to operate the transmission system and facilities;

(B) Confirm the ability of all systems and subsystems containing cold weather critical components required to ensure operation of each of the TSP's substations within the design and operating limitations addressed in subparagraph (G) of this paragraph;

(C) Use best efforts to address cold weather critical component failures that occurred because of winter weather conditions in the period between November 30, 2020 and March 1, 2021;

(D) Provide training on winter weather preparations and operations to relevant operational personnel;

(E) Confirm that the sulfur hexafluoride gas in breakers and metering and other electrical equipment is at the correct pressure and temperature to operate safely during winter weather emergencies, and perform annual maintenance that tests sulfur hexafluoride breaker heaters and supporting circuitry to assure that they are functional;

(F) Confirm the operability of power transformers and auto transformers in winter weather emergencies by:

(i) Checking heaters in the control cabinets;

(ii) Verifying that main tank oil levels are appropriate for actual oil temperature;

(iii) Checking bushing oil levels; and

(iv) Checking the nitrogen pressure, if necessary.

(G) Determine minimum design temperature or minimum experienced operating temperature, and other operating limitations based on temperature, precipitation, humidity, wind speed, and wind direction for facilities containing cold weather critical components.

(2) By December 1, 2021, a TSP must submit to the commission and ERCOT, on a form prescribed by ERCOT and developed in consultation with commission staff, a winter weather readiness report that:

(A) Describes all activities engaged in by the TSP to complete the requirements of paragraph (1) of this subsection, including any assertions of good cause for noncompliance submitted under paragraph (4) of this subsection; and

(B) Includes a notarized attestation sworn to by the TSP's highest-ranking representative, official, or officer with binding authority over the TSP, attesting to the completion of all activities described in paragraph (1) of this subsection, subject to any notice of or request for good cause exception submitted under paragraph (4) of this subsection, and to the accuracy and veracity of the information described in subparagraph (A) of this paragraph.

(3) No later than December 10, 2021, ERCOT must file with the commission a compliance report that addresses whether each TSP has submitted the winter weather readiness report required by paragraph (2) of this subsection for its transmission system and facilities and whether the TSP submitted an assertion of good cause for noncompliance under paragraph (4) of this subsection.

(4) Good cause exception. A TSP may submit to the commission by December 1, 2021 a notice asserting good cause for noncompliance with specific requirements listed in paragraph (1) of this subsection. The notice must be submitted as part of the TSP's winter weather readiness report under paragraph (2) of this subsection.

(A) A TSP's notice must include:

(i) A succinct explanation and supporting documentation of the TSP's inability to comply with a specific requirement of paragraph (1) of this subsection;

(ii) A succinct description and supporting documentation of the efforts that have been made to comply with the requirement; and

(iii) A plan, with supporting documentation, to comply with each specific requirement of paragraph (1) of this subsection for which good cause is being asserted, unless good cause exists not to comply with the requirement on a permanent basis. A plan under this subparagraph must include a proposed compliance deadline for each requirement of paragraph (1) of this subsection for which good cause for noncompliance is being asserted and proposed filing deadlines for the TSP to provide the commission with updates on the TSP's compliance status.

(B) Commission staff will work with ERCOT to expeditiously review notices asserting good cause for noncompliance. Commission staff may notify a TSP that it disagrees with the TSP's assertion of good cause and will file the notification in the project in which the winter weather readiness reports are filed. In addition, ERCOT may evaluate the TSP's assertion of good cause as part of an inspection of the transmission facility.

(C) To preserve a good cause exception, a TSP must submit to the commission a request for approval of a good cause exception within seven days of receipt of commission staff's notice of staff's disagreement with the TSP's assertion.

(D) The commission may order a TSP to submit a request for approval of good cause exception.

(E) A request for approval of good cause exception must contain the following:

(i) A detailed explanation and supporting documentation of the inability of the TSP to comply with the specific requirement of paragraph (1) of this subsection;

(ii) A detailed description and supporting documentation of the efforts that have been made to comply with paragraph (1) of this subsection;

(iii) A plan, with supporting documentation, to comply with each specific requirement of paragraph (1) of this subsection for which the good cause exception is being requested, unless the TSP is seeking a permanent exception to the requirement. A plan under this subparagraph must include a proposed compliance deadline for each requirement of paragraph (1) of this subsection for which the good cause exception is being requested and proposed filing deadlines for the TSP to provide the commission with updates on its compliance status.

(iv) Proof that notice of the request has been provided to ERCOT; and

(v) A notarized attestation sworn to by the TSP's highest-ranking representative, official, or officer with binding authority over the TSP attesting to the accuracy and veracity of the information in the request.

(F) ERCOT is a required party to the proceeding under subparagraph (E) of this paragraph. ERCOT must make a recommendation to the commission on the request by the deadline set forth by the presiding officer in the proceeding.

(g) **ERCOT inspections of transmission systems and facilities.**

(1) ERCOT-conducted inspections. ERCOT must conduct inspections of transmission facilities within the fence surrounding a TSP's high-voltage switching station or substation for the 2021–2022 winter weather season and must prioritize its inspection schedule based on risk level. ERCOT may prioritize inspections based on factors such as whether atransmission facility is critical for electric grid reliability; has experienced a forced outage or other failure related to weather emergency conditions; or has other vulnerabilities related to weather emergency conditions. ERCOT must determine, in consultation with commission staff, the number, extent, and content of inspections and may conduct inspections using both employees and contractors.

(A) ERCOT must provide each TSP at least 48 hours' notice of an inspection unless otherwise agreed by the TSP and ERCOT. Upon provision of the required notice, a TSP must grant access to its facility to ERCOT and commission personnel, including an employee of a contractor designated by ERCOT or the commission to conduct, oversee, or observe the inspection.

(B) During the inspection, a TSP must provide ERCOT and commission personnel access to any part of the facility upon request and must make the TSP's staff available to answer questions. A TSP may escort ERCOT and commission personnel at all times during an inspection. During the inspection, ERCOT and commission personnel may take photographs and video recordings of any part of the facility and may conduct interviews of facility personnel designated by the TSP.

(2) ERCOT inspection report.

(A) ERCOT must provide a report on its inspection of a transmission system or facility to the TSP. The inspection report must address whether the TSP has complied with the requirements in subsection (f)(1) of this section.

(B) If the TSP has not complied with a requirement in subsection (f)(1) of this section, ERCOT must provide the TSP a reasonable period to cure the identified deficiencies.

(i) The cure period determined by ERCOT must consider what weather emergency preparation measures the TSP may be reasonably expected to have taken before ERCOT's inspection, the reliability risk of the TSP's noncompliance, and the complexity of the measures needed to cure the deficiency.

(ii) The TSP may request ERCOT determine a different amount of time to remedy the deficiencies. The request must be accompanied by documentation that supports the request for a different amount of time.

(iii) ERCOT, in consultation with commission staff, will determine the final cure period after considering a request for a different amount of time.

(C) ERCOT must report to commission staff any TSP that does not remedy the deficiencies identified under subparagraph (A) of this paragraph within the cure period determined by ERCOT under subparagraph (B)(iii) of this paragraph.

(D) A TSP reported by ERCOT to commission staff under subparagraph (C) of this paragraph will be subject to enforcement investigation under §22.246 (relating to Administrative Penalties) of this title.

(h) **Weather-related failures by a TSP to provide service**. A TSP with a transmission system or facility that experiences repeated or major weather-related forced interruptions of service must contract with a qualified professional engineer to assess its weather emergency preparation measures, plans, procedures, and operations. The qualified professional engineer must not be an employee of the TSP or its affiliate and must not have participated in previous assessments for this system or facility for at least five years, unless the TSP can document that no other qualified professional engineers are reasonably available for engagement. The TSP must submit the qualified professional engineer's assessment to the commission and ERCOT. ERCOT must adopt rules that specify the circumstances for which this requirement applies and specify the scope and contents of the assessment. A TSP to which this subsection applies may be subject to additional inspections by ERCOT. ERCOT must refer to commission staff for investigation any TSP that violates this rule.

Appendix 4

Filing Receipt

Received - 2021-10-19 08:17:01 AM
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OPEN MEETING COVER SHEET

MEMORANDUM AND PROPOSAL FOR ADOPTION

MEETING DATE:	October 21, 2021
DATE DELIVERED:	October 18, 2021
AGENDA ITEM NO.:	1
CAPTION:	Project No. 51840 – Rulemaking to Etablish Electric Weatherization Standards
DESCRIPTION:	Memo and Proposal for Adoption

Public Utility Commission of Texas

Memorandum

TO:	Chairman Peter Lake Commissioner Will McAdams Commissioner Lori Cobos Commissioner Jimmy Glotfelty
FROM:	Barksdale English, Director, Division of Compliance and Enforcement
DATE:	October 18, 2021
RE:	October 21, 2021 Open Meeting – Agenda Item No. 1 Project No. 51840, *Rulemaking to Establish Electric Weatherization Standards*

Please find attached to this memorandum Commission Staff's proposal for adoption (PFA) in the above-referenced project for consideration at the October 21, 2021 Open Meeting.

This PFA establishes new §25.55, relating to weather emergency preparedness. Specifically, the rule requires generators to implement winter weather readiness recommendations identified in the 2012 Quanta Technology Report on Extreme Weather Preparedness Best Practices (2012 Quanta Report) and to fix any known, acute issues that arose from winter weather conditions during the 2020–2021 winter weather season. Similarly, this rule requires transmission service providers to implement key recommendations contained in the 2011 Report on Outages and Curtailments During the Southwest Cold Weather Event on February 1-5, 2011, jointly prepared by the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, and to fix any known, acute issues that arose during the 2020-2021 winter weather season. Further, this rule requires a notarized attestation from the highest-ranking representative, official, or officer with binding authority over each of the above entities attesting to the completion of all required actions.

This project represents the first of two phases in the commission's development of robust weather emergency preparedness reliability standards and will help ensure that the electric industry is prepared to provide continuous reliable electric service throughout this upcoming winter weather season. The commission will develop phase two of its weather emergency preparedness reliability standards in a future project. The phase-two weather emergency preparedness reliability standards will consist of a more comprehensive, year-round set of weather emergency preparedness reliability standards that will be informed by a robust weather study that is currently being conducted by ERCOT in consultation with the Office of the Texas State Climatologist.

PROJECT NO. 51840

RULEMAKING TO ESTABLISH ELECTRIC WEATHERIZATION STANDARDS	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

(STAFF RECOMMENDATION)

PROPOSAL FOR ADOPTION FOR NEW 16 TAC § 25.55

The Public Utility Commission of Texas (commission) adopts new 16 Texas Administrative Code (TAC) §25.55, relating to weather emergency preparedness, to implement weather emergency preparation measures for generation entities and transmission service providers (TSPs) in the Electric Reliability Council of Texas (ERCOT) power region, as required by Senate Bill 3 (SB 3), 87th Legislature Regular Session (Regular Session).

New §25.55 represents the first of two phases in the commission's development of robust weather emergency preparedness reliability standards and will help ensure that the electric industry is prepared to provide continuous reliable electric service throughout this upcoming winter weather season. Specifically, the rule requires generators to implement winter weather readiness recommendations identified in the 2012 Quanta Technology Report on Extreme Weather Preparedness Best Practices (2012 Quanta Report) and to fix any known, acute issues that arose from winter weather conditions during the 2020–2021 winter weather season. Similarly, this rule requires TSPs to implement key recommendations contained in the 2011 Report on Outages and Curtailments During the Southwest Cold Weather Event on February 1-5, 2011, jointly prepared by the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation (2011 FERC/NERC Report), and to fix any known, acute issues that arose during the 2020-2021 winter weather season. Further, this rule requires a notarized attestation from the highest-ranking representative, official, or officer with binding authority over each of the above entities attesting to the completion of all required actions.

The commission will develop phase two of its weather emergency preparedness reliability standards in a future project. The phase-two weather emergency preparedness reliability standards will consist of a more comprehensive, year-round set of weather emergency preparedness reliability standards that will be informed by a robust weather study that is currently being conducted by ERCOT in consultation with the Office of the Texas State Climatologist.

The commission received comments on the proposed rule from AARP; Advanced Power Alliance and American Clean Power Association (APA and ACP); AEP Texas Inc. and Electric Transmission Texas LLC (AEP Companies); Calpine Corporation (Calpine); Capital Power Corporation (Capital Power); CenterPoint Energy Houston Electric, LLC (CenterPoint); City of Houston; Conservative Texans for Energy Innovation; Enbridge, Inc. (Enbridge); Enel North America (Enel); Exelon Generation Company, LLC (Exelon); Lower Colorado River Authority (LCRA); Lower Colorado River Authority Transmission Services Corporation (LCRA TSC); NextEra Energy Resources, LLC (NextEra); Oncor Electric Delivery Company, LLC (Oncor); Office of Public Utility Counsel (OPUC); Public Citizen; RWE Renewables America, LLC (RWE); Savion, LLC (Savion); Sharyland Utilities, LLC (Sharyland); Solar Energy Industries Association (SEIA); Steering Committee of Cities Served by Oncor (Oncor Cities); Texas Competitive Power Advocates (TCPA); Texas Advanced Energy Business Alliance (TAEBA); Texas Electric Cooperatives, Inc. (TEC); Texas Public Power Association (TPPA); Texas Solar

Power Association (TSPA); Texas-New Mexico Power Company (TNMP); Texas Industrial Energy Consumers (TIEC); and Vistra Corporation (Vistra).

General Comments

Two-Phase Approach

OPUC, TPPA, and Conservative Texans for Energy Innovation supported the two-phase approach. OPUC stated that the two-phase approach will allow standards to be in place for the upcoming winter while still allowing time to develop more robust standards in the coming months. Oncor Cities stated that the rule should include summer preparedness. Oncor Cities also requested an explanation of the scope of the ERCOT weather study and how the ERCOT weather study will be used as an input to the weatherization standard. Oncor Cities requested an explanation of the scope of the second phase of this legislative implementation. Oncor Cities suggested that generation entities and TSPs will be able to plan more effectively if these concepts are more fully developed now.

Commission Response

This rule is focused on establishing weather emergency preparedness reliability standards for the 2021-2022 winter weather season. The commission will develop phase two weather emergency preparedness reliability standards in a future project that will consist of a more comprehensive, year-round set of weather emergency preparedness reliability standards that will be informed by a robust weather study that is currently being conducted by ERCOT in consultation with the Office of the Texas State Climatologist. The commission disagrees

with Oncor Cities that including summer preparedness standards in phase one of this project is required to comply with SB 3.

<u>*2012 Quanta Report and 2011 FERC/NERC Report*</u>

Oncor Cities stated that the rule should reference both the specific winter readiness actions identified in the 2012 Quanta Report and the key recommendations contained in the 2011 FERC/NERC Report the commission requires entities to implement through this rule. Oncor and Vistra supported the commission's goal of implementing key recommendations from the 2011 FERC/NERC Report for the 2021-2022 winter weather season as the first phase of this rulemaking.

Commission Response

The commission declines to make changes in response to the comments of Oncor Cities. The rule requires generators to implement certain winter weather readiness recommendations identified in the 2012 Quanta Report and to fix any known, acute issues that arose from winter weather conditions during the 2020–2021 winter weather season. The commission also requires TSPs to implement key recommendations contained in the 2011 FERC/NERC Report. Adding general references to those reports to the language of the rule would introduce ambiguity without improving the rule's clarity.

RWE stated that the best practices from the 2012 Quanta Report may be outdated because the generation resource mix in the ERCOT power region includes higher percentages of wind, solar, and energy storage resources than ten years ago.

Commission Response

The requirements in the rule are based only in part on the 2012 Quanta Report and the associated requirements in the rule remain appropriate. The requirement to fix any known, acute issues that arose from winter weather conditions during the 2020–2021 winter weather season addresses RWE's concerns with the changed resource mix in the ERCOT power region.

Gas Supply

Oncor Cities recommended that the commission require a generation entity to demonstrate that its gas supply is weatherized to a set of specific and definable standards and should coordinate with the Railroad Commission of Texas (RRC) on any aspect of the rulemaking concerning weatherization for gas facilities.

Commission Response

The commission declines to adopt Oncor Cities's recommendation to require a generation entity to demonstrate that its gas supply is weatherized. Neither the commission nor a generation entity can compel weatherization compliance from its gas supplier. Moreover, many generation entities do not have a choice of gas fuel suppliers for electric generation. Finally, in Section 5 of SB 3, which amended §86.044 of the Natural Resources Code, the Legislature directed the RRC to develop weatherization standards for gas fuel suppliers. The commission is working closely with the RRC to develop a weatherization framework that covers the electric-gas supply chain that is critical for electric generation.

Critical Natural Gas Facilities

In addition to weather emergency preparedness reliability standards, the Legislature passed legislation requiring the commission and the RRC to collaborate on developing a process to identify certain natural gas facilities and entities that are critical to the electric supply chain and designate those facilities as critical load during energy emergencies. Once designated critical, these natural gas facilities will be required to provide electric utilities with certain information to assist in establishing load shed and power restoration priorities. Public Citizen expressed concern that the RRC's proposed rules related to critical natural gas facilities do not require enough information about those facilities to be shared with electric utilities to be able to appropriately designate the facilities as critical to electric generation and to prioritize their needs. Public Citizen stated that this will prevent the commission from meeting the goals it sets for itself in this rulemaking. Public Citizen stated that the commission should recommend that the RRC establish a better process for designating critical gas suppliers.

Commission Response

The commission has no authority to direct rulemaking projects taken by the RRC. The two state agencies are collaborating on rulemaking efforts to direct what information natural gas facilities must provide to the commission, RRC, and ERCOT. The commission will continue to collaborate with the RRC on the issue of critical load designations of natural gas facilities, but this issue is beyond the scope of this rulemaking.

Distributed Energy Resources

TAEBA recommended the commission modify existing rules to ensure that distributed energy resources can deliver and be compensated for the range of grid services they can provide. According to TAEBA, a near-term focus on augmenting demand-side resources' ability to meet reliability needs is squarely consistent with PURA §38.075 and would complement the commission's efforts to enhance both supply-side reliability and reliability of the transmission and distribution utility infrastructure relied upon to deliver power to Texans under all weather conditions. TAEBA stated that the commission could exercise its authority conferred in PURA to initiate and implement a range of policies and regulations that recognize distributed energy resources' ability to contribute to resource adequacy in a manner that mitigates catastrophic grid disruptions, shields customers and utilities from extreme financial risk, increases resource diversity, and enhances system flexibility.

Commission Response

The commission disagrees with TAEBA's interpretation of PURA §38.075. The statute requires the preparation of transmission facilities to be able to provide service in weather emergencies. TAEBA's proposals are beyond the scope of this rulemaking and are more properly addressed as a part of the commission's market design efforts.

Confidentiality

Calpine and TCPA requested modifications to subsections (a) and (b) to address the commercial and operational sensitive nature of the winter weather readiness reports to be submitted to the commission and ERCOT. Similarly, TPPA requested the commission confirm that entities would be permitted to submit information confidentially. TEC also recommended adding a new, wholly different subsection (h) pertaining to the confidential critical energy infrastructure information that may be provided in the reports. Conversely, Oncor Cities requested that the winter weather readiness reports submitted by generation entities and TSPs be made publicly available.

Commission Response

The commission makes no revisions to the rule in response to these comments. An entity required to submit information to the commission may assert the confidentiality of that information in accordance with §22.71 of this title (relating to Filing of Pleadings, Documents, and Other Materials). ERCOT also has procedures to address information that is submitted as confidential in its Protocols.

The commission declines to explicitly require that winter weather readiness reports be made publicly available because these reports may contain confidential critical energy infrastructure information or competitively sensitive information.

Subsection (a), Application

The proposed subsection would make the rule applicable to the ERCOT and to generation entities and TSPs in the ERCOT power region.

Calpine recommended that the commission provide a good cause exception to the rule for resources that are mothballed or are in a period of extended outage through the winter weather season. Similarly, TCPA offered language that would directly exempt these units from being subject to the rule. TCPA also suggested that ERCOT consider whether a resource has been seasonally mothballed or is scheduled to be retired when determining an appropriate cure period. Although these comments were made in reference to subsections (d) and (c) respectively, the substance relates to the application of the rule, and is therefore addressed here.

Commission Response

The commission agrees that mothballed generation resources that will not be available to provide energy or ancillary services during the 2021-2022 winter weather season should not be required to adhere to the requirements of this rule. However, the generation entity in control of the generation resource must have received an ERCOT-approved notice of suspension for the 2021-2022 winter weather season prior to December 1, 2021 to exempt its resource from the requirements of this rule. If the generation entity intends to return the mothballed resource to service during the winter weather season, the resource is not required to comply with this rule until it is returned to service. The commission, therefore, revises subsection (a) of the rule accordingly.

Paragraph (b)(1), Definition of Cold Weather Critical Component

The proposed paragraph would define the term "cold weather critical component" as "any component that is susceptible to freezing, the occurrence of which is likely to lead to unit trip, derate, or failure to start."

AEP Companies, CenterPoint, LCRA TSC, Oncor, TNMP, and TPPA commented that the definition is focused on generation resources and requested either that it not apply to transmission facilities or that it be changed to expressly address transmission facilities. TPPA and Sharyland recommended a revision to the definition so that it would apply more clearly to both generation resources and transmission facilities. Oncor requested clarification that "unit trip, derating, or failure to start" refers to a generation unit's tripping, derating, or failure. Oncor stated that the term "cold weather critical component" should apply only to TSP-owned high voltage switching stations and the high voltage portions of TSP-owned load-serving substations. Oncor further recommended that the commission specifically exclude the distribution-voltage portions of substations, as well as transmission lines, from this definition. Similarly, TNMP requested the addition of the following definition to reduce the scope of the rule: "Transmission system(s) and facility(ies) - Means a high-voltage switching station equipment or substation high-side load serving equipment."

Commission Response

The commission revises the definition of "cold weather critical component" to expressly apply to both generation entities and TSPs. The commission has applied elements of both TPPA's and Oncor's recommendations and addresses TNMP's request. The revised definition captures all transmission-voltage components within the fence surrounding a TSP's high-voltage switching station or substation. This amended definition is also appropriate for the standards in this rule because it focuses preparations on the transmission components most susceptible to preventable outages that could affect system reliability during a winter weather emergency.

TEC requested that the definition of cold weather critical components be changed to include components that will cause a generation resource to trip offline and which may reasonably be protected against freezing. TEC stated that this change would provide certainty to resource owners and TSPs regarding applicable components and would prioritize components that can be protected against freezing by applying protective measures. According to TEC, if covered components are not limited to those that can reasonably be protected, entities will lack certainty regarding regulatory compliance; the universe of eligible components will be undefined and may include components that cannot be reasonably protected.

Commission Response

The commission declines to adopt TEC's recommendation to expressly limit the definition to components that can be protected against freezing by applying protective measures. The commission expects that an entity will use appropriate professional judgment to identify and protect those components that are critical to continuous operation to ensure that its implementation of the rule has a meaningful result.

LCRA requested deletion of the term "cold weather critical component." LCRA asserted that the proposed definition could potentially include millions of individual components that make up a generating facility. LCRA claimed that any component of a generation resource that fails could in theory lead to the resource tripping offline, becoming incapable of starting, or derating its available capacity. Moreover, LCRA suggested that any component could theoretically freeze. Because the definition, in LCRA's opinion, implicates every component of every generation resource, the rule creates an "impossibly broad and unenforceable standard" that leaves generation entities with little understanding of what preparations need to be undertaken for winter operation.

Commission Response

The commission declines to adopt LCRA's recommendation because its hypothetical scenarios stray beyond the concept of a "critical component." Not every piece of equipment in a generation resource is critical to the reliable operation of that resource. Moreover, both FERC, in its February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations report (2021 FERC report), and the 2012 Quanta Report place the identification of critical components and freeze protection schemes near the top of the lists in their respective recommendations. The commission expects that an entity will use appropriate professional judgment to ensure that its compliance with the rule will produce a meaningful result.

Vistra stated that the definition of cold weather critical component goes beyond focusing on a unit failure that would affect system reliability in the ERCOT power region, which was the goal of SB 3. Instead, Vistra continued, the definition identifies a critical component as one which, if it freezes, "is likely to lead to unit trip, derate, or failure to start." Vistra stated that this definition could result in an unworkable standard because hundreds of thousands of components contribute in a way to maximize output. According to Vistra, derates are common and largely unavoidable, especially in extreme conditions, and provided an example of environmental monitoring equipment becoming impacted by weather conditions, requiring an environmental derate while the issue is investigated and remediated. Vistra indicated that a better definition would cover a non-weatherized component failure caused by freezing that would lead to a total and immediate loss of unit output, and TCPA made a similar comment.

Commission Response

Although a derate may be necessary in a weather emergency to address an issue, as described in Vistra's comments, the definition does not refer to such a scenario. Rather, the definition is limited to the freezing of a cold weather critical component being the direct cause of a derate. Accordingly, the commission declines to adopt Vistra's recommendation.

Enel and RWE requested a revision to clarify that cold weather critical components are required to function in defined operating ranges. Capital Power stated that wind turbine blades are not susceptible to freezing (although they are susceptible to icing) and requested that wind turbine blades and poor road conditions that do not allow personnel to access facilities be excluded from the definition.

Commission Response

The commission addresses the issue of operating ranges, which was raised by Enel and RWE, in its response to comments on paragraph (c)(1) of the rule.

The commission declines to adopt Capital Power's recommendation to exclude specific components from the definition of "cold weather critical component". However, the commission finds that addition of a reference to icing in the definition is appropriate and revises the paragraph accordingly.

The commission also revises the definition to refer to a resource rather than an undefined "unit."

Paragraph (b)(2), Definition of Energy Storage Resource

The proposed paragraph would define energy storage resource as "[a]n energy storage system registered with ERCOT for the purpose of providing energy or ancillary services to the ERCOT grid and associated facilities behind the system's point of interconnection necessary for the operation of the system."

TCPA and Calpine requested deletion of the definition. They stated that energy storage resources are generation resources and, therefore, can be covered by the definition of generation resource. TEC requested that the definition be changed to refer to a facility "that sells" energy or ancillary services to better track the language of PURA §35.0021(a).

Commission Response

The commission declines to adopt the recommendations to delete the definition of energy storage resource or change the definition of generation resource. This rule applies within the ERCOT power region: therefore, the definition's similarity to the comparable definition in the ERCOT Protocols is appropriate.

However. consistent with the discussion below regarding the definition of generation resource, the commission revises the definition of energy storage resource to limit the application of the term only to those associated facilities controlled by the generation entity and that are not part of a manufacturing process that is separate from the generation of electricity.

Paragraph (b)(4), Definition of Generation Resource

The proposed paragraph would define generation resource as "[a] generator capable of providing energy or ancillary services to the ERCOT grid and that is registered with ERCOT as a generation resource, as well as associated facilities behind the generator's point of interconnection necessary for the operation of the generator."

Calpine and TCPA requested that the definition include only facilities owned and controlled by the generator and described an arrangement where a generator uses steam from an industrial process not controlled by the generator. TIEC requested revision of the definition to reference "auxiliary" facilities instead of "associated facilities," with the intent of excluding distinct manufacturing processes and avoiding disputes about whether non-generating industrial facilities that consume steam or may otherwise be electrically connected to a cogeneration unit are also required to be weatherized. TEC requested that the definition be changed to refer to a facility "that sells" energy or ancillary services to better track the language of PURA §35.0021(a).

Commission Response

The commission agrees with Calpine and TIEC that the definition of generation resource should be limited to those associated facilities controlled by the generation entity, and revises the rule accordingly. The commission, however, declines to further limit the definition to apply to associated facilities that are both controlled and owned by the generation entity because some associated facilities could be controlled contractually rather than through ownership.

The commission also declines to adopt TIEC's recommendation to change "associated" to "auxiliary." According to TIEC, the term "auxiliary" refers to a more limited set of manufacturing equipment. As a result, equipment or facilities that could directly impact the generation resource's operations might remain unprotected. The commission agrees with TIEC that the scope of the rule should not apply to equipment or facilities that are part of a manufacturing process that is separate from the generation of electricity and revises the definition accordingly.

Paragraph (b)(5), Definition of Inspection

The proposed paragraph would define inspection as follows: "The activities that ERCOT engages in to determine whether a generation entity is in compliance with subsection (c) of this section or whether a TSP is in compliance with subsection (f) of this section. An inspection may include site visits; assessments of procedures; interviews; and review of information provided by a generation entity or TSP in response to a request by ERCOT, including review of evaluations conducted by the generation entity or TSP or its contractor. ERCOT will determine, in consultation with the commission, the number, extent, and content of inspections and may conduct inspections using both employees and contractors."

Oncor requested that either this definition of inspection or subsection (g) be clarified to explicitly state that ERCOT's inspection authority under the rule derives from the commission's statutory authority under PURA §14.204, which allows the commission to authorize an agent to "inspect the plant, equipment, and other property of a public utility within its jurisdiction ... at a reasonable time for a reasonable purpose." Oncor also stated that ERCOT's inspection program should require that inspections occur at a reasonable time with reasonable advanced notice to the TSP and that the rule should recognize that ERCOT-conducted inspections should comply with applicable NERC requirements, including a TSP's physical security plan for station access.

Commission Response

The rules adopted herein implement PURA §38.075(b), which requires ERCOT to inspect transmission facilities in the ERCOT power region. While PURA §14.204 authorizes the commission and its designated agents to inspect plant, equipment, and property of a public utility, citation to this statute does not provide any added clarity to ERCOT's scope of authority to implement this rule. Similarly, the commission declines to incorporate a reference to the NERC requirements suggested by Oncor because it is unnecessary. However, the commission revises paragraphs (d)(1) and (g)(1) to require generation entities and TSPs, respectively, to admit ERCOT inspectors into areas of the resource or station that will be inspected. Because the safety of the inspectors and employees and the security of the resource and station are of paramount importance, the commission also expects all parties to take the appropriate safeguards during inspections.

TEC, Calpine, and TCPA recommended changes to the definition of inspection that would enable stakeholders to provide input into the policies and procedures of ERCOT's inspection of generation resources and transmission facilities. TEC requested that ERCOT adopt rules regarding the details of ERCOT-conducted inspections for the phase-one rule standards, and that the commission consider and adopt specific inspection protocols in the phase-two rule. According to

TEC, these actions would create transparency and consistency in the inspection framework and would allow market participants to clearly understand and provide feedback on the number, extent, and content of the inspections because these parameters would be formalized in rules. Calpine and TCPA requested that the commission require ERCOT to consult with stakeholders to create inspection criteria.

Commission Response

The commission declines to change the definition of inspection. An entity must comprehensively prepare its facilities for weather emergencies instead of focusing efforts on specific components of its facilities known to be included in ERCOT's inspection. The rule provides sufficient specificity for the inspections while giving ERCOT the flexibility to conduct the inspections in an efficient, and effective manner. The commission may consider specifying additional requirements for ERCOT inspections as part of the phase-two development of the weather emergency preparedness reliability standards.

The proposed definition of inspection contained a provision that requires ERCOT to determine the number, extent, and content of inspections in consultation with the commission. Because this provision imposes a requirement on ERCOT, the commission moves the provision from this definition to paragraphs (d)(1) and (g)(1). The commission revises the definition to specifically refer to paragraphs (1) of subsections (c) and (f) and to acknowledge that ERCOT needs the flexibility to prioritize its inspections based on risk level, as required by PURA §35.0021(c-1) and §38.075(c).

Paragraph (b)(6), Definition of Resource

The proposed paragraph would define resource as "[a] generation resource or energy storage resource."

Calpine and TCPA requested deletion of this definition on the basis that it is unnecessary because the definition of generation entity includes the term resource in it.

Commission Response

A definition of resource allows the defined terms "generation resource" and "energy storage resource" to be easily addressed jointly throughout the rule. Therefore, the Commission declines to adopt Calpine and TCPA's recommendation.

Proposed Paragraph (b)(7); Adopted Paragraph (b)(8), Weather Emergency Preparation Measures

The proposed paragraph would define weather emergency preparation measures as "[m]easures that a generation entity or TSP takes to support the function of a facility in extreme weather conditions, including weatherization, fuel security, staffing plans, operational readiness, and structural preparations."

TEC requested revision of the definition to incorporate the preparation standard articulated in PURA §35.0021. TCPA requested a revision to specify that the term is limited to aspects of the electric system under the generation entity's control or the TSP's control and cited fuel security as an example of something that should be excluded. Calpine also requested that fuel security be excluded. SEIA requested that the definition be limited to measures described in paragraphs (c)(1) and (f)(1) of the rule. TEC also requested that "including" be changed to "which may include,".

Commission Response

The commission declines to limit the definition of "Weather emergency preparation measures" as recommended by TEC, TCPA, Calpine, and SEIA. The definition describes measures that a generation entity or TSP may take to meet the requirements in paragraphs (c)(1) and (f)(1) of the rule. Those paragraphs address any relevant limitations. Accordingly, the commission deletes the non-exclusive list of types of measures at the end of the definition and instead addresses the types of measures in subparagraphs (c)(1)(A) and (f)(1)(A).

Other Terms

The AEP Companies noted that the definition of weather emergency preparation measures includes a term "extreme weather conditions" that is itself undefined. Capital Power requested a definition of "extreme weather" that would allow generation entities to determine the definition of cold weather based on the unit's location, the owner's experience with operations during cold weather events, and additional commonly used industry resources.

Oncor Cities requested a definition of "winter weather conditions," and APA and ACP requested a definition of "cold weather." APA and ACP also requested a definition of "weather emergency."

Commission Response

The commission accepts APA and ACP's recommendation to define "weather emergency." This rule sets reliability standards for weather emergencies as required by PURA §35.0021(b) and §38.075(a). Therefore, the commission adds a new paragraph (7) to define weather emergency as "a situation resulting from weather conditions that produce a significant risk for a TSP that firm load must be shed or a situation for which ERCOT provides advance notice to market participants involving weather-related risks to the ERCOT power region."

The commission declines to add a definition of extreme weather, extreme weather conditions, winter weather conditions, or cold weather as recommended by the commenters. The commission's new definition of "weather emergency" will provide the context and clarity sought by the commenters.

Subsection (c), Weather Emergency Preparedness Reliability Standards for a Generation Entity

The proposed subsection would establish weather emergency preparedness reliability standards and related procedures for generation entities in preparation for the 2021–2022 winter weather season.

Calpine and TCPA requested that the commission remove "phase one" from the title of the subsection of the rule. Calpine stated that the term could be interpreted to imply that this rule is not final and, therefore, does not fully comply with the statutory deadline for implementation of the reliability standards imposed by SB 3. TCPA stated that there is no need to designate phases in the rule; when a future phase is implemented, the rule will be amended to reflect those new requirements.

Commission Response

The commission agrees that "phase one" in the title of this subsection is not necessary, and deletes the phrase accordingly.

Paragraph (c)(1), Reliability Standards

The proposed paragraph would establish weather emergency preparedness reliability standards for generation entities in preparation for the 2021–2022 winter weather season.

Fuel-Related Standards

TAEBA stated that the proposed rule does not establish any fuel-related standards or require any specific measures to reduce fuel supply risk. City of Houston requested the addition of a requirement that generators must contract with fuel suppliers and fuel delivery entities with weatherized facilities. City of Houston stated that the cost and effort made by a generator to weatherize its facilities would be wasted if it does not have access to fuel because its suppliers did not weatherize their facilities. City of Houston acknowledged that this might not be possible for the 2021-2022 winter weather season and suggested that generators be required to implement this requirement to the extent possible. City of Houston also requested that the commission require a generator to submit information on its existing fuel supply and fuel delivery contracts that it is unable to modify to require the contractor to weatherize its facilities and fuel sources. City of Houston stated that this requirement will identify at-risk fuel supplies for the 2021-2022 winter weather season and assist the commission in determining the state's preparedness and in preparing the commission' s weather emergency preparedness report to the Legislature.

Commission Response

The commission declines to establish fuel-related standards, require a generation entity to contract with fuel suppliers and fuel delivery entities with weatherized facilities, or require a generation entity to submit information on its current fuel contracts to the commission in this rule. The City of Houston's recommendations are beyond the scope of this rulemaking, which is focused on whether the generation entity itself has properly prepared its facilities and personnel for a weather emergency.

<u>*Technology-Specific Standards*</u>

Savion and Enel requested that the commission promulgate technology-specific requirements. Enel stated that many of these requirements apply broadly across technologies, such as proper documentation; identification of operating limitations and critical failure points; and training and drills, but that some requirements cannot be applied broadly across resources. Enel made resource-specific recommendations for wind, solar, and battery technologies. Similarly, Savion observed that neither the 2012 Quanta Report nor the 2011 FERC/NERC Report addressed solar or energy storage technologies. Savion argued that the commission needs to promulgate standards for solar and energy storage technologies before December 1, 2021 to prevent developers of these technologies from being exposed to $1,000,000 per day penalties for non-compliance.

Commission Response

The commission declines to include technology-specific requirements as requested by Savion and Enel. Technology-specific requirements are not appropriate or practical because technology continuously evolves. The generation entity is in the best position to know what is needed to comply with the rule for a specific resource. Subparagraphs (c)(1)(A) and (B) are adapted directly from the 2012 Quanta Report and the 2011 FERC/NERC Report. The commission expects a generation entity to apply appropriate professional judgment to comply with the rule to produce meaningful results.

December 1, 2021 Completion Deadline

Proposed subsection (c)(1) would also establish a December 1, 2021 deadline for compliance with the weather emergency preparedness reliability standards for generation entities. SEIA requested clarity about how the commission will address compliance in scenarios where the entity has requested a good cause exception under paragraph (c)(6). SEIA stated that an entity will have to make judgment calls on how to comply with paragraph (c)(1) without an assurance of whether its good cause exception has been granted.

Commission Response

In all of its actions related to complying with the requirements of paragraph (c)(1), a generation entity must use its best efforts. Even if a generation entity notifies commission staff of an assertion of good cause for noncompliance with the December 1, 2021 deadline, as provided by paragraph (c)(6), the generation entity must nevertheless use its best efforts to comply with paragraph (c)(1), including providing a plan to bring its resource(s) into compliance and a schedule by when the resource(s) will be in compliance with the paragraph.

A generation entity must not use a request for a good cause exception as a means to delay compliance with the rule. If commission staff disagrees with the entity's assertion of good cause, the generation entity may be subject to enforcement if it did not use its best efforts to comply with the rule requirements for which it sought a good cause exception.

Subparagraph (c)(1)(A), Preparations for Sustained Operation

The proposed subparagraph (c)(1)(A) would establish preparations necessary to ensure the sustained operation of all cold weather critical components during winter weather conditions, such as chemicals, auxiliary fuels, and other materials, and personnel required to operate the resource.

Calpine, Capital Power, Exelon, RWE, TEC, TCPA, TIEC, and Vistra requested that the commission limit the required weatherization measures to those that are reasonable and feasible. These commenters stated that requiring "all preparations necessary to ensure sustained operation" imposes a performance standard. Calpine stated that requiring "all" measures is overly broad because generation entities often learn of which measures are required to sustain operations from experience. Exelon and Capital Power stated that the qualifier is overly broad, covering an almost limitless set of weatherization preparations, without regard to duplication of preparations, their cost/economic benefits, or whether they are tied to the 2012 Quanta Report or an identified risk based on historical performance. TEC stated that without a reasonableness standard the rule would create limitless compliance requirements. TIEC stated that use of the word "ensure" suggests entities could be held at fault for failures beyond their control, thus transforming the rule into a perceived performance standard that could discourage investors from directing resources to the

ERCOT market. Capital Power suggested that “all necessary actions” should be further described to clarify what preparation steps would be required in order to comply with the rule.

Commission Response

The commission agrees that the rule should impose a preparation standard on a generation entity rather than a performance standard on the generation resource. The commission finds the adjective “necessary” could be interpreted as requiring a certain level of resource performance and, thus, replaces it with “intended.” To intend is to plan or to have something in mind as a purpose or goal. The use of “intended” in this paragraph clarifies that the rule is a preparation standard. Without limitation, commission staff may take into consideration an entity’s compliance with its own plan as a measure of best efforts in meeting the requirements of the rule.

As explained above in the discussion of the December 1, 2021 deadline in paragraph (c)(1), generation entities must use best efforts to meet the requirements specified throughout paragraph (c)(1). The commission changes “All actions” to “Best efforts” to reflect this preparation standard.

TPPA, Capital Power, LCRA, RWE, Enbridge, and APA/ACP requested that the commission define “sustained operation" to specify the length of operation required for compliance. Enbridge provided an example that that there may be fuel interruptions or extreme conditions that may cause unavoidable disruption to the equipment's operation, which might impact the “sustained operations” of the entity. TIEC suggested that the commission and ERCOT should focus oversight activities on ensuring that generators take appropriate steps to reasonably winterize their generation units before cold weather occurs, rather than penalizing generators for the ultimate outcome, and to that end suggested replacing "ensure" with "allow" to precede "sustained operations."

Commission Response

The commission declines to define the term "sustained operation" because the regulatory standard of the provision is the preparations taken in advance of operations and not the amount of time an entity is capable of operating. Assuming the generation entity can demonstrate it used its best efforts intended to ensure sustained operation of the generation resource, the compliance standard should be met under the rule.

Enbridge, Enel, NextEra, and RWE stated that the rule needs to take equipment design limitations into account. NextEra stated that the proposed rule could require an operator to operate outside its design parameters and potentially void manufacturer warranties, damage equipment, or create unsafe operating conditions.

Enel recommended that, "as a baseline, no resource should be required to operate outside of limitations." Enbridge requested that the commission adopt language that would, instead, require winter weather preparation measures that would ensure that cold weather critical components perform "as originally designed" during winter weather conditions.

Commission Response

Although a generation entity must use its best efforts to comply with the requirements of paragraph (c)(1), a generation entity is not required to operate a resource outside of its limitations. However, the generation entity must use appropriate professional judgement to determine those limitations and must not set them in a manner that unnecessarily constrains the capabilities of the generation resources.

The commission replaces "preparations" with the defined term "weather emergency preparation measures" to clarify its intent. Consistent with its discussion of the definition of weather emergency preparation measures, proposed paragraph (b)(7), adopted paragraph (b)(8), the commission adds types of weather emergency preparation measures listed in the proposed definition to paragraph (c)(1)(A).

Subparagraph (c)(1)(B), Installation of Adequate Preparation Measures

The proposed subparagraph (c)(1)(B) would establish installation of adequate preparations necessary to ensure the sustained operation of all cold weather critical components during winter weather conditions, the failure of which could cause an outage or derate.

TEC requested the merger of subparagraph (c)(1)(B) into subparagraph (c)(1)(A) to create a list of possible measures, because it stated that a prescriptive list of specific measures may be inappropriate for certain resources or may inadvertently exclude needed activities best determined by operational personnel. Similarly, LCRA requested the commission move the concept of freeze-susceptible components into subparagraph (c)(1)(A), along with other modifications it stated better reflected the recommendations of the 2012 Quanta Report.

Commission Response

The commission declines to adopt TEC's and LCRA's recommendation to combine subparagraphs (c)(1)(A) and (c)(1)(B) because the subparagraphs address different requirements. Subparagraph (c)(1)(A) is intended to ensure generation entities use their operational expertise to prepare cold weather critical components for operation in winter weather conditions. Although LCRA stated that the term "cold weather critical component" is neither a statutorily defined term nor an industry term of art, the concept is not foreign to industry experts. For example, the term was included in the 2021 FERC report released on September 23, 2021.

Subparagraph (c)(1)(B), on the other hand, addresses specific recommendations developed in the aftermath of the February 2011 winter weather event. Therefore, the commission declines to make changes in response to these comments.

Calpine and TCPA stated that the actions required by subparagraph (c)(1)(B) may not be feasible to implement by December 1, 2021. Instead, they proposed changes to the rule that would allow generation entities to create an inventory of resources that would be used to prepare the generation resource for operation in extreme winter weather. Additionally, Calpine stated that the actions in the draft rule are not necessarily appropriate for extreme winter weather that is typical in the ERCOT power region.

Commission Response

The commission declines to remove the specific preparation measures enumerated in this subparagraph from the rule. Generation resources were not well prepared for winter storms in 2011 and 2021. Lessons learned from both the 2011 and 2021 winter weather events form the foundation for these preparation requirements, and future revisions to the rule may build upon them. The commission expects that a generation entity will use appropriate professional judgment when using its best efforts to implement weather emergency preparation measures. In addition, a generation entity is not required to implement a particular weather preparation measure specified in the rule if there is good cause for not doing so.

Several parties commented on the requirement to install adequate wind breaks for resources susceptible to outages or derate caused by wind. Enbridge expressed concern that the December 1, 2021 deadline to install these wind breaks may not be feasible. TAEBA sought clarification that the commission was not requiring wind generation resources with controls that shut off the turbine or reduce the turbine's revolutions per minute to install wind breaks, because these automated safety controls could be interpreted as an outage or deration. TPPA contemplated this requirement applied only to a thermal generation resource that is exposed to wind, and both TPPA and Capital Power stated that a strict reading of this rule could require wind generation resources to install wind breaks. TPPA and Capital Power requested that the commission tighten this language to better reflect its intent.

Commission Response

The commission declines to change the rule to explicitly exempt any type of resource from the requirements of subparagraph (c)(1)(B). The commission expects that a generation entity will use appropriate professional judgment to ensure that its compliance with the rule produces a meaningful result. For example, the installation of wind breaks at a wind generation resource would be an illogical interpretation of the rule requirements. In response to TAEBA's comment, the commission confirms that generation output limitations caused by predefined operational controls would not constitute a forced outage or deration in a winter weather emergency.

APA/ACP, Exelon, LCRA, and TCPA each stated that installation of enclosures on sensors for cold weather critical components can be impractical or ineffective in certain cases.

Commission Response

The commission references the 2012 Quanta Report and 2011 FERC/NERC Report as a basis for understanding the lessons learned from past experiences with severe winter weather conditions. To that end, if enclosing certain sensors on the generation resource would be counterproductive, a generation entity can explain in its winter weather readiness report required by paragraph (c)(2) that such an enclosure would render the sensor inoperable under the design or operating limits.

Capital Power and LCRA commented on the requirement to maintain freeze protection components for all equipment, including fuel delivery systems. Capital Power requested the commission provide a definition of a freeze protection component. For example, it wondered whether insulation would be considered a freeze protection component. LCRA noted that not all equipment has its own freeze protection components. LCRA requested further clarification that generation entities should only be responsible for fuel delivery systems it owns and operates.

Commission Response

The commission declines to define "freeze protection component" or to enumerate specific components that comprise the category of freeze protection components. Generation entities have a variety of tools and options to protect equipment from freezing during a winter weather emergency. The commission expects a generation entity to rely on its expertise and professional judgment to determine what tools are best suited to protect its specific equipment and to maintain those tools so that they provide the required protection. However, the commission agrees to clarify that only fuel delivery systems controlled by the generation entity are required to have freeze protection equipment. Accordingly, the commission revises subparagraph (c)(1)(B).

Capital Power argued that monitoring systems for cold weather critical components should not be required for wind generation resources. Capital Power stated that anti-icing and de-icing technologies are not available in the United States, according to filings and presentations made by GE, Siemens, and Vestas, and therefore the systems to monitor for icing or freezing do not exist either. In support of its position, Capital Power also noted that NERC does not require installation of monitoring systems in regions that experience colder weather than Texas.

Commission Response

The commission declines to change the rule as recommended by Capital Power. NERC's new Cold Weather Reliability Standards are focused on planning. The commission's rule is focused on preparing. The two sets of federal and state regulations will work together to help achieve more reliable outcomes during winter weather emergencies. Moreover, the substitution of NERC's requirements for the ones in the proposed rule does not address the preparation set forth in PURA §35.0021.

Although Enbridge noted the inclusion of a good cause exception process in subsequent parts of the rule, it suggested that generation entities be allowed to either install the required preparation measures or submit a schedule for the installation of the measures to explicitly accommodate supply chain delays. Enbridge further clarified that such a schedule should only be permitted when the generation entity confirms it is unable to make the change without approval, involvement, and direction of the manufacturer.

Commission Response

The commission declines to change the rule as proposed by Enbridge. Generation entities should make their best efforts to complete the actions listed in paragraph (c)(1). The good cause exception provision contained in paragraph (c)(6) is the appropriate method for communicating these types of issues to the commission and ERCOT.

In response to the proposed requirement to establish a schedule to test freeze protection components on an ongoing monthly basis, TCPA stated that winter is the only season in which it would be feasible to test these components in a simulated cold weather environment.

Commission Response

The commission agrees with TCPA that monthly testing should be conducted during the winter weather season as a best practice preparation measure. The commission revises the rule to require testing at least once each month from November through March.

Subparagraph (c)(1)(C), Reoccurrence Prevention

The proposed subparagraph (c)(1)(C) would require a generation entity to take all actions necessary to prevent a reoccurrence of any cold weather critical component failure that occurred in the period between November 30, 2020, and March 1, 2021.

Calpine, TPPA, TEC, LCRA, Exelon, Vistra, TAEBA, SEIA, and APA/ACP argued that this provision is overly broad by requiring an undefined and potentially limitless set of actions that must be taken to "prevent" a recurring cold weather critical component failure. Moreover, the parties echoed comments filed concerning subparagraph (c)(1)(A) in that the requirement to take steps necessary to prevent a failure transforms the rule into a performance standard. According to these commenters, it is not feasible for a generation resource to guarantee it can prevent a component failure; however, it is feasible for a generation resource to guarantee it will take actions necessary to address a prior failure to reduce the likelihood of reoccurrence. Calpine proposed edits that would, in its opinion, maintain the commission's objective of implementing the rule as a preparation standard. Capital Power suggested the commission consider replacing the word "prevent" with the word "mitigate" to make clear that generation owners are not required to adhere to a strict level of perfection at any cost, human or material. Exelon proposed to insert "reasonably necessary". TAEBA and SEIA similarly requested clarification that this provision would not require generation entities to take any actions that would put at risk the health or safety of employees or contractors.

Commission Response

Generation entities must use their best efforts to prevent repeated failures of cold weather critical components. The commission revises subparagraph (c)(1)(C) for consistency with the standards established in subparagraph (c)(1)(A). In addition, the commission reiterates that in no instance is a generation entity required to take an action that presents a real risk of bodily harm to its employees or contractors.

TAEBA and SEIA requested that the commission clarify that the proposed rules should not be interpreted to require a generation entity to implement a weather emergency preparation measure that is inconsistent with good utility practice or is contrary to the design or operating limitations of a generation resource. SEIA further argued that the requirements of this subsection should be interpreted in a manner that does not require a generation entity to implement weather emergency preparation measures that exceed the design or operating limitations prescribed by the original equipment manufacturer.

Commission Response

As the commission stated in response to comments on subparagraph (c)(1)(A), although a generation entity must use its best efforts to comply with the requirements of paragraph (c)(1), a generation entity is not required to operate a generation resource outside of its

limitations. However, the generation entity must use its professional judgement to determine those limitations and must not set them in a manner that unnecessarily constrains the capabilities of its resources. In addition, the generation entity can engage in good utility practice to the extent doing so is consistent with the rule's requirement for the use of best efforts.

TPPA and Enel suggested that resource related issues occurring during the period between November 30, 2020, and March 1, 2021, might implicate situations unrelated to operation during winter weather. For example, Enel requested clarification that outages and derations related to resources following operational requirements would not be implicated by this provision. TPPA requested that this requirement be limited to failures that occurred directly due to winter weather, rather than one-off occurrences unrelated to cold weather operations.

Commission Response

The commission agrees with TPPA and Enel's recommendation to clarify that subparagraph (c)(1)(C) to applies to failures that occurred due to winter weather conditions between November 30, 2020 and March 1, 2021, and revises the subparagraph accordingly.

Capital Power and Enbridge requested the commission explicitly acknowledge that blade turbine icing cannot be completely prevented.

Commission Response

The commission finds the recommended change to be superfluous, as the rule does not attempt to address every unique characteristic of every generation resource type.

LCRA requested that the commission be explicit that no provision of the rule will be interpreted as requiring a generation entity to redesign any subsystem of an existing generation facility. Specifically, LCRA stated that requiring generation entities to take "all actions" to prevent a weather-related failure hypothetically could require the entity to redesign and rebuild its resource.

Commission Response

As noted above, the commission revises subparagraph (c)(1)(C) for consistency with the standards established in subparagraph (c)(1)(A). This change deletes "all actions" and requires generation entities to use their "best efforts" to address the failures of cold weather critical components. The generation resource operator must decide how best to comply with the requirements of this rule; therefore, the commission declines to make the change recommended by LCRA.

Subparagraph (c)(1)(D), Training

The proposed subparagraph (c)(1)(D) would require a generation entity to provide training on winter weather preparations to operational personnel. Calpine and TCPA stated that generation resources must have employees who are trained not only in the necessary winter weather preparation standards but also in related operations to ensure reliable performance during a winter weather emergency. They each provided similar changes to clarify that training would occur on preparations and operations and be provided to relevant personnel. However, Oncor Cities expressed concern about the lack of specificity in what training programs will be required, leaving the requirement open for broad interpretation. Oncor Cities stated that a rule that is open for broad interpretation and lacks compliance standards risks being ineffective.

Commission Response

The commission declines to adopt Oncor Cities' proposal for a standardized, specific training program for all generation resource types and operations procedures. The training programs must be flexible enough to meet resource-specific operational processes and weather emergency preparation measures. However, the commission agrees with Calpine's and TCPA's recommendation to focus the required training on winter weather preparations and operations and to deliver the training to relevant personnel. Delivering training on both winter weather emergency preparation measures and operations during weather emergencies will improve the effectiveness of operations personnel during weather emergencies. Accordingly, the commission adopts Calpine's recommended language revisions.

Enbridge requested that if the commission or ERCOT seek to enact specific requirements, they should be identified at the earliest possible opportunity so that generation entities would have time to submit comments on applicability and/or limitations.

Commission Response

Tex. Gov't Code §2001.029 requires the commission to consider public comment on the proposed rule prior to adopting any new regulations.

Subparagraph (c)(1)(E), Design and Operating Limitations

The proposed subparagraph (c)(1)(E) would require a generation entity to determine the minimum design temperature, minimum operating temperature, and other operating limitations based on temperature, precipitation, humidity, wind speed, and wind direction.

Calpine, Cities, TPPA, TCPA, LCRA, and Exelon stated that this provision does not specify an engineering standard to reference. Accordingly, they suggested a generation entity should be permitted to rely on operational history because a generation entity may have had operational experiences that diverge significantly from the resource's original design criteria. These commenters requested flexibility to base their resources' operating limitations on the lowest temperatures experienced by that resource.

Commission Response

The commission accepts the recommendation that a generation resource's operational limitations may be determined using operational history. Such operational history takes into account the February 2011 and 2021 winter events, which would be consistent with the legislative intent to take prior recent events into account in this rule. The commission, therefore, revises the rule accordingly.

Enbridge and APA/ACP requested the commission allow a generation entity to select which design and operating conditions are relevant to a specific resource and provide that data to the commission because not all ambient conditions apply to all resource types and technologies. Both parties presented changes to provide this flexibility.

Commission Response

The commission declines to adopt Enbridge's and APA/ACP's recommendation to allow a generation entity discretion to choose which conditions are relevant to a specific generation resource. Reporting and review of design and operating limitation criteria are specific recommendations from the 2012 Quanta Report. The reported design and operating criteria do not impose a particular set of weather emergency preparation measures the entity must take. If particular conditions are not impactful on a particular generation resource, then the generation entity does not need to prepare for those conditions.

TEC suggested adding a new requirement to subsection (c)(1) that would require a generation entity to identify certain weather preparation measures that must be taken just in advance of a season or a predicted storm in order not to impact the resource's ability to maximize output of energy in other seasons.

Commission Response

Given that the focus of this rulemaking project is on the 2021-2022 winter weather season, the commission declines to add such a provision to the rule. However, the commission may consider TEC's recommendation in a future rulemaking project related to phase two weatherization standards.

Paragraph (c)(2), Generation Entity Winter Weather Readiness Report

The proposed paragraph would require that a winter weather readiness report with an attestation be submitted on a form prescribed by ERCOT and developed in consultation with commission staff. TPPA and Vistra requested an opportunity for stakeholder input into the development of the form. Capital Power requested that the form be specific to generator type to avoid confusion.

Commission Response

Given that the focus of this rulemaking project is on the 2021-2022 winter weather season, the commission declines to add a period of stakeholder review into the development of the winter weather readiness report form. Use of a form does not prevent a generation entity from including information that it considers relevant in its report.

The proposed paragraph would also require that a winter weather readiness report include a notarized attestation. Calpine, Enbridge, Exelon, Savion, TCPA, TIEC, and TPPA requested changes to the requirement that the attestation be sworn to by an officer of the generation entity with responsibility for the resource's operations. TCPA, Calpine, and Exelon each claimed that in corporations with multiple generation entity affiliates it may be difficult to determine which office is the highest-ranking representative. Similarly, TPPA noted that municipally owned utilities might be required to obtain the attestation of the city manager, mayor or city council.

Commission Response

The commission declines to make the requested changes. Given the importance of the information addressed in the winter readiness report, the commission is requiring that the

entity's highest-ranking representative, official, or officer with binding authority over the generation entity attest to the preparation measures conducted by the generation entity. With respect to the TPPA's request for clarification, the commission recognizes that the organizational structure of municipally owned utilities may vary and that a local government official or city council may be the highest-ranking authority for the generation entity. The commission clarifies that the rule does not require a resolution from an elected body or an attestation from an elected official to fulfill this rule requirement. The commission encourages each municipally owned utility to make a good faith effort to identify the appropriate person to provide the attestation.

With respect to the language in paragraph (c)(2), TEC stated that, because the activities identified in paragraph (c)(1) should not be exhaustive, may not be completed by the time of inspection (if the measures are seasonal or temporary in nature), or may be subject to a good cause exception, it would be more appropriate to attest to the actions taken "pursuant to" paragraph (c)(1) rather than describing activities taken "to complete" the requirements of paragraph (c)(1)

Commission Response

The commission declines to use the words "pursuant to" as suggested by TEC, because the word "complete" best describes the state of the best effort activities a generation entity is required to meet under paragraph (c)(1) when filing its winter weather readiness report. However, the commission revises subparagraph (c)(2)(B) to reflect in the attestation that a generation entity may request a good cause exception under paragraph (c)(6).

Paragraph (c)(3), ERCOT Inspection Checklist Form

The proposed paragraph would require ERCOT to develop a comprehensive checklist form.

Vistra and TCPA requested an opportunity for stakeholder input into the creation of the form and Capital Power requested an opportunity to review resource-specific forms before compliance is required. Specifically, TCPA and Vistra requested an opportunity to better understand the form to be able to provide feedback to ERCOT that would ensure information in the form was communicated clearly.

Commission Response

The commission declines to revise the rule in response to these comments. The development of an inspection checklist form is for the benefit of ERCOT's inspectors and is intended to provide information to the commission about ERCOT-conducted inspections. The commission has not included this requirement in the rule to give generation entities advance information on what ERCOT's inspectors may be specifically inspecting at the generation resource. Generation entities need to comprehensively prepare their generation facilities for weather emergencies instead of focusing on preparing specific components in anticipation of their inspection by ERCOT. Furthermore, in the development of its checklist form, ERCOT is necessarily limited to the standards in subparagraph (c)(1). However, the commission revises the rule to allow more than one checklist form to be used by ERCOT, since ERCOT's inspectors may need different checklist forms depending on such factors as the type of generation resource being inspected.

Calpine requested deletion of the reference to subsystems based on its assertion that the reference is duplicative and ambiguous.

Commission Response

The commission declines to adopt Calpine's recommendation to delete the reference to subsystems. The reference is appropriate to highlight the necessity of inspecting subsystems because a subsystem that malfunctions can have a significant impact on the operation of a generation resource.

Paragraph (c)(4), ERCOT Report on Generation Entity Winter Weather Readiness Report

The proposed paragraph would require ERCOT to file with the commission no later than December 10, 2021 a summary of the winter weather readiness reports filed under paragraph (c)(2) that addresses compliance of the generation entities with paragraphs (c)(1) and (2). Vistra and TCPA requested that the provision give a generation entity a reasonable period to appeal any determination of non-compliance reflected in ERCOT's report and to cure any identified deficiencies described in the report. TPPA asserted that the ERCOT report should be considered an inspection because of the proposed requirement that it address generation entities' compliance with paragraph (c)(1).

Commission Response

Because ERCOT will have only ten days to prepare and file this winter readiness report, the commission revises the rule provision to require a compliance report that addresses whether each generation entity submitted the report required by paragraph (c)(2) for each generation

resource under the generation entity's control and whether the generation entity submitted a notice asserting good cause for noncompliance under paragraph (c)(6). This rule revision makes moot TPPA's assertion and Vistra's request for an appeals process for an ERCOT determination in the report of noncompliance with paragraph (c)(1).

Calpine requested a January 15, 2022 deadline for ERCOT's report rather than the December 10, 2021 deadline in the proposed rule, arguing that the proposed deadline may not give ERCOT sufficient time.

Commission Response

The commission declines to make this change, because it has streamlined the requirements of what ERCOT must communicate in its December 10, 2021 report. Given the rule revision stated in the previous response, the commission finds there is sufficient time for ERCOT to prepare and submit the required winter readiness report by December 10, 2021.

Paragraph (c)(6), Good Cause Exception

The proposed paragraph would permit a generation entity to assert good cause for noncompliance with the specific requirements in paragraph (c)(1).

TPPA stated that good cause exceptions should be granted as a matter of enforcement discretion rather than in a contested case.

Commission Response

The commission accept TPPA's recommendation to eliminate the requirement for a contested case proceeding for a good cause exception to weather emergency preparation measures required in paragraph (c)(1). Although a contested case proceeding may provide additional transparency and formality to the review of a requested good cause exception, there are some types of good cause assertions that should not require a commission hearing, such as documented supply chain delays, that are likely to be resolved in a matter of days or weeks.

Instead of a mandatory contested case process, the commission concludes that assertions of good cause can initially be administered as enforcement investigations through which non-controversial requests can be efficiently reviewed and resolved and more complex, contentious issues can be addressed through a settlement process between the parties or the formal contested case process. The commission, therefore, revises paragraph (c)(6) accordingly.

Capital Power noted the lack of a deadline to request a good cause exception, and AARP requested a deadline for a good cause exception request and the notice to ERCOT of the request, and specifically requested that the deadline be before December 1, 2021, the date that a generation entity's winter weather readiness report is due. OPUC requested a process for reviewing a good cause exception, with a reasonable timeline for stakeholder comment.

Commission Response

The commission revises the rule provision to impose a December 1, 2021 deadline, the same date that a generation entity's winter weather readiness report is due under paragraph (c)(2). The commission declines to adopt OPUC's recommendation to add to the rule details of the review process for a request for good cause exception. The specifics of the review process should be addressed on a case-by-case basis, like all enforcement investigations are handled by the commission.

Enbridge requested a predetermination of good cause where the generation entity confirms that it is dependent on the equipment manufacturer for related preparations and the manufacturer confirms it cannot make the December 1, 2021 deadline. Enbridge also requested further detail on what documentation is required for a request for good cause exception.

Commission Response

The commission declines to make changes in response to Enbridge's requests. A determination of good cause may depend on the specific facts of the request and the provision is sufficiently specific with respect to required documentation given that the basis for a good cause exception may depend on the specific facts of a request.

LCRA requested clarification that a good cause exception request is not required to avoid redesign or reconstruction of a resource.

Commission Response

The commission makes no change to this provision in response to LCRA's request for the reasons addressed in its response to comments on subparagraph (c)(1)(c).

TIEC requested clarification that a good cause exception could allow a permanent exception to the requirements of paragraph (c)(1).

Commission Response

The commission clarifies clause (c)(6)(A)(iii)'s reference to a proposed compliance deadline for a request for a permanent exception.

AARP stated that an applicant for a good cause exception should be required to demonstrate it made every effort to meet the deadline; financial or cost considerations should not be sufficient to justify a good cause exception. In addition, AARP requested a limit on the maximum delay in meeting the weatherization deadline. AARP stated that delays should be short-lived and anything beyond a reasonable short period (e.g., 30 days) should be re-justified if allowed at all.

Commission Response

The commission agrees with AARP that the standard for a good cause exception should be high, and the commission intends to apply the standard accordingly. The commission declines to include specific maximum time limits in the rule as suggested by AARP. The justification for a good cause exception may often be fact specific and a compliance deadline must account for those specific factual circumstances.

OPUC requested a revision to ensure that specified consequences and penalties will be imposed by the commission, unless a good cause exception granted.

Commission Response

The commission declines to detail specific consequences and penalties for noncompliance under paragraph (c)(1). 16 TAC § 25.8 (relating to Classification System for Violations of Statutes, Rules, and Orders Applicable to Electric Service Providers) establishes a classification system for the assessment of administrative penalties. This assessment is fact-intensive and is therefore best made in response to an actual violation as part of an enforcement investigation by the commission.

Paragraph (d)(1), ERCOT Inspection of Generation Resources

This paragraph would require ERCOT to inspect generation resources.

Oncor Cities requested that the commission require the inspections be conducted on-site by qualified, full-time ERCOT inspectors or by inspectors employed by another qualified entity selected by the commission and ERCOT. Oncor Cities also requested that ERCOT present a plan for hiring and training inspectors. Finally, Oncor Cities requested that ERCOT establish a mandatory inspection schedule to which it must adhere.

Commission Response

The commission declines to adopt the changes proposed by Oncor Cities. The commission determines that ERCOT can suitably use its expertise and industry insights to determine

how best to schedule and conduct inspections of generation resources. ERCOT's plans to engage full-time inspection staff and supplemental outside contractors are best determined by ERCOT.

Oncor Cities expressed concern about ERCOT's ability to both conduct inspections and maintain focus on its other critical core functions.

Commission Response

Oncor Cities' concerns about ERCOT's other critical core functions are beyond the scope of this rulemaking project, which is focused on developing weather emergency preparation measures and reliability standards for generation resources and transmission facilities.

ERCOT Prioritization of Inspections Based on Risk Level

This paragraph would require ERCOT to prioritize its inspection schedule based on risk level.

TAEBA stated that the commission should define the term risk level and clarify whether ERCOT's pre-inspection risk level assessment of generators will be publicly available and how often ERCOT will be required to update its assessment to reflect measures taken by generators to enhance reliability. Enel similarly requested clarification of the risk level ERCOT will use.

Commission Response

The commission declines to define the term risk level. The rule enumerates several characteristics of risk to grid reliability upon which ERCOT may determine how to

effectively prioritize its inspections. Moreover, due to security concerns, ERCOT will not publicly post whether the loss of generating capacity at a particular generation resource presents a reliability risk.

As explained in the discussion of the definition of inspection in paragraph (b)(5) of the rule, the commission moves the provision that requires ERCOT to determine the number, extent, and content of inspections in consultation with the commission to this paragraph (d)(1) as well as paragraph (g)(1). To address the discussion in paragraph (b)(5) related to physical security of generation resources to be inspected, the commission revises the rule to require ERCOT to notify a generation entity of an upcoming inspection, ensure ERCOT's inspectors have access to the generation resource to be inspected, and permit a generation entity to escort ERCOT's inspectors while they are on site.

The commission also replaces "extreme weather conditions" with "weather emergency conditions" to make this requirement consistent with the overarching context of the requirements in paragraph (c)(1).

Paragraph (d)(2), ERCOT Inspection Report

The proposed paragraph would require an inspection report and require actions to be taken for deficiencies that are identified in the report.

TPPA requested that the inspection report be provided in writing so that a generation entity will have complete information regarding the results of the inspection.

Commission Response

The commission declines to adjust the rule to require that the inspection report be provided in writing because doing so would unnecessarily limit the manner in which an inspection assessment may be provided most efficiently to the generation entity. In some instances, it may be most effective for ERCOT to provide immediate feedback to the generation entity at the time of the inspection. In other instances, a more detailed, written report should be provided to the generation entity. Given the timeframe for the winter 2021-2022 inspections, the commission is unwilling to hinder ERCOT's ability to provide important timely feedback.

Proposed paragraph (d)(2) would also require ERCOT to provide a reasonable period of time to a generation entity to cure deficiencies identified in an inspection report before any enforcement investigation can be taken. TEC requested that the commission add cost as one of the specific factors that ERCOT would use to determine an appropriate cure period.

Commission Response

The commission disagrees with TEC's proposal and declines to add cost to the list of factors ERCOT must consider when determining an appropriate cure period. Both the rule and PURA require ERCOT to provide a reasonable time period for generation entities to resolve noted deficiencies, and the rule requires ERCOT to consider the complexity of weather emergency preparation measures when it determines an appropriate cure period. The cost

of a given measure is not necessarily correlated with the amount of time the solution may take to implement.

TPPA, TEC, TCPA, and Calpine each requested that the commission entitle a generation entity to an appeal of ERCOT's determination of noncompliance and to be able to dispute the time period specified by ERCOT to remedy the deficiencies. Calpine also intimated that, because the rule is new and its interpretation will likely evolve over the coming months, a generation entity should be allowed to dispute ERCOT's findings, especially because the commission is able to apply a $1 million per day enforcement penalty for noncompliance.

Commission Response

The commission declines to change the rule to allow a generation entity to appeal ERCOT's determination of deficiencies or the amount of time specified by ERCOT to remedy deficiencies. The rule requires ERCOT to communicate its determination of noncompliance directly to a generation entity, and a noncompliant generation entity will have a reasonable amount of time to cure the deficiencies. The commission does revise the rule provision to allow a generation entity the opportunity to request a different amount of time to remedy deficiencies. Any such request, however, must be supported by documentation that justifies the different amount of time requested to cure the deficiency. The commission also notes that, although PURA §35.0021(g) requires the commission to impose an administrative penalty on a generation entity that has not cured its noncompliance within a reasonable amount of time, the amount of the administrative penalty will be determined through the

commission's enforcement process subject to PURA §15.023, which provides an entity with the opportunity to dispute an adverse finding through a contested case.

TPPA suggested that, as an alternative to an appeal process, the commission could clarify that §25.503(f)(2)(c) could be cited by a generation entity if ERCOT required a remedy within an unreasonable amount of time.

Commission Response

Section 25.503(f)(2) applies only to ERCOT procedures and protocols. §25.55 is not an ERCOT procedure or protocol. Therefore, a generation entity will not be excused from compliance with this rule simply by citing to §25.503(f)(2). The commission notes, however, that a generation entity is entitled to assert good cause for noncompliance with portions of this rule under paragraph (c)(6). Should a generation entity conclude that compliance with paragraph (c)(1) would jeopardize public health and safety or create risk of bodily harm or damage to equipment, for example, the generation entity can assert good cause for noncompliance or submit a request for a good cause exception. Further, it is the commission, not ERCOT, that ultimately determines whether the cure period was reasonable for enforcement purposes.

Proposed subsection (d)(2) would also require the cure period to be based on several factors, including ERCOT's determination of the risk of the resource's noncompliance to system reliability. Calpine commented that there are no metrics by which ERCOT must consider the "reliability risk of the resource's noncompliance" when determining an appropriate cure period, and therefore recommended the deletion of the clause from the rule.

Commission Response

The commission declines to adopt Calpine's recommendation to delete the clause, "the reliability risk of the resource's noncompliance" from the rule. The rule's entire focus is on mitigating risks to the reliable operation of the ERCOT bulk power system during a weather emergency. ERCOT's experience operating the bulk power system enables it to determine what type of risk a generation resource's noncompliance would have on bulk power system reliability. Not considering the reliability risk caused by a generation resource's noncompliance with this rule would be to ignore a core component of SB 3. Moreover, the commission regularly takes reliability risk into account when assessing administrative penalties for violations of ERCOT Protocols and the commission's rules.

Subsection (e), Weather-Related Failures by a Generation Resource to Provide Service

Proposed subsection (e) would require a generation entity with a resource that experiences repeated or major weather-related forced interruptions of service to contract with an independent engineer to assess the entity's plans and preparations for weather events.

Calpine requested that the commission clarify the term "repeated" because it could refer to multiple occurrences of forced interruption of service in one season or to occurrences of forced interruptions of service over more than one season. Calpine recommended "repeated" should be understood to mean multiple occurrences in same season, yet then provided language that deleted the word "repeated" and replaced it with "multiple occurrences of the same failures in similar conditions over a period of three years."

Commission Response

The commission declines to revise the subsection as suggested by Calpine. The language "repeated or major weather-related forced interruptions of service" is taken directly from PURA §35.0021 and should be understood to apply to recurring failures at a generation resource that result in a resource trip, deration, or failure to start. The commission, at this time, declines to define over what period of time a recurring failure at a generation resource would constitute a repeated forced interruption of service.

TEC suggested that the commission expanded the scope of the rule by including the term "maintenance-related outages" as a type of repeated or major weather-related forced interruptions of service contemplated by the statute. TEC's concern centered around the fact that maintenance outages are not necessarily indicative of a need for additional commission oversight. TEC then proposed to strike the entire clause "including forced outages, derates, or maintenance-related outages" from the subsection. Similarly, Enel requested the commission clarify that a resource on an outage that is necessary according to its operating plan should not be classified as a "weather-related failure."

Commission Response

TEC's and Enel's proposed revisions are too broad. Maintenance-related outages are not *always* a signal that additional oversight by the commission is needed, because a generation resource operator may try to take advantage of small windows of time over several days to fix multiple problems to keep the generation resource online when it is needed. In addition, as noted by Enel, certain types of generation resources are required to stop operating under more severe weather conditions; for example, wind generators cannot safely operate when wind speeds exceed a certain threshold.

However, if a generation entity must take repeated maintenance level outages at a generation resource due to a failure to adequately prepare the generation resource for winter weather operations, the repeated maintenance-level outage *is* a signal to the commission that more oversight is required. If a generation resource is taking an outage for reasons beyond maintaining safe operating practices, additional commission oversight may be required. Moreover, TEC's exclusion of "forced outages" and "derates" suggests a desire to narrow the scope of the rule. Therefore, the commission revises the subsection by changing the word "including" to "such as" to demonstrate that forced outages, derates, and maintenance-level outages are examples of forced interruptions of service that may require a generation entity to engage an independent assessment of it generation resource.

Proposed subsection (e) would also require the engagement of an independent engineer who is not affiliated with the generation entity and has not participated in a previous assessment under this rule of one of the entity's resources.

Many commenters opposed excluding professional engineers who had participated in previous assessments of a resource experiencing repeated or major weather-related forced interruptions of service from conducting such an assessment again. TPPA, TEC, LCRA, Exelon, and Calpine each urged the commission to delete this prohibition because of a perceived limited pool of qualified and available engineers. LCRA further stated that the proposed restriction also imposed an unlawful restraint of trade.

Commission Response

The commission agrees with the commenters that the proposed limitation may result in unintentional difficulties to find qualified, independent engineers. However, it is important that generation entities use independent, unaffiliated engineers to conduct these inspections. Therefore, the commission revises the rule to prohibit the use of the same engineer more than once every five years, unless the generation entity can show that there are no other qualified, independent engineers reasonably available for engagement. Limiting the number of times an engineer can provide an independent assessment would not represent a restraint on free trade. The restriction imposed by subsection (e) is not for the benefit of one private party over another; rather, it is in the public's interest to ensure an engineer can assess generation resource readiness free from undue pressures of the generation entity and bias.

Proposed subsection (e) would also require ERCOT to adopt rules that implement this subsection. TAEBA, Exelon, and TCPA each requested clarification of the scope of and process ERCOT will use to adopt rules that implement this subsection. Specifically, Exelon wanted the scope of the ERCOT rule to consider whether it would be appropriate to require a wind generation entity to engage an independent consultant for repeated forced outages related to icing on turbine blades. Also, TCPA and TAEBA sought clarification of whether the rule adoption process will be open to the public or follow the traditional ERCOT market participant stakeholder procedures.

Commission Response

Currently, all ERCOT rules are adopted through an extensive stakeholder process, which provides multiple opportunities for market participants and other interested entities to provide ideas, submit feedback, and help shape market and reliability rules. The commission expects the rules required under subsection (e) to be adopted under the existing procedures or as amended by the ERCOT board of directors. In addition, all ERCOT protocols must be approved by the commission before becoming effective. The commission declines to prejudge the validity of including any specific type of component failure in the determination of whether repeated or major weather-related forced interruptions of service have occurred.

TPPA requested the commission clarify that the obligation of a generation entity to contract with a third-party qualified engineer to assess the entity's preparation measures, plans, procedures, and operations applies only after ERCOT adopts rules implementing this subsection (e).

Commission Response

The commission declines to delay the effective date of this rule provision, as requested by TPPA, until after ERCOT has adopted rules implementing subsection (e). PURA §35.0021(d) obligates the commission *by rule* to require a generation entity to contract with an independent person to assess the generation entity's preparations, plans, procedures, and operations. The commission expects ERCOT to adopt the rules necessary to implement this section in a timely fashion. However, the commission requires the assessment be conducted by an independent professional engineer, which should ensure that any assessments conducted prior to the adoption of rules by ERCOT are still meaningful.

TAEBA requested clarification of the conditions under which generation resources would be subject to additional inspections by ERCOT under subsection (e).

Commission Response

The commission declines to change the rule in response to this comment. Upon review of an independent engineer's generation resource assessment, ERCOT and the commission have discretion to consider the specific circumstances in determining whether the corrective actions taken by a generation entity to resolve the causes of a generation resource's repeated failures or major weather-related failures require additional scrutiny to ensure that the failures are unlikely to occur again under similar circumstances. Such additional inspections will adhere to the rules delineated in subsection (d).

Proposed subsection (e) would also require ERCOT to refer to the commission for investigation a generation entity that has violated the rule.

TEC and Texas Solar Power Association each requested clarification on the referral of violations of the rule. TEC requested the commission refine subsection (e) to clarify that ERCOT will only refer violations of this rule to the commission for enforcement of material deficiencies based on the independent engineer's assessment. TSPA requested clarity about what constitutes a reasonable period of time for a generation entity to cure a violation.

Commission Response

The commission declines to adopt TEC's recommendation to limit ERCOT referrals of violations only to material deficiencies. PURA §35.0021(c)(3) specifically requires ERCOT to report any violation of the rules adopted under this statute. Additionally, PURA §35.0021(g) requires the commission to impose an administrative penalty on a generation entity that violates these rules after giving the entity a reasonable opportunity to remedy the violation. The statutory requirements are clear, and the rule incorporates several opportunities for a generation entity to engage with ERCOT and the commission to correct a violation before enforcement action is taken by the commission.

The commission also declines to further define what constitutes a reasonable period of time to cure violations under this provision. Like with paragraph (d)(2), the commission retains its discretion to determine a compliance investigation process that allows ERCOT, the

generation entity, and the commission the opportunity to engage in meaningful discussions about how best to quickly resolve violations of the rule.

Subsection (f), Weather Emergency Preparedness Reliability Standards for a Transmission Service Provider

Proposed subsection (f) would establish weather preparation requirements that a TSP must take in advance of the 2021-2022 winter weather season. Calpine requested that if the commission does not adopt its suggestion to delete the words "phase one" included in the heading of subsection (c), then the heading of subsection (f) should be modified to include "phase one."

Commission Response

The commission deleted "phase one" from the heading of subsection (c). Accordingly, the commission declines to add "phase one" to the heading for subsection (f).

Oncor requested the commission extend the deadline to comply with the requirements of paragraphs (f)(1) and (f)(2) to December 15, 2021. Oncor stated that the December 1, 2021 deadline creates tight timing challenges to conduct training and complete inspections. Oncor suggested the extended deadline would enhance the expected benefits of these requirements.

Commission Response

The commission declines to extend the deadline imposed in paragraphs (f)(1) and (f)(2). TSPs incapable of completing the requirements are able to file a request for a good cause exception under paragraph (f)(2).

Paragraph (f)(1), Weather Emergency Preparation Measures

TNMP suggested adding the word "transmission" to clarify "its systems and facilities" in subsection (f)(1). Similarly, TEC suggested clarifying that the commission intended the systems and facilities identified through subsection (f)(1) to be those operated at transmission voltage. TEC requested the editing of subparagraphs (f)(1)(E), (f)(1)(F), and (f)(1)(H) to insert transmission voltage to describe certain components, systems, and equipment. Oncor requested clarification that the proposed rule applies to transmission-voltage switching stations and substations and not the distribution-voltage side of substations. AEP Companies requested clarification that winter weather emergency preparation measures enumerated throughout subsection (f)(1) apply only to high-voltage switching stations operating at or above 60 kilovolts.

Commission Response

The commission agrees with the commenters that the intent of subsection (f)(1) is to prepare components and equipment that operate at transmission level voltage. In paragraph (b)(1), the commission revises the definition of cold weather critical component applicable to TSPs to mean only transmission-voltage equipment located inside the fence surrounding a TSP's high-voltage switching station or substation. The commission finds additional revisions as recommended by the commenters above are not needed with this revised definition in place.

AEP Companies, TNMP, and Oncor stated that subparagraphs (A), (B), and (H) are not drawn directly from the 2011 FERC/NERC Report recommendations and should be deferred to phase two of the commission's weather preparedness rulemaking process where these provisions can be developed and discussed by stakeholders. CenterPoint stated that the requirements listed in subparagraphs (f)(1)(A), (f)(1)(B), (f)(1)(C), and (f)(1)(H) are not recommendations made in the 2011 FERC/NERC Report. Moreover, CenterPoint stated that these provisions are "too vague and ambitious for such quick implementation" and should be implemented in a future phase of the rulemaking.

Commission Response

The commission declines to remove the requested provisions from paragraph (f)(1), because these requirements are intended to prepare transmission systems to maintain service quality and reliability during the 2021-2022 winter weather season, in accordance with PURA §38.075. Exclusively addressing recommendations from the 2011 winter weather event would ignore lessons learned from the most recent 2021 winter weather event.

Sharyland commented that a "cold weather critical component" of a facility within a TSP's system that could freeze *and* likely result in a generation unit tripping, derating, or failing to start would include power transformers, high voltage circuit breakers, and certain specific elements within those components. Sharyland supported subparagraphs (f)(1)(A), (f)(1)(B), (f)(1)(C), and (f)(1)(H) assuming the inclusion of those components.

Commission Response

The commission revises the definition of cold weather critical component in paragraph (b)(1) rendering Sharyland's comments moot. The revised definition specifically addresses cold

weather critical components applicable to TSPs, in part, by removing references to generation resources.

Subparagraph (f)(1)(A), Preparation of Cold Weather Critical Components

TPPA and TNMP recommended the Commission clarify the definition of "sustained operation" in this provision to define the length of time a TSP is expected to ensure operation. LCRA TSC stated that the provision should be changed because it proposes to require a TSP to "ensure" a specific performance outcome, which is neither appropriate nor consistent. TEC proposed changes to reflect the preparation standard articulated in PURA §38.075 and to make explicit that actions must be reasonable and appropriate, in line with good utility practice.

Commission Response

The commission agrees with the commenters that the rule should impose a preparation standard on a TSP rather than a performance standard. The commission finds that the adjective "necessary" could be interpreted as requiring a certain level of performance and, thus, replaces it with "intended." To intend is to plan or to have something in mind as a purpose or goal. The use of "intended" should clarify that the rule is a preparation standard.

The commission requires a TSP to use its best efforts to meet the requirements specified throughout paragraph (f)(1). The commission changes "All actions" to "Best efforts" to reflect the preparation standard. The TSP must decide how best to comply with the requirements of this rule and further has the option to assert good cause for noncompliance.

The commission replaces "preparations" with the defined term "weather emergency preparation measures" to clarify its intent. Consistent with its discussion of the definition of weather emergency preparation measures with respect to proposed paragraph (b)(7), adopted paragraph (b)(8), the commission adds types of weather emergency preparation measures listed in proposed paragraph (b)(7) to subparagraph (f)(1)(A).

Finally, the commission declines to define the term "sustained operation" because the reliability standard in the rule provision pertains to the preparations taken in advance of operations, not the amount of time a transmission facility is capable of operating. Assuming the TSP can demonstrate it used best efforts intended to ensure sustained operation of the facility, the compliance standard should be met.

Subparagraph (f)(1)(C), Preventing Reoccurrence of Failures

The proposed subparagraph would require all actions necessary to address cold weather critical component failures that occurred under winter weather conditions in the period between November 30, 2020 and March 1, 2021.

Several commenters requested clarifications of subparagraph (f)(1)(C), claiming it is too broad. LCRA TSC stated that the proposed language "all actions necessary" transformed the rule into a performance standard, while CenterPoint recommended that the actions taken be "reasonable and prudent". CenterPoint also requested that the components be "owned and operated by the TSP." TPPA and TEC suggested that subparagraph (f)(1)(C) should be limited to failures that occurred directly due to winter weather, rather than one-off occurrences unrelated to cold weather operations. AEP Companies recommended that the provision apply only to circuit breaker or transformer failures that occurred due to freezing temperatures in the designated period. City of Houston stated that the provision should require a TSP to verify the need for the additional items; the estimated costs, expected benefits of the upgrades, and how this would have helped prevent any outages that occurred during Winter Storm Uri.

Commission Response

The commission agrees with the commenters that "all actions necessary" should be deleted and, consistent with its revision to subparagraph (c)(1)(C), the commission changes the phrase to "best efforts to." In addition, the commission agrees with commenters and revises subparagraph (c)(1)(C) to apply only to failures that occurred due to winter weather conditions between November 30, 2020 and March 1, 2021. However, the commission declines to limit the scope of the subparagraph to circuit breakers and transformers failures because other cold weather critical components during winter weather conditions are also cause for concern. The commission also declines to add "owned and operated by the TSP" as the commission has clarified the definition of cold weather critical component in paragraph (b)(1). The commission declines to require the verification requested City of Houston because a TSP is already required to prove the reasonableness of costs it seeks to recover in transmission rates.

Subparagraph (f)(1)(D), Training

Oncor Cities stated that the lack of standards contained in the subparagraph could leave the rule open to broad interpretation. TNMP proposed either replacing "winter weather preparation" with "load shed procedure training" or adding the new term to the subsection to more closely align with the 2011 FERC Winter Report. AEP Companies requested the commission not add any new training requirements in advance of the 2021-2022 winter weather season. In the alternative, AEP Companies stated that the training should focus on weather emergency preparation measures. CenterPoint recommended adding "including load shedding procedures" to the proposed language.

Commission Response

The commission revises subparagraph (f)(1)(D) to mirror revisions to subparagraph (c)(1)(D). The commission declines to adopt Oncor Cities' recommendation and notes the training programs must be flexible enough to meet facility-specific operational guidelines and weather preparations. The commission also declines to add a new term or change the rule to specify the training requirement should be focused on load shed procedures. There are many preparations TSPs will need to take to get ready for the upcoming winter weather season, and the commission declines to specify particular types of training requirements.

Subparagraph (f)(1)(E), SF6 Gas Breakers and Metering

TPPA requested the commission clarify that these requirements only apply to existing installations that use sulfur hexafluoride gas and should not be interpreted as an instruction that existing transmission breakers (or other equipment) that do not use sulfur hexafluoride gas be replaced with those that do. Oncor suggested that it would be more effective to inspect the items listed closer to the expected cold weather temperatures or other winter weather emergency.

Commission Response

As noted above, the commission changes subparagraph (f)(1)(A) by deleting "all actions" and instead requiring TSPs to use their "best efforts" to address the failures of cold weather critical components. A TSP must decide how best to comply with the requirements of this rule using its expertise and professional judgment; therefore, the commission declines to make the change recommended by TPPA. However, the commission replaces "extreme cold weather" with "winter weather emergency" to make this requirement consistent with the overarching requirements of paragraph (f)(1).

AEP Companies and CenterPoint recommended correcting a typographical error, replacing "by" with "and" to align with the 2011 FERC/NERC Report recommendation regarding SF6 gas in breakers, while Sharyland would prefer using "including."

Commission Response

The commission accepts AEP Companies and CenterPoint's recommendation and revises the rule accordingly. The commission declines to adopt Sharyland's recommendation in favor of the recommendation provided by AEP Companies and CenterPoint.

Subsection (f)(1)(F), Operability of Power Transformers

CenterPoint recommended adding auto transformers to the list of equipment a TSP must verify are operable in cold temperatures. CenterPoint also suggested deleting "extreme" as a description of the type of cold weather in which transformers should be prepared to operate.

Commission Response

The commission accepts CenterPoint's recommendation to include auto transformers in the rule language because they should be covered by this provision. The commission also replaces "extreme cold temperatures" with "winter weather emergencies" to clarify the circumstances for preparation.

Proposed Subparagraph (f)(1)(G), Determination of Ambient Temperatures

Sharyland was unclear about the scope of a TSP's equipment addressed by the provision and suggested that an overly broad interpretation of the "equipment" could lead to irrational outcomes. TEC recommended deleting this subpart because of the ambiguity of "equipment" and the difficulty of confirming ambient temperatures outside operations in actual weather conditions. TEC also noted overlap in reporting requirements with subparagraph (f)(1)(H) in that both require determination of temperatures and operating limitations. TPPA requested clarification as to whether the commission wanted an independent analysis of the specifications or if providing manufacturer specifications would suffice. AEP Companies proposed revisions to track more closely to the 2011 FERC/NERC Report recommendations.

Commission Response

The commission agrees with TEC that subparagraph (f)(1)(G) overlaps with subparagraph (f)(1)(H) and notes that the analysis required to document ambient temperatures may require greater effort than can be achieved in this rulemaking project timeline. Therefore, the commission will accept minimum design temperatures or minimum experienced operating temperatures, and other operating limitations as specified in subparagraph

25.55(f)(1)(H). The commission, therefore, deletes proposed subparagraph (f)(1)(G) but may reconsider it in a future rulemaking project.

Proposed Subparagraph (f)(1)(H), Design and Operating Limitations

Oncor Cities requested specific standards be included and was unsure if the determination of limitations is intended to be based on manufacturing specifications or based on the operations experience of each specific resource. Sharyland supported allowing the TSP to determine limitations, which would likely be based on various design specifications from the numerous transmission standards or from the design criteria from the original equipment manufacturers. LCRA TSC suggested that the provision be modified such that TSPs could provide minimum design temperature, minimum operating temperatures, or other operating limitations. AEP Companies, Oncor, TNMP, and CenterPoint proposed addressing design, operating, and other limitations in phase two of the rulemaking.

Commission Response

The commission accepts these commenters' recommendation for a transmission facility's operational limitations to be determined using operational history. Such operational history includes the February 2011 and 2021 winter weather events and is consistent with the legislative aim to take recent prior events into account. The commission, therefore, revises the rule accordingly.

Paragraph (f)(2), Winter Weather Readiness Report

TEC requested a revision to paragraph (f)(2) to use the words "pursuant to" when describing activities to be reported in the attestation under paragraph (f)(1) rather than the word "to complete" because, according to TEC, those activities should not be exhaustive, may not be completed by the time of inspection (if the measures are seasonal or temporary in nature), or may be subject to a good cause exception.

Commission Response

The commission declines to use the words "pursuant to" as suggested by TEC, because the word "complete" best describes the state of the best effort activities a TSP is required to meet under paragraph (f)(1). However, the commission revises subparagraph (f)(2)(B) to reflect in the attestation that a TSP may request a good cause exception under paragraph (f)(4).

AEP Companies requested that "all activities" be replaced with "weather emergency preparation measures."

Commission Response

The commission declines to adopt AEP Companies' recommendation, because the use of "all activities" emphasizes the comprehensive nature of the requirement. The commission notes that "all activities" should be interpreted within the overall context of the rule and that a TSP will use appropriate professional judgment when using its best efforts to implement weather emergency preparation measures.

AEP Companies requested the winter weather readiness report include a summary sheet that confirms the TSP has completed the necessary preparation measures and a description of measures taken by the TSP. AEP requested these changes to ease the TSP's reporting and submission of the required information given the short timeline afforded to TSPs for complying with the reporting requirements.

Commission Response

The commission declines to make the recommended changes to the TSPs' winter weather readiness report. Like the TSPs, ERCOT has a short timeline to gather and analyze the TSPs' winter weather readiness reports. ERCOT is capable of developing a comprehensive form that can be efficiently filled out by the TSPs. Finally, the form will be developed in consultation with commission staff, who will help ensure a balance of efficiency and completeness.

Paragraph (f)(3), ERCOT Compliance Report

AEP Companies requested deletion of the phrase "for all facilities subject to the requirements" as unnecessary.

Commission Response

The commission declines to make this change because the phrase emphasizes the requirement that the report be comprehensive. However, the commission revises this paragraph to make it consistent with revisions made to paragraph (c)(4).

Paragraph (f)(4), Good Cause Exception Request

CenterPoint requested a December 1, 2021 deadline for the submission of a request. CenterPoint also requested a revision to tie the detailed description and supporting documentation required by clause (f)(4)(A)(ii) to the requirement for which the good cause exception is requested rather than compliance more generally with paragraph (f)(1).

Commission Response

Consistent with CenterPoint's request and the revision to paragraph (c)(6), the commission revises the rule provision to impose a December 1, 2021 deadline for submission of a request for good cause exception. The commission also agrees with the requested revision to refer in clause (f)(4)(A)(ii) to the requirement for which the good cause exception is requested. In addition, the commission revises paragraph (f)(4) to make it consistent with the revisions to paragraph (c)(6) to provide for a streamlined process for good cause exceptions requests.

Subsection (g), Inspections for a Transmission Service Provider

Paragraph (g)(1), ERCOT Inspections

Proposed paragraph (g)(1) would require ERCOT to inspect the preparations of transmission systems and facilities ahead of the 2021-2022 winter weather season and requires ERCOT to prioritize inspections based on a risk assessment.

Oncor Cities recommended the commission require the inspections to be conducted on-site by qualified, full-time ERCOT inspectors or by inspectors employed by another qualified entity selected by the commission and ERCOT. Oncor Cities also requested ERCOT to present a plan for hiring and training inspectors. Finally, Oncor Cities proposed ERCOT establish a mandatory inspection schedule to which it must adhere.

Commission Response

The commission declines to adopt the changes proposed by Oncor Cities for the same reasons enumerated in its response to comments on paragraph (d)(1).

Oncor Cities expressed concern about ERCOT's ability to both conduct inspections and maintain focus on its other critical core functions.

Commission Response

Oncor Cities' concerns about ERCOT's other critical core functions are beyond the scope of this rulemaking project, which is focused on developing weather emergency preparation measures and reliability standards for generation resources and transmission facilities.

AEP companies requested ERCOT be required to provide sufficient notice to a TSP of a physical inspection of a substation to ensure the TSP can arrange safety escorts.

Commission Response

The commission revises the rule to require ERCOT to provide at least 48 hours' notice so that a TSP can make necessary safety and security arrangements. In order to remain consistent with the discussion in paragraph (b)(5) related to the physical security of facilities to be inspected by ERCOT, the commission also revises the rule to ensure ERCOT's

inspectors have access to the facility, and permit TSPs to escort ERCOT's inspectors while they are on site.

TPPA, TEC, and Oncor each recommended changes that would limit inspections to transmission voltage equipment owned and operated by a TSP. All three commenters noted that as proposed the rule could be interpreted to require inspection of a TSP's entire system, both inside and outside a substation fence line and including hundreds to thousands of miles of transmission line. TPPA specifically cited the extensive cost and logistical challenge of such a broad interpretation of the rule.

TAEBA's comments presumed ERCOT will inspect thousands of miles of transmission lines and TAEBA advised the commission that artificial intelligence and risk management software can aid in the identification of potential problems areas in the transmission system to help establish a prioritization scheme for the inspection schedule.

Commission Response

The commission adds clarifying language to paragraph (g)(1) instead of adding a new paragraph to limit the scope of ERCOT's inspections of a TSP's facilities within the fence surrounding a TSP's high-voltage switching station or substation.

Because the scope of the rule is being clarified to require inspection only of inside-station-fence facilities, TAEBA's comments are moot.

The commission replaces "extreme weather conditions" with "weather emergency conditions" to make this requirement consistent with the overarching context of subsection (f).

Subsection (g)(2), ERCOT Inspection Report

Proposed paragraph (g)(2) would require ERCOT to report on its inspections of transmission facilities, identify compliance deficiencies to the TSP, and provide a reasonable period of time for the TSP to remedy the deficiencies.

City of Houston commented that ERCOT should be required to identify all TSP weatherization projects that will not be completed prior to the beginning of the 2021-2022 winter weather season. City of Houston stated that this information would be helpful for the commission's report to the legislature on weather emergency preparedness, required under PURA §186.007.

Commission Response

The commission finds that additional reporting is not required to meet the requirements of PURA §38.075. The weather emergency preparedness report is not within the scope of this rule and is being considered under Project Number 51841. Additionally, under subsection (h), ERCOT must report to the commission any TSP that violates the rule.

As discussed in its comments on proposed paragraph (d)(2), TEC recommended ERCOT be explicitly required to consider both cost and time when determining a cure period for a TSP to remedy deficiencies identified in its inspections. CenterPoint requested ERCOT consider all relevant facts and circumstances when determining a cure period and provided a non-exhaustive list of examples.

Commission Response

The commission declines to add to the list of factors that ERCOT must consider when determining an appropriate cure period. Both the rule and PURA require ERCOT to provide a reasonable time period for an entity to remedy noted deficiencies, and the rule requires ERCOT to consider the complexity of the weather emergency preparation measures when it determines an appropriate cure period. The word "must" in this directive requires ERCOT to consider each of the factors described in the rule but does not indicate that these factors are the only factors ERCOT is allowed to consider when evaluating an appropriate cure period.

TPPA, TEC, and CenterPoint each requested the commission entitle a TSP to an appeal of ERCOT's determination of a cure period to remedy the identified deficiencies. The appeal process, according to these commenters, would ensure the TSP and commission have an opportunity to address the reasonableness of the cure period. Similarly, TNMP and CenterPoint recommended the commission allow ERCOT to consider any reasonable factors that may affect a TSP's ability to remedy a deficiency.

Commission Response

The rule requires ERCOT to communicate its determination of noncompliance directly to the TSP, and a noncompliant TSP will have a reasonable amount of time to cure the

deficiencies. The commission accepts TNMP's and CenterPoint's recommendations that consideration of the logistics of remedying a deficiency should be part of ERCOT's process to determine a reasonable cure period. The commission revises the rule provision to allow a TSP the opportunity to ask for a different amount of time to remedy deficiencies. Any such request must be supported by documentation to justify the additional time needed to cure a deficiency. However, the commission declines to add a specific appeals process consistent with paragraph (c)(4).

TPPA suggested that, as an alternative to an appeal process, the commission could clarify that §25.503(f)(2)(c) could be cited by a TSP if ERCOT required a remedy within an unreasonable amount of time.

Commission Response

For the same reasons cited in its response to TPPA's identical comment in subsection (d)(2), the commission determines that §25.503(f)(2) does not apply to instructions issued by ERCOT under this rule.

Proposed paragraph (g)(2) would require ERCOT to provide a report on its inspection of transmission facilities. TPPA requested the inspection report be provided in writing so that a TSP will have complete information regarding the results of the inspection.

Commission Response

The commission declines to change the rule to require the report be provided in writing because it would unnecessarily limit the manner in which ERCOT's inspection assessment may be provided most efficiently to the TSP. In some instances, it may be most effective for ERCOT to provide immediate feedback to the TSP at the time of the assessment. In other instances, a more detailed, written report should be provided to a TSP. Given the timeframe for the 2021-2022 winter weather season inspections, the commission is unwilling to hinder ERCOT's ability to provide important timely feedback.

Subsection (h), Weather-Related Failures by a Transmission Service Provider to Provide Service

Proposed subsection (h) would require a TSP with a facility that experiences repeated or major weather-related forced interruptions of service to contract with an independent engineer to assess the entity plans and preparations for weather events. The proposed subsection would also require ERCOT to adopt rules that specify the circumstances for which this requirement applies and specify the scope and contents of the assessment.

TNMP, AEP Companies, and CenterPoint each recommended the commission remove subsection (h) from the rule and reconsider it during a future rulemaking phase. TNMP stated that without more specific scoping and implementation rules adopted through the ERCOT stakeholder process, the subsection could require a TSP to contract with an independent engineer for any weather-related outage. AEP Companies also stated that more deliberation about the scope of the independent engineer reports is warranted. In the alternative, however, AEP Companies and CenterPoint recommended the commission clarify which rules would be subject to referral to the commission for enforcement. CenterPoint declared the subsection to be impractical and unreasonable because the rule did not provide any principles to guide ERCOT in exercising the requirement to adopt rules implementing this subsection.

Commission Response

Currently, all ERCOT rules are adopted through an extensive stakeholder process, which provides multiple opportunities for market participants and other interested parties to provide ideas, submit feedback, and help shape market and reliability rules. The commission expects the rules required under subsection (h) to be adopted under the existing procedures or as amended by the ERCOT board of directors. In addition, all ERCOT protocols must be approved by the commission before becoming effective. The commission declines to prejudge the validity of including any specific type of component failure in the determination of whether repeated or major weather-related forced interruptions of service have occurred.

Additionally, PURA §38.075(d) requires the commission to impose an administrative penalty on a TSP that violates these rules after giving the TSP a reasonable opportunity to remedy the violation. The statutory requirements are clear, and the rules incorporate several opportunities for a TSP to engage with ERCOT and the commission to correct a violation before any enforcement action is taken by the commission.

Finally, the commission recognizes that CenterPoint's comments were written with the understanding that its entire transmission system would be subject to ERCOT's inspection under subsection (g)(1). With the clarification that the requirements enumerated in

subsection (f) are limited to transmission-voltage facilities within a station controlled by a TSP, the compliance inspections under subsection (g) will be limited to the same facilities. Therefore, the commission finds that the requirements imposed under subsection (h) are neither impractical nor unreasonable.

However, the commission refines the subsection to eliminate terms more suited for the evaluation of generation resources.

TEC and LCRA TSC alternatively stated that subsection (h) should be eliminated from the rule because PURA §38.075 does not contain language that authorizes the commission to require the hiring of an independent engineer to assess facilities that have experienced repeated or major weather-related forced outages. In fact, LCRA TSC claimed that subsection (h) is contrary to the plain language of the statute.

Commission Response

The commission disagrees with TEC and LCRA TSC. Although PURA §38.075 does not contain the specific language requiring the engagement of independent engineers, PURA §38.005(f) does provide the commission with broad authority to compel TSPs to adhere to operational criteria established by ERCOT or adopted by the commission. Additionally, PURA §39.151(i) allows the commission to delegate authority to ERCOT to enforce operating standards within the ERCOT power region. The requirement to engage an independent consultant to provide a third-party review of preparations taken at a transmission-voltage station is focused on the core components of SB 3, namely mitigating

risks to the reliable operation of ERCOT's bulk power system during a weather emergency. When repeated failures of equipment inside a station affect reliable operations, it is within the public interest to require additional analyses that could provide meaningful remediation strategies. Accordingly, the commission declines to delete subsection (h) from the rule.

Proposed subsection (h) would require the engagement of an independent engineer who is not affiliated with the TSP and has not participated in a previous assessment under this rule of the TSP's system or facilities.

Many respondents opposed excluding professional engineers who had participated in previous assessments of the TSP's system or facilities experiencing repeated or major weather-related forced interruptions of service from conducting such an assessment again. TNMP, CenterPoint, and AEP Companies each stated that if the commission chooses to retain subsection (h), then it should delete this prohibition because of a perceived limited pool of qualified and available engineers.

Commission Response

The commission agrees with the commenters that the proposed limitation may result in unintentional difficulties to find qualified, independent engineers. However, it is important to the commission that TSPs use independent, unaffiliated engineers to conduct these inspections. Therefore, the commission revises the rule to prohibit use of the same engineer more than once every five years, unless the TSP can show there are no other qualified, independent engineers reasonably available for engagement.

Proposed subsection (h) would also require ERCOT to refer to the commission for enforcement a TSP that has violated the rule and failed to remedy the deficiency within a reasonable amount of time.

CenterPoint again requested deletion of subsection (h) because it does not explicitly detail each step to be taken in an enforcement proceeding under this rule. The City of Houston recommended the commission specify that penalties may be assessed against TSPs that fail to remedy deficiencies within the cure period.

Commission Response

As noted above, the commission finds that the inclusion of subsection (h) to be in the public interest. CenterPoint's assertion that there is no visibility or certainty in the enforcement process is not persuasive. Like the other TSPs operating in the ERCOT power region, CenterPoint has experience with enforcement investigations conducted by commission staff and should understand well the discretionary nature of the process to find resolution to violations of a statute or commission rule. The commission notes that PURA §38.075(d) requires the commission to impose an administrative penalty on a TSP that violates the rule and fails to remedy the deficiency in a reasonable amount of time. The commission takes this obligation seriously and retains subsection (h) accordingly.

The commission similarly declines to change subsection (h) to provide that administrative penalties may be assessed in an enforcement action. PURA §38.075 requires the commission

to assess administrative penalties in enforcement investigations brought under this rule. Changing the rule in the manner proposed would not provide any clarity as to how the statute is to be implemented by the commission.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this rule, the commission makes other minor modifications for the purpose of clarifying its intent.

The section is adopted under Public Utility Regulatory Act (PURA), Tex. Util. Code §14.001, which provides the commission the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by PURA that is necessary and convenient to the exercise of that power and jurisdiction; §14.002, which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; §35.0021, which requires the commission to adopt rules that require each provider of electric generation service in the ERCOT power region to implement measures to prepare the provider's generation assets to provide adequate electric generation service during a weather emergency; and §38.075, which requires the commission to adopt rules to require each electric cooperative, municipally owned utility, and transmission and distribution utility providing transmission service in the ERCOT power region to implement measures to prepare its facilities to maintain service quality and reliability during a weather emergency.

Cross reference to statutes: PURA §14.001, §14.002, §35.0021, and §38.075.

§25.55. Weather Emergency Preparedness.

(a) Application. This section applies to the Electric Reliability Council of Texas, Inc. (ERCOT) and to generation entities and transmission service providers (TSPs) in the ERCOT power region. A generation resource with an ERCOT-approved notice of suspension of operations for the 2021-2022 winter weather season is not required to be in compliance under this section until it is returned to service.

(b) Definitions. In this section, the following definitions apply unless the context indicates otherwise.

(1) **Cold weather critical component –** Any component that is susceptible to freezing or icing, the occurrence of which is likely to significantly hinder the ability of a resource or transmission system to function as intended and, for a generation entity, to lead to a trip, derate, or failure to start of a resource. For a TSP, cold weather critical component is limited to any transmission-voltage component within the fence surrounding a TSP's high-voltage switching station or substation.

(2) **Energy storage resource –** An energy storage system registered with ERCOT for the purpose of providing energy or ancillary services to the ERCOT grid and associated facilities controlled by the generation entity that are behind the system's point of interconnection, necessary for the operation of the system, and not part of a manufacturing process that is separate from the generation of electricity.

(3) **Generation entity** - An ERCOT-registered resource entity acting on behalf of an ERCOT-registered generation resource or energy storage resource.

(4) **Generation resource** – A generator capable of providing energy or ancillary services to the ERCOT grid and that is registered with ERCOT as a generation resource, as well as associated facilities controlled by the generation entity that are behind the generator's point of interconnection, necessary for the operation of the generator, and not part of a manufacturing process that is separate from the generation of electricity.

(5) **Inspection** –Activities that ERCOT engages in to determine whether a generation entity is in compliance with all or parts of paragraph (c)(1) of this section or whether a TSP is in compliance with all or parts of paragraph (f)(1) of this section. An inspection may include site visits; assessments of procedures; interviews; and review of information provided by a generation entity or TSP in response to a request by ERCOT, including review of evaluations conducted by the generation entity or TSP or its contractor.

(6) **Resource** - A generation resource or energy storage resource.

(7) **Weather emergency** – A situation resulting from weather conditions that produces significant risk for a TSP that firm load must be shed or a situation for which ERCOT provides advance notice to market participants involving weather-related risks to the ERCOT power region.

(8) **Weather emergency preparation measures** – Measures that a generation entity or TSP takes to support the function of a facility during a weather emergency.

(c) Weather emergency preparedness reliability standards for a generation entity.

(1) By December 1, 2021, a generation entity must complete the following winter weather emergency preparation measures for each resource under its control.

(A) Use best efforts to implement weather emergency preparation measures intended to ensure the sustained operation of all cold weather critical components during winter weather conditions, including weatherization, onsite fuel security, staffing plans, operational readiness, and structural preparations; secure sufficient chemicals, auxiliary fuels, and other materials; and personnel required to operate the resource;

(B) Install adequate wind breaks for resources susceptible to outages or derates caused by wind; enclose sensors for cold weather critical components; inspect thermal insulation for damage or degradation and repair damaged or degraded insulation; confirm the operability of instrument air moisture prevention systems; conduct maintenance of freeze protection components for all applicable equipment, including fuel delivery systems controlled by the generation entity, the failure of which could cause an outage or derate, and establish a schedule for testing of such freeze protection components on a monthly basis from November through March; and install monitoring systems for cold weather critical components, including circuitry providing freeze protection or preventing instrument air moisture;

(C) Use best efforts to address cold weather critical component failures that occurred because of winter weather conditions in the period between November 30, 2020, and March 1, 2021;

(D) Provide training on winter weather preparations and operations to relevant operational personnel; and

(E) Determine minimum design temperature or minimum experienced operating temperature, and other operating limitations based on temperature, precipitation, humidity, wind speed, and wind direction.

(2) By December 1, 2021, a generation entity must submit to the commission and ERCOT, on a form prescribed by ERCOT and developed in consultation with commission staff, a winter weather readiness report that:

(A) Describes all activities engaged in by the generation entity to complete the requirements of paragraph (1) of this subsection, including any assertions of good cause for noncompliance submitted under paragraph (6) of this subsection; and

(B) Includes a notarized attestation sworn to by the generation entity's highest-ranking representative, official, or officer with binding authority over the generation entity attesting to the completion of all activities described in paragraph (1) of this subsection, subject to any notice of or request for good cause exception submitted under paragraph (6) of this subsection, and to the accuracy and veracity of the information described in subparagraph (2)(A) of this paragraph.

(3) No later than December 10, 2021, ERCOT must file with the commission comprehensive checklist forms based on the requirements of paragraph (1) of this subsection that include checking systems and subsystems containing cold weather critical components. ERCOT must use a generation entity's winter weather

readiness report submitted under paragraph (2) of this subsection to adapt the checklist to the inspections of the generation entity's resources.

(4) No later than December 10, 2021, ERCOT must file with the commission a compliance report that addresses whether each generation entity has submitted the winter weather readiness report required by paragraph (2) of this subsection for each resource under the generation entity's control and whether the generation entity submitted an assertion of good cause for noncompliance under paragraph (6) of this subsection.

(5) A generation entity that timely submits to ERCOT the winter weather readiness report required by paragraph (2) of this subsection is exempt, for the 2021 calendar year, from the requirement in Section 3.21(3) of the ERCOT Protocols that requires a generation entity to submit the Declaration of Completion of Generation Resource Winter Weatherization Preparations no earlier than November 1 and no later than December 1 of each year.

(6) Good cause exception. A generation entity may submit by December 1, 2021 a notice to the commission asserting good cause for noncompliance with specific requirements listed in paragraph (1) of this subsection. The notice must be submitted as part of the generation entity's winter readiness report under paragraph (2) of this subsection.

(A) A generation entity's notice must include:

(i) A succinct explanation and supporting documentation of the generation entity's inability to comply with a specific requirement of paragraph (1) of this subsection;

(ii) A succinct description and supporting documentation of the generation entity's efforts that have been made to comply with the paragraph (1) of this subsection;

(iii) A plan, with supporting documentation, to comply with each specific requirement of paragraph (1) of this subsection for which good cause is being asserted, unless good cause exists not to comply with the requirement on a permanent basis. A plan under this subparagraph must include a proposed compliance deadline for each requirement of paragraph (1) of this subsection for which the good cause for noncompliance is being asserted and proposed filing deadlines for the generation entity to provide the commission with updates on its compliance status.

(B) Commission staff will work with ERCOT to expeditiously review notices asserting good cause for noncompliance. Commission staff may notify a generation entity that it disagrees with the generation entity's assertion of good cause and will file the notification in the project in which the winter weather readiness reports are filed. In addition, ERCOT may evaluate the generation entity's assertion of good cause as part of an inspection of the generation entity's resources.

(C) To preserve a good cause exception, a generation entity must submit to the commission a request for approval of a good cause exception within seven days of receipt of commission staff's notice of disagreement with the generation entity's assertion.

(D) The commission may order a generation entity to submit a request for approval of good cause exception.

(E) A request for approval of good cause exception must contain the following:

(i) A detailed explanation and supporting documentation of the inability of the generation entity to comply with a specific requirement of paragraph (1) of this subsection;

(ii) A detailed description and supporting documentation of the efforts that have been made to comply with paragraph (1) of this subsection;

(iii) A plan, with supporting documentation, to comply with each specific requirement of paragraph (1) of this subsection for which the good cause exception is being requested, unless the generation entity is seeking a permanent exception to the requirement. A plan under this subparagraph must include a proposed compliance deadline for each requirement of paragraph (1) of this subsection for which the good cause exception is being requested and proposed filing deadlines for the generation entity to provide the commission with updates on its compliance status.

(iv) Proof that notice of the request has been provided to ERCOT; and

(v) A notarized attestation sworn to by the generation entity's highest-ranking representative, official, or officer with binding authority over the generation entity attesting to the accuracy and veracity of the information in the request.

(F) ERCOT is a required party in a proceeding initiated under subparagraph (E) of this paragraph. ERCOT must make a recommendation to the commission on the request by the deadline set forth by the presiding officer in the proceeding.

(d) ERCOT inspection of generation resources.

(1) ERCOT-conducted inspections. ERCOT must conduct inspections of resources for the 2021–2022 winter weather season and must prioritize its inspection schedule based on risk level. ERCOT may prioritize inspections based on factors such as whether a generation resource is critical for electric grid reliability; has experienced a forced outage, forced derate, or failure to start related to weather emergency conditions; or has other vulnerabilities related to weather emergency conditions. ERCOT must determine, in consultation with commission staff, the number, extent, and content of inspections and may conduct inspections using both employees and contractors.

(A) ERCOT must provide each generation entity at least 48 hours' notice of an inspection unless otherwise agreed by the generation entity and ERCOT. Upon provision of the required notice, a generation entity must grant access to its facility to ERCOT and commission personnel, including an employee of a contractor designated by ERCOT or the commission to conduct, oversee, or observe the inspection.

(B) During the inspection, a generation entity must provide ERCOT and commission personnel access to any part of the facility upon request and must make the generation entity's staff available to answer questions. A generation entity may escort ERCOT and commission personnel at all times during an inspection. During the inspection, ERCOT or commission personnel may take photographs and video recordings of any part of the facility and may conduct interviews of facility personnel designated by the generation entity.

(2) ERCOT inspection report.

(A) ERCOT must provide a report on its inspection of a resource to the generation entity. The inspection report must address whether the generation entity has complied with the requirements in subsection (c)(1) of this section.

(B) If the generation entity has not complied with a requirement in subsection (c)(1) of this section, ERCOT must provide the generation entity a reasonable period to cure the identified deficiencies.

(i) The cure period determined by ERCOT must consider what weather emergency preparation measures the generation entity may be reasonably expected to have taken before ERCOT's inspection, the reliability risk of the resource's noncompliance, and the complexity of the measures needed to cure the deficiency.

(ii) The generation entity may request ERCOT determine a different amount of time to remedy the deficiencies. The request must be accompanied by documentation that supports the request for a different amount of time.

(iii) ERCOT, in consultation with commission staff, will determine the final cure period after considering a request for a different amount of time.

(C) ERCOT must report to commission staff any generation entity that does not remedy the deficiencies identified under subparagraph (A) of this paragraph within the cure period determined by ERCOT under clause (B)(iii) of this subparagraph.

(D) A generation entity reported by ERCOT to commission staff under subparagraph (C) of this paragraph will be subject to enforcement investigation under §22.246 (relating to Administrative Penalties) of this title.

(e) Weather-related failures by a generation entity to provide service. A generation entity with a resource that experiences repeated or major weather-related forced interruptions of service, such as forced outages, derates, or maintenance-related outages must contract with a qualified professional engineer to assess its weather emergency preparation measures, plans, procedures, and operations. The qualified professional engineer must not be an employee of the generation entity or its affiliate and must not have participated in previous assessments for the resource for at least five years, unless the generation entity can document that no other qualified professional engineers are reasonably available for engagement. The generation entity must submit the qualified professional engineer's assessment to the commission and ERCOT. ERCOT must adopt rules that specify the circumstances for which this requirement applies and specify the scope and contents of the assessment. A generation entity to which this subsection applies may be subject to additional inspections by ERCOT. ERCOT must refer to commission staff for investigation any generation entity that violates this rule.

(f) Weather emergency preparedness reliability standards for a TSP.

(1) By December 1, 2021, a TSP must complete the following winter weather preparations for its transmission system and facilities.

(A) Use best efforts to implement weather emergency preparation measures intended to ensure the sustained operation of all cold weather critical components during winter weather conditions, including weatherization, staffing plans, operational readiness, and structural preparations; secure sufficient chemicals, auxiliary fuels, and other materials; and personnel required to operate the transmission system and facilities;

(B) Confirm the ability of all systems and subsystems containing cold weather critical components required to ensure operation of each of the TSP's substations within the design and operating limitations addressed in subparagraph (1)(G) of this paragraph;

(C) Use best efforts to address cold weather critical component failures that occurred because of winter weather conditions in the period between November 30, 2020 and March 1, 2021;

(D) Provide training on winter weather preparations and operations to relevant operational personnel;

(E) Confirm that the sulfur hexafluoride gas in breakers and metering and other electrical equipment is at the correct pressure and temperature to operate safely during winter weather emergencies, and perform annual maintenance that tests sulfur hexafluoride breaker heaters and supporting circuitry to assure that they are functional;

(F) Confirm the operability of power transformers and auto transformers in winter weather emergencies by:

(i) Checking heaters in the control cabinets;

(ii) Verifying that main tank oil levels are appropriate for actual oil temperature;

(iii) Checking bushing oil levels; and

(iv) Checking the nitrogen pressure, if necessary.

(G) Determine minimum design temperature or minimum experienced operating temperature, and other operating limitations based on temperature, precipitation, humidity, wind speed, and wind direction for facilities containing cold weather critical components.

(2) By December 1, 2021, a TSP must submit to the commission and ERCOT, on a form prescribed by ERCOT and developed in consultation with commission staff, a winter weather readiness report that:

(A) Describes all activities engaged in by the TSP to complete the requirements of paragraph (1) of this subsection, including any assertions of good cause for noncompliance submitted under paragraph (4) of this subsection; and

(B) Includes a notarized attestation sworn to by the TSP's highest-ranking representative, official, or officer with binding authority over the TSP, attesting to the completion of all activities described in paragraph (1) of this subsection, subject to any notice of or request for good cause exception submitted under paragraph (4) of this subsection, and to the accuracy and veracity of the information described in subparagraph (2)(A) of this paragraph.

(3) No later than December 10, 2021, ERCOT must file with the commission a compliance report that addresses whether each TSP has submitted the winter weather readiness report required by paragraph (2) of this subsection for its transmission system and facilities and whether the TSP submitted an assertion of good cause for noncompliance under paragraph (4) of this subsection.

(4) Good cause exception. A TSP may submit to the commission by December 1, 2021 a notice asserting good cause for noncompliance with specific requirements listed in paragraph (1) of this subsection. The notice must be submitted as part of the TSP's winter weather readiness report under paragraph (2) of this subsection.

(A) A TSP's notice must include:

(i) A succinct explanation and supporting documentation of the TSP's inability to comply with a specific requirement of paragraph (1) of this subsection;

(ii) A succinct description and supporting documentation of the efforts that have been made to comply with the requirement; and

(iii) A plan, with supporting documentation, to comply with each specific requirement of paragraph (1) of this subsection for which good cause is being asserted, unless good cause exists not to comply with the requirement on a permanent basis. A plan under this subparagraph must include a proposed compliance deadline for each requirement of paragraph (1) of this subsection for which good cause for noncompliance is being asserted and proposed filing deadlines for the TSP to provide the commission with updates on the TSP's compliance status.

(B) Commission staff will work with ERCOT to expeditiously review notices asserting good cause for noncompliance. Commission staff may notify a TSP that it disagrees with the TSP's assertion of good cause and will file the notification in the project in which the winter weather readiness reports are filed. In addition, ERCOT may evaluate the TSP's assertion of good cause as part of an inspection of the transmission facility.

(C) To preserve a good cause exception, a TSP must submit to the commission a request for approval of a good cause exception within seven days of receipt of commission staff's notice of staff's disagreement with the TSP's assertion.

(D) The commission may order a TSP to submit a request for approval of good cause exception.

(E) A request for approval of good cause exception must contain the following:

(i) A detailed explanation and supporting documentation of the inability of the TSP to comply with the specific requirement of paragraph (1) of this subsection;

(ii) A detailed description and supporting documentation of the efforts that have been made to comply with paragraph (1) of this subsection;

(iii) A plan, with supporting documentation, to comply with each specific requirement of paragraph (1) of this subsection for which the good cause exception is being requested, unless the TSP is seeking a permanent exception to the requirement. A plan under this subparagraph must include a proposed compliance deadline for each requirement of paragraph (1) of this subsection for which the good cause exception is being requested and proposed filing deadlines for the TSP to provide the commission with updates on its compliance status.

(iv) Proof that notice of the request has been provided to ERCOT; and

(v) A notarized attestation sworn to by the TSP's highest-ranking representative, official, or officer with binding authority over the TSP attesting to the accuracy and veracity of the information in the request.

(F) ERCOT is a required party to the proceeding under subparagraph (E) of this paragraph. ERCOT must make a recommendation to the commission on the request by the deadline set forth by the presiding officer in the proceeding.

(g) **ERCOT inspections of transmission systems and facilities.**

(1) ERCOT-conducted inspections. ERCOT must conduct inspections of transmission facilities within the fence surrounding a TSP's high-voltage switching station or substation for the 2021–2022 winter weather season and must prioritize its inspection schedule based on risk level. ERCOT may prioritize inspections based on factors such as whether a transmission facility is critical for electric grid reliability; has experienced a forced outage or other failure related to weather emergency conditions; or has other vulnerabilities related to weather emergency conditions. ERCOT must determine, in consultation with commission staff, the number, extent, and content of inspections and may conduct inspections using both employees and contractors.

(A) ERCOT must provide each TSP at least 48 hours' notice of an inspection unless otherwise agreed by the TSP and ERCOT. Upon provision of the required notice, a TSP must grant access to its facility to ERCOT and commission personnel, including an employee of a contractor designated by ERCOT or the commission to conduct, oversee, or observe the inspection.

(B) During the inspection, a TSP must provide ERCOT and commission personnel access to any part of the facility upon request and must make the TSP's staff available to answer questions. A TSP may escort ERCOT and commission personnel at all times during an inspection. During the inspection, ERCOT and commission personnel may take photographs and video recordings of any part of the facility and may conduct interviews of facility personnel designated by the TSP.

(2) ERCOT inspection report.

(A) ERCOT must provide a report on its inspection of a transmission system or facility to the TSP. The inspection report must address whether the TSP has complied with the requirements in paragraph (f)(1) of this subsection.

(B) If the TSP has not complied with a requirement in subsection (f)(1) of this section, ERCOT must provide the TSP a reasonable period to cure the identified deficiencies.

(i) The cure period determined by ERCOT must consider what weather emergency preparation measures the TSP may be reasonably expected to have taken before ERCOT's inspection, the reliability risk of the TSP's noncompliance, and the complexity of the measures needed to cure the deficiency.

(ii) The TSP may request ERCOT determine a different amount of time to remedy the deficiencies. The request must be accompanied by documentation that supports the request for a different amount of time.

(iii) ERCOT, in consultation with commission staff, will determine the final cure period after considering a request for a different amount of time.

(C) ERCOT must report to commission staff any TSP that does not remedy the deficiencies identified under subparagraph (A) of this paragraph within the cure period determined by ERCOT under clause (B)(iii) of this subparagraph.

(D) A TSP reported by ERCOT to commission staff under subparagraph (C) of this paragraph will be subject to enforcement investigation under §22.246 (relating to Administrative Penalties) of this title.

(h) Weather-related failures by a TSP to provide service. A TSP with a transmission system or facility that experiences repeated or major weather-related forced interruptions of service must contract with a qualified professional engineer to assess its weather emergency preparation measures, plans, procedures, and operations. The qualified professional engineer must not be an employee of the TSP or its affiliate and must not have participated in previous assessments for this system or facility for at least five years, unless the TSP can document that no other qualified professional engineers are reasonably available for engagement. The TSP must submit the qualified professional engineer's assessment to the commission and ERCOT. ERCOT must adopt rules that specify the circumstances for which this requirement applies and specify the scope and contents of the assessment. A TSP to which this subsection applies may be subject to additional inspections by ERCOT. ERCOT must refer to commission staff for investigation any TSP that violates this rule.

This agency certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that §25.55, relating to weather emergency preparedness, is hereby adopted with changes to the text as proposed.

Signed at Austin, Texas the _____ day of October 2021.

PUBLIC UTILITY COMMISSION OF TEXAS

____

PETER LAKE, CHAIRMAN

____

WILL MCADAMS, COMMISSIONER

____

LORI COBOS, COMMISSIONER

____

JIMMY GLOTFELTY, COMMISSIONER

Appendix 5

SPECIAL EDITION

OCTOBER 2021

FISCAL NOTES

A REVIEW OF THE TEXAS ECONOMY FROM THE OFFICE OF **GLENN HEGAR**, TEXAS COMPTROLLER OF PUBLIC ACCOUNTS

Winter Storm Uri 2021

Photo courtesy of Texas Parks and Wildlife Department

A Message from the Comptroller

It's hard to believe that more than eight months have come and gone since Winter Storm Uri. The unprecedented snow and ice storm that pushed through Texas last February is still on our minds, especially for those who lost loved ones. We are dedicating the entirety of this month's issue to the storm for good reason — there is a lot to unpack. In this special edition of *Fiscal Notes*, we take an in-depth look at Winter Storm Uri's impacts, the immediate response and the legislative actions that followed.

Texas is the only state in the continental U.S. with its own electric power grid, serving 90 percent of its population. Independence from the national grid has its benefits and works well most of the time, but extreme weather events like Winter Storm Uri (and let's not forget the 2011 winter storm) have exposed a lack of proper planning and uneven weatherization procedures.

Winter Storm Uri knocked out power for nearly 70 percent of Texans and disrupted water utilities, leaving many Texans without heat or running water for extended periods in the frigid cold. It resulted in between $80 billion and $130 billion in financial losses to the state economy, and what's more, claimed at least 210 lives.

But this issue examines more than the physical and economic toll of the storm; just as important, it highlights the praiseworthy efforts by community partnerships to provide snow-boots-on-the-ground assistance to fellow Texans when they needed it most. You also can read about how the Texas Parks and Wildlife Department sprang into action to save defenseless wildlife. Many other agencies not covered in this issue assisted in noteworthy ways as well. Our agency eased restrictions on dyed diesel fuel to help ensure that enough fuel was available for disaster relief; we also extended due dates for state taxes and fees.

Last, but certainly not least, this issue boils down some of the Legislature's extensive and complex array of electric power reform bills signed by Gov. Abbott. At the forefront are bills that make big changes to the state's electric market and regulatory entities to reduce the risk of electricity disruptions from extreme weather events in the future. We pay special attention to Senate Bill 3, the largest and most wide-ranging bill passed in response to the storm.

I hope this issue finds you well, and please remember those who are still affected by the storm.

Glenn Hegar
Texas Comptroller of Public Accounts

Note: This report contains estimates and projections that are based on available information, assumptions and estimates as of the date of the forecasts upon which they are based. Assumptions involve judgments about future economic and market conditions and events that are difficult to predict. Actual results could differ from those predicted, and the difference could be material.

If you would like to receive paper copies of *Fiscal Notes*, contact us at **fiscal.notes@cpa.texas.gov**

PART I

The Economic Impact of the Storm

By Jess Donald

Winter Storm Uri, the severe weather event of February 2021, will long be etched into many Texans' minds. What might have been a rare opportunity for residents to experience significant snow accumulation turned catastrophic as power blackouts spanned most of the state from Feb.15-18. A survey conducted by the University of Houston (UH) Hobby School of Public Affairs in mid-March found that more than two out of three, or 69 percent, of Texans lost power at some point during Feb.14-20, and almost half, or about 49 percent, had disruptions in water service. The storm contributed to at least 210 deaths, and the Federal Reserve Bank of Dallas estimated the state's storm-related financial losses would range from $80 billion to $130 billion.

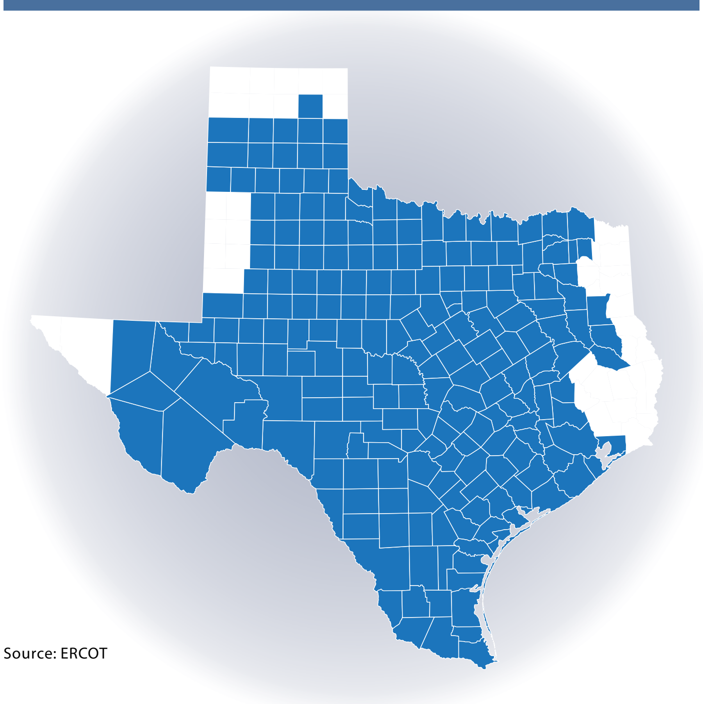
TEXAS ENERGY AND THE WINTER STORM

Like many other things in Texas, energy is big, and much of it also is independent. That independence extends to Texas' unique place as the only state in the continental United States that is not substantially interconnected with either the Eastern Interconnection or the Western Interconnection (**Exhibit 1**). The Public Utility Commission of Texas (PUC) regulates the Electric Reliability Council of Texas (ERCOT), which manages the electricity grid.

More than 26 million Texas customers, or nearly 90 percent of the state's population, depend on ERCOT for electricity services. ERCOT does not have its own grid infrastructure but instead relies on power generation companies, electricity providers/utilities (i.e., investor-owned and municipally owned providers, electric cooperatives and the river authorities), and transmission and distribution utilities that participate in the wholesale energy market.

EXHIBIT 1

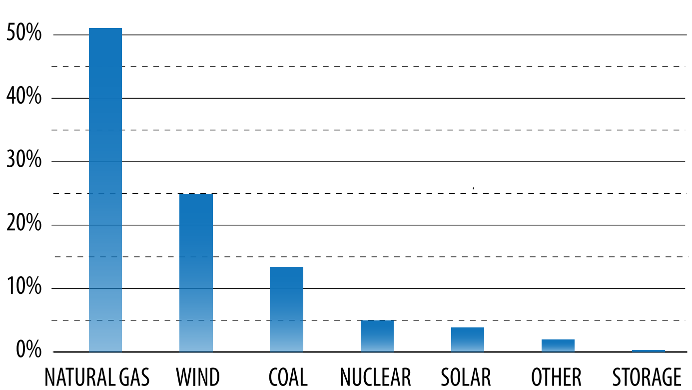
ERCOT GRID COVERAGE



Source: ERCOT

EXHIBIT 2

ERCOT GENERATING CAPACITY, FEBRUARY 2021



Source: ERCOT

Texas energy is generated from a variety of sources with the majority supplied by natural gas, wind and coal — 51 percent, 24.8 percent and 13.4 percent, respectively (**Exhibit 2**). More than 1,800 active market participants generate, move, buy, sell or use wholesale electricity, and ERCOT works with them to provide individual consumers with electricity. To ensure that the process runs smoothly, ERCOT produces seasonal planning reports to prepare for changes in weather and demand, as well as for potential emergencies based on historical data and planned outages for maintenance as well as other similar purposes.

Winter Storm Uri *far* exceeded the parameters of ERCOT's seasonal planning. According to the National Weather Service, freezing rain and drizzle coated North and Central Texas as the storm began rolling in on Feb. 11, 2021, causing up to one-half inch of ice accumulation in some locations. Snow later followed on Feb. 14-17, with 5 inches recorded at Dallas-Fort Worth (DFW) International Airport and 4.6 inches recorded at Waco

Regional Airport. DFW recorded 139 consecutive hours of at or below freezing temperatures, and the Waco airport recorded 205 consecutive hours.

Gov. Greg Abbott issued a state of emergency declaration on Feb. 12 due to the severity of the storm. On Feb. 13, some electricity generators began experiencing outages, and on Feb. 14, ERCOT issued a public plea for customers to reduce energy usage after power generation could not be increased to meet demand. As the grid continued to struggle to meet demand, controlled blackouts occurred, and on Feb. 15, ERCOT issued a declaration of emergency. According to a University of Texas at Austin (UT-Austin) Energy Report, the grid did not normalize until Feb. 19 and narrowly missed a *catastrophic* failure that potentially could have caused a total blackout throughout the state.

A PERFECT STORM OF CAUSATION

The UT-Austin report found that Uri, although not the most severe Texas winter storm on record, caused the most loss of electricity. The report also stated that rolling blackouts were intended to take stress off the power grid but turned into outages that — in some parts of the state — lasted several days. According to the report, multiple factors caused those extended blackouts, including that ERCOT underestimated peak demand by nearly 14 percent and weather forecasts misjudged the severity and timing of the storm.

While planned generator outages fell within the appropriate range listed in ERCOT's seasonal plan, the report found that outages were still high in number. Additionally, energy power generators failed on all fronts, including those powered by natural gas, wind and coal.

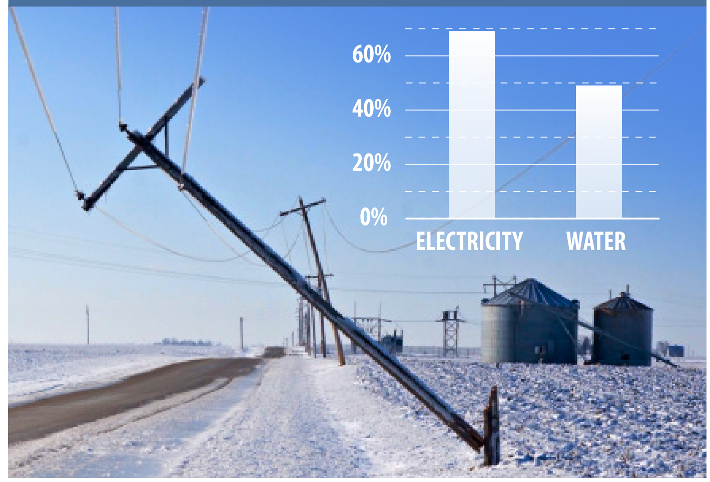
TEXAS LIVES AFFECTED

As mentioned, 210 people perished because of Winter Storm Uri. According to the Texas Department of State Health Services (DSHS), most fatalities can be attributed to hypothermia, vehicle crashes, carbon monoxide poisoning and chronic medical conditions complicated by the storm. (DSHS continues to monitor and update this figure as new information becomes available.)

Many residents found conditions within their homes unbearable, with indoor temperatures at or below freezing. Texas residents who were dependent on electrically powered medical equipment were especially vulnerable. According to the UH survey, of the 69 percent of Texans who lost power during the storm, their average disruption was 42 hours — 31 of those consecutive. And of the 49 percent of Texans who lost running water, their average disruption was 52 hours (**Exhibit 3**).

EXHIBIT 3

PERCENTAGE OF TEXANS WITHOUT ELECTRICITY OR RUNNING WATER, FEB. 14-20

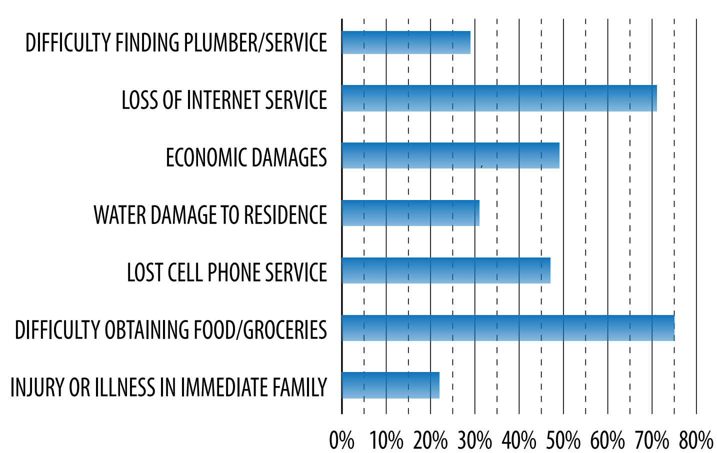


Source: University of Houston, Hobby School of Public Affairs, "The Winter Storm of 2021" survey

In addition to electricity and other utility disruptions, Texas residents experienced a host of negative effects from the winter storm (**Exhibit 4**). The UH survey found that three-quarters of respondents had difficulty procuring food and groceries. Meanwhile, 31 percent had water damage to their residences, and of those, only 18 percent believed insurance would likely cover the damage.

EXHIBIT 4

PERCENTAGE OF TEXANS EXPERIENCING OTHER NEGATIVE EFFECTS OF WINTER STORM URI



Source: University of Houston, Hobby School of Public Affairs, "The Winter Storm of 2021" survey

A recent study by the Texas Real Estate Center at Texas A&M University reported that, in 2019, 11 percent of homeowners in metropolitan areas had no homeowners insurance, compared with 26.6 percent of uninsured homeowners outside those areas. The center also found that low-income Texans were more likely to be uninsured, leaving them to pay for the entirety of their home repairs.

SUPPLY CHAIN DISRUPTIONS

Supply chains, which already were in turmoil because of the COVID-19 pandemic, suffered more disruption due to Winter Storm Uri. This setback included Texas chemical plants, which make up nearly 75 percent of U.S. chemical production and contribute to the manufacture of ingredients necessary for disinfectants, plastic bottles, fertilizer, pesticides and packaging. The freezing temperatures and blackouts damaged equipment in those plants, further slowing supply lines.

Chemical, plastic and rubber exports — accounting for almost 17 percent of Texas exports during the three months prior to the winter storm — saw their inflation-adjusted value decrease by more than 20 percent in February 2021. Additionally, supply chains stumbled because goods could not be transported by truck or rail in such dire weather conditions.

AGRICULTURAL LOSSES

According to an estimate from the Texas A&M AgriLife Extension Service (AgriLife Extension) in March, Texas agriculture experienced losses of more than $608 million from Winter Storm Uri. AgriLife Extension found that ranchers not only lost cattle, sheep, goats and poultry to the extreme cold, but much of their grazing grain was lost as well. The latter left ranchers with few options except to buy additional feed.

Some dairy operators were forced to dump milk due to transportation difficulties during the storm. And because the winter storm hit during birthing season, it led to the loss of many newborn calves and lambs. Overall, AgriLife Extension tallied economic losses to ranchers at nearly $228 million.

The same group estimated losses for citrus farmers of at least $230 million. Some Rio Grande Valley producers lost more than 60 percent of their crops. Citrus crops that did not survive the storm may take years to replace and begin producing fruit, causing an even greater economic impact. Vegetable crops also suffered, with devastating losses totaling nearly $150 million. The most significant impact to vegetable farmers was to onions, leafy greens and watermelons. Agricultural production disruption and the related increased cost of livestock feed contributed to some higher costs at grocery stores as well; with yields down, prices went up.

Due to the complexity of the Texas grid system and variety of consumer options, the exact impact on Texas energy customers is still difficult to discern.

URI'S ECONOMIC TOLL

Although Winter Storm Uri's devastation continues to be tallied, early estimates of the storm's economic toll, as mentioned, range from $80 billion to $130 billion — the result of power loss, physical infrastructure damage and forgone economic opportunities. Due to the complexity of the Texas grid system and variety of consumer options, the exact impact on Texas energy customers is still difficult to discern. What we do know is that all major sources of energy in the state experienced failures, along with the power grid managed by ERCOT.

UT-Austin professor of energy resources, Dr. Joshua Rhodes, who also works with the educational Webber Energy Group, says blackouts were the "last line of defense." Had the grid continued to decline causing a catastrophic failure, "Texas manufacturing would likely have come to a halt," he says, "and its ripple effects would've affected the state's GDP in a major way."

Thankfully, that scenario did not occur, but in February 2021, Winter Storm Uri *did* help to illustrate the interconnectedness of the Texas economy and provide an opportunity to better mitigate the effects of future storms. **FN**

*Learn about actions our state agency took in response to the winter storm by visiting "Winter Storms, February 2021" at **Comptroller.Texas.Gov/disaster-relief/**.*

PART II

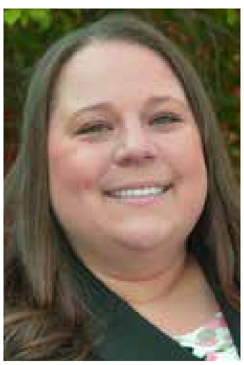
Texans Respond During and After the Storm

By Leticia Torres

Texans have a history of showing up for their neighbors — and the winter storm of February 2021 was no exception. For the millions who endured power outages and no running water amid freezing temperatures, the need for essentials became a dire issue. Many turned to family and friends for help. Others sought assistance and relief from local community organizations and businesses. Those included the American Red Cross, food banks and even a South Texas-based grocery store chain that worked together, and in some cases, partnered to provide services.

COMMUNITY PARTNERSHIPS

"The greatest needs for residents in North Texas during and after the February winter storm were warming stations, information, food, water and health and mental health support," says Krystal Smith, regional communications director with the American Red Cross of the North Texas Region (North Texas ARC). The region serves about 9 million people in 121 counties through the work of six local chapters.



KRYSTAL SMITH
AMERICAN RED CROSS OF THE NORTH TEXAS REGION

Smith says each service was provided through community efforts that involved more than 300 trained Red Cross staff working alongside community and government partners. Prior to the storm, she says the Red Cross already was working closely with local jurisdictions across the state to offer support as they opened warming centers for those seeking refuge from severe weather conditions.

"This included proactively providing more than 500 cots and 1,000 blankets in the North Texas area alone before the storm hit," Smith says.

As the storm progressed across the state, these partnerships continued providing more than 140,000 meals and snacks and distributing more than 12,000 supplies, such as comfort kits containing hygiene essentials. In addition, the partnerships provided more than 1,600 professionals to assist with physical, emotional and spiritual care needs.

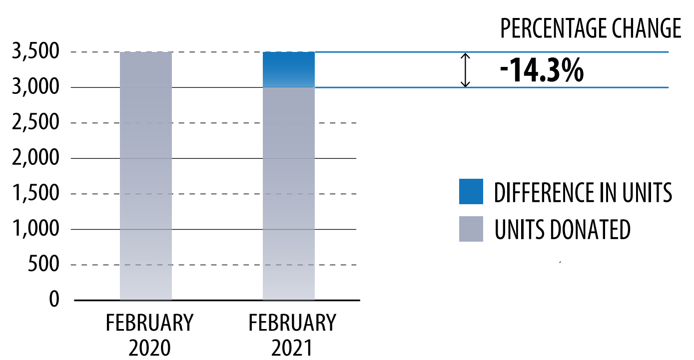
Compounding efforts to provide basic food and shelter, says Smith, was the demand for blood donations (**Exhibit 1**) — all of which created a sense of greater urgency as the ice storm continued unabated. Because of inclement weather, North Texas ARC cancelled 46 blood drives. Across the state, those cancellations resulted in a big loss of donated blood.

Another issue North Texas ARC faced was an increase in calls requesting assistance for home fires. "The number of home and apartment fires significantly increased as people attempted to warm their homes," she says. "In February 2021, the North Texas Red Cross responded to 285 fires and assisted over 1,400 people — more than double the previous year."

Because of inclement weather, North Texas ARC cancelled 46 blood drives. Across the state, those cancellations resulted in a big loss of donated blood.

EXHIBIT 1

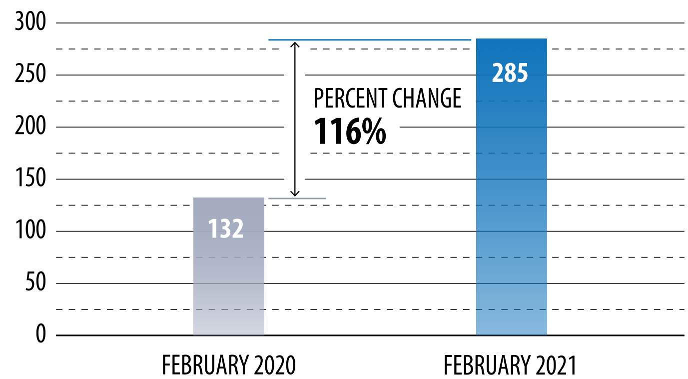
BLOOD DRIVE DONATIONS IN TEXAS, FEBRUARY 2020, 2021*



*Figures are approximate.
Source: American Red Cross of North Texas

EXHIBIT 2

RESPONSES TO HOUSE FIRES BY NORTH TEXAS ARC



Source: American Red Cross of North Texas

Exhibit 2 shows the year-over-year increase in response to home fires by North Texas ARC. On Feb. 19, the National Fire Protection Association reported that the winter storm and resulting power outages were contributing to home fires and carbon monoxide poisoning as residents used unsafe methods to warm homes, keep lights on and prevent pipes from bursting.

THE SEARCH FOR FOOD

Farther east, the circumstances were just as dire. Unsafe road conditions and flooding in the offices of the East Texas Food Bank in Tyler posed a big problem.

"Since we cover 26 East Texas counties, we had to completely shut down our operations for a week because staff could not safely travel to work and the road conditions were hazardous for our drivers," says food bank CEO Dennis Cullinane.

But even with the organization's warehouse shut down, he says that its leadership was able to immediately assist the community by distributing emergency supplies.

"Though we do not have a specific count on how many people needed help, our food distribution hit record levels immediately after the storm and persisted until our partner agencies were able to be restocked," Cullinane says.

DENNIS CULLINANE

EAST TEXAS FOOD BANK

Meanwhile, at the San Antonio Food Bank in South Texas, a similar scenario was underway.

"We generally are responding to a natural disaster in a different region, but this one was right on top of us," says Eric Cooper, president and CEO of the San Antonio Food Bank. "It kept us off the roads and without distribution nodes for emergency food and meals."

ERIC COOPER

SAN ANTONIO FOOD BANK

It all worked out with a little help, Cooper says. "We had to lean on the local police department to transport food and meals to those [who were] stranded."

Cooper added that many in need were not the food bank's usual clientele. "We also were providing meals for more well-off households who had no power and nowhere to go but hotels. And the hotels had no ability to get the food or water, so we handled that as well."

Still hundreds of others lined up at the San Antonio Food Bank's headquarters seeking the essentials that they couldn't find at area grocery stores.

Photo courtesy of San Antonio Food Bank

On Feb. 19, several days into the storm, Craig Boyan, H-E-B president, posted a video on the grocer's Facebook page to address some of the issues the company was facing.

"Like many across the state, our stores, our manufacturing plants, our warehouses, our partners and drivers have been seriously affected by this storm," he says. "But know we are doing all we can to select and load trucks, to ship products safely to stores and take good care of you."

Among business responses, the privately held supermarket chain, based out of San Antonio, made national headlines for its response. Some even referred to the company as the model of emergency preparedness, and Texans couldn't have been more appreciative as they took to social media to let everyone know.

H-E-B's Facebook comments

THE COVID EFFECT

Then there was COVID. On the upside, Cullinane says the East Texas Food Bank's pivot to working remotely during the pandemic helped.

"Though our facility was inaccessible and closed, many staff members had been given laptops and were able to work from home without losing much effectiveness," he says. "I was able to continue our strategic planning and communicate with our local emergency response officials to redirect some truckloads of food from the food bank to warming sites."

For the San Antonio Food Bank, the downside was the disruption of its distribution chain.

"We had more than 500 food pantry partners helping in the distribution of food across 16 counties," says Cooper. "COVID closed more than 90 percent of those pantries. The food bank was left without a normal distribution channel for 40 percent of its food."

He adds that for many months there had been no food to pick up at grocery stores or restaurants, which had been normal sources before the pandemic.

"Additionally, food manufacturers were struggling to fulfill orders and did not have overages, again leaving less for food banks across the U.S.," Cooper says. "Only recently has this gotten better."

Photo courtesy of San Antonio Food Bank

Hundreds of people impacted by the storm lined up for San Antonio Food Bank distributions.

Photos courtesy of Texas Parks and Wildlife Department

IMPACT ON WILDLIFE

Humans weren't the only ones hit hard by this historic storm. The Texas Parks and Wildlife Department (TPWD), in an online Texas Master Naturalist seminar in April, reported that hundreds of thousands of animals perished as the result of the severity of the storm. They included birds, bats, exotic deer, sea turtles and fish.

Dakus Geeslin, with the TPWD Coastal Fisheries Science and Policy Branch, says the fish kill alone was the largest freeze-related event since the 1980s.

"The geographic extent was the entire coast," he says. "We saw freezing temperatures all the way from Port Arthur near the Louisiana border … to Brownsville near the Rio Grande."

TPWD estimates approximately 3.8 million fish succumbed to the freeze event. In that same online seminar, Tony Reisinger, Cameron County Marine Extension Agent, said about 13,000 cold-stunned sea turtles were reported in Texas. According to fishery experts at the National Oceanic and Atmospheric Administration (NOAA), *cold-stunning* is a condition in which sea turtles become very weak and inactive from exposure to cold temperatures, usually when water temperatures drop below 50 degrees Fahrenheit.

"We had many working on retrieving these turtles that were cold-stunned — Texas Parks and Wildlife, fisheries biologists, law enforcement agents and many volunteers," Reisinger says. "We even had children helping transport sea turtles."

Cold-stunning is a condition in which sea turtles become very weak and inactive from exposure to cold temperatures, usually when water temperatures drop below 50 degrees Fahrenheit.

Photo courtesy of Texas Parks and Wildlife Department

Photo courtesy of the East Texas American Red Cross

PREPARING FOR ANOTHER STORM

Months after the winter storm, many Texans continue to deal with the damage it left behind. And many caught in Winter Storm Uri's harsh conditions have been thinking about what they can do to prepare for another storm. Smith of North Texas ARC is thinking about that, too. "The Red Cross plans to continue working closely with government and community partners to find the best ways to efficiently provide services to those who need it most."

Although unforeseen circumstances can disrupt even the best-made emergency plans, community organizations are rededicating themselves to prepare for the next big event. The San Antonio Food Bank is looking at scenario planning with local emergency management offices. The East Texas Food Bank will be installing an emergency generator for backup power. And the Red Cross is focused on educating the public on how to prepare for weather emergencies.

"Most importantly, we want to encourage everyone to build an emergency kit, make an emergency plan and stay informed," Smith says. "Ideally, each person's emergency kit should be equipped with supplies for three days, if evacuating, and two weeks, if staying at home."

Although unforeseen circumstances can disrupt even the best-made emergency plans, community organizations are rededicating themselves to prepare for the next big event.

Detailed emergency preparedness information is available on the American Red Cross' website and is organized by the types of emergencies and natural disasters that potentially could affect each region. **FN**

*Each year, the state of Texas offers a sales tax holiday for emergency preparation supplies that includes fuel containers, flashlights and certain portable generators. A complete list of items that may be purchased tax-free is available at **Comptroller.Texas.Gov/taxes/publications/98-1017.php**. The next sales tax holiday for emergency supplies is April 23-25, 2022.*

PART III

The 87th Legislature Takes on Electricity Reform

By Spencer Grubbs

Reforming Texas' electric power sector was not on the agenda when the 87th Legislature convened in January 2021. That changed in late February after Winter Storm Uri exposed critical weaknesses in the state's power grid and its regulatory framework. Fortunately, ample time remained for Texas lawmakers to switch gears and pass bills in response to the storm's devastating impact on the state. This article highlights changes to the state's electric power industry in key bills passed by the 87th Legislature and signed by Gov. Greg Abbott.

CHANGES TO REGULATORY ENTITIES

Senate Bill (SB) 2 overhauls the governance structure of the Electric Reliability Council of Texas (ERCOT), the independent system operator that manages the flow of electricity for most of the state's power needs. Prior to this measure, ERCOT was governed by a board of directors with 16 members — eight members representing different electric industry segments; three "ex officio" members (who served on the board as a result of other official positions they held); and five members unaffiliated with any electric industry segments.

SB 2 reduces the number of ERCOT board members to 11 and requires that eight of those members be selected by a newly established three-member board selection committee appointed by the Texas governor, lieutenant governor and House speaker. The bill requires the eight board members selected by the committee to have executive-level experience in certain fields.

With this bill, all ERCOT board members must be residents of Texas. At the time of the winter storm, five of the 16 ERCOT board members did not reside in Texas.

Another important provision of the bill strengthens oversight of ERCOT by requiring that any rules adopted by or enforcement actions taken by ERCOT be *approved* by the Public Utility Commission of Texas (PUC). At the time of the storm, ERCOT rules and enforcement actions were subject only to oversight and review by the PUC.

Likewise, SB 2154 makes changes to the governance structure of the PUC. For example, the bill increases the number of PUC commissioners from three to five and requires commissioners to reside in Texas. **Exhibit 1** shows bills related to ERCOT and the PUC during the 87th Legislature's regular session.

The bill requires the eight board members selected by the committee to have executive-level experience in certain fields.

EXHIBIT 1

LEGISLATION RELATED TO ERCOT AND THE PUC

BILL	DESCRIPTION	EFFECTIVE DATE
SB 2	Relating to the governance of the Public Utility Commission of Texas, the Office of Public Utility Counsel and an independent organization certified to manage a power region	6/8/2021
SB 3	Relating to preparing for, preventing and responding to weather emergencies and power outages; increasing the amount of administrative and civil penalties	6/8/2021
SB 2154	Relating to the membership of the Public Utility Commission of Texas	6/18/2021
HB 2586	Relating to an annual audit of the independent organization certified for the ERCOT power region	9/1/2021

Note: This does not represent an exhaustive list.
Source: Texas Legislature Online

THE OMNIBUS BILL

SB 3, the 87th Legislature's omnibus storm response legislation, consolidates several bills that did not pass on their own, such as House Bill (HB) 12, and enacts a range of reforms to Texas' electric power industry. This article covers a select few of the bill's most salient provisions.

POWER OUTAGE ALERT SYSTEM

Under SB 3, the Texas Department of Public Safety (DPS), in coordination with the PUC and certain other state agencies, is required to develop and implement a new statewide alert system activated when the PUC or ERCOT determine the power supply in Texas is potentially inadequate to meet demand. The bill requires DPS to send an alert to designated media outlets, such as radio and TV stations, informing electricity customers that they may experience a power outage.

TEXAS ENERGY RELIABILITY COUNCIL

SB 3 further establishes in law a 25-member council to supplement regulation of the state's electric power markets, called the Texas Energy Reliability Council (TERC). At the time of the winter storm, TERC was a small, informal group. The bill requires TERC "to (1) ensure that the energy and electric industries in [Texas] meet high priority human needs and address critical infrastructure concerns and (2) enhance coordination and communication in the energy and electric industries in this state."

Before each legislative session, TERC will submit a report to the Legislature about the status of Texas' electricity supply chain.

TEXAS ELECTRICITY SUPPLY CHAIN SECURITY AND MAPPING COMMITTEE

A new five-member committee under SB 3 will identify critical infrastructure sources in Texas and map the state's electricity supply chain, which includes all natural gas facilities and practices required for electric generation facilities to maintain service for Texans. The supply chain map — slated to be updated by the committee at least once a year — will serve as a tool for state leaders to prioritize electricity service needs statewide during extreme weather events like Winter Storm Uri. The committee also is responsible for enhancing lines of communication among the PUC, ERCOT and critical infrastructure sources during those events.

WEATHER EMERGENCY PREPAREDNESS

SB 3 also requires certain energy facilities in Texas to weatherize (i.e., make the preparations necessary to maintain electric service during extreme weather conditions, including severe winter storms). Facilities directed to weatherize include electric generation facilities, transmission providers, certain natural gas facilities and pipelines and water utilities.

The bill requires ERCOT to inspect those facilities for compliance and report continuing violations to the PUC. To enforce the new weatherization requirements, certain regulators are authorized to levy fines ranging from $5,000 per violation per day to $1 million per violation per day.

SB 3 gives certain state agencies rulemaking authority, notably the PUC, meaning the bill's implementation will depend on the adopted rules. The PUC, for example, must develop new rules that specify weatherization requirements for energy facilities, as well as rules that establish a classification system for violations.

CRITICAL INFRASTRUCTURE

CRITICAL INFRASTRUCTURE is any physical or cyber asset, system or network unequivocally necessary for society and the economy to function *and* whose major disruption could have disastrous effects on national security, public health and economic growth. Electric power generators, such as utility providers, comprise only one sector of critical infrastructure in the U.S. There are 15 other sectors:

- **Chemical**
- **Communications**
- **Dams**
- **Emergency services**
- **Financial services**
- **Government facilities**
- **Information technology**
- **Transportation systems**
- **Commercial facilities**
- **Critical manufacturing**
- **Defense industrial base**
- **Food and agriculture**
- **Health care and public health**
- **Nuclear reactors, materials and waste**
- **Water and wastewater systems**

Source: Cybersecurity & Infrastructure Security Agency

Photo courtesy of TXDOT

CHANGES TO ELECTRIC MARKET STRUCTURE

The 87th Legislature modified the structure of the state's electric market, including electricity pricing (**Exhibit 2**). One of the Legislature's priority bills — HB 16 — prohibits retail electric providers in Texas from selling "wholesale indexed" service plans to residential customers. Electricity pricing under those plans is directly tied to the wholesale electricity spot price on the power grid, which can fluctuate wildly during extreme weather events and leave customers subject to sudden price spikes. That scenario occurred and was reported widely during Winter Storm Uri when the wholesale electricity price maxed out at $9,000 per megawatt hour and saddled some customers with thousands of dollars in electricity bills.

EXHIBIT 2

LEGISLATION RELATED TO ELECTRIC MARKET*

BILL	DESCRIPTION	EFFECTIVE DATE
SB 1281	Relating to a reliability assessment of the ERCOT power grid and certificates of public convenience and necessity for certain transmission projects	9/1/2021
HB 16	Relating to the regulation of certain retail electric products	9/1/2021

Note: This does not represent an exhaustive list.
Source: Texas Legislature Online
*SB 3 (Exhibit 1) includes legislation related to the electric market as well.

ADDRESSING THE COSTS

The 87th Legislature also grappled with the financial fallout from Winter Storm Uri that resulted from several electric market participants defaulting on payments to ERCOT, as well as disruptions in the natural gas market that inflated prices for gas utilities and gas-fired electric generators. **Exhibit 3** shows legislation related to storm costs that was passed by the 87th Legislature.

Among the bills, SB 1580 enables the state's electric cooperatives (not-for-profit organizations owned by their customers) to use a financing tool called *securitization* to recoup "extraordinary costs and expenses" resulting from the winter storm. Securitization is the practice of issuing low-interest bonds funded by small fees charged to customers over an extended period and is employed as an alternative to passing on the costs to customers all at once.

HB 1520, likewise, enables gas utilities to use securitization to recoup extraordinary costs incurred due to the winter storm. And HB 4492, another related storm bill, requires the Comptroller's office to invest up to $800 million of the Economic Stabilization Fund in bonds issued by the ERCOT. LBB fiscal note analysis states, "The bill enables ERCOT to issue debt obligations to finance substantial balances owed by wholesale market participants."

EXHIBIT 3

LEGISLATION RELATED TO STORM COSTS

BILL	DESCRIPTION	EFFECTIVE DATE
SB 1580	Relating to the use of securitization by electric cooperatives to address certain weather-related extraordinary costs and expenses and to the duty of electric utility market participants to pay certain amounts owed	6/18/2021
HB 1510	Relating to the response and resilience of certain electricity service providers to major weather-related events or other natural disasters; granting authority to issue bonds	6/1/2021
HB 1520	Relating to certain extraordinary costs incurred by certain gas utilities relating to Winter Storm Uri and a study of measures to mitigate similar future costs; providing authority to issue bonds and impose fees and assessments	6/16/2021
HB 4492	Relating to financing certain costs associated with electric markets; granting authority to issue bonds; authorizing fees	6/16/2021

Note: This does not represent an exhaustive list.
Source: Texas Legislature Online

CONCLUSION

Texas lawmakers were swift to respond to the aftermath of Winter Storm Uri. By the regular legislative session's end in May 2021, they had passed laws that overhauled the structure of electric power regulatory entities, made changes to the electric market itself to reduce the risk of future disruptions and tempered the financial fallout. It's too early to draw conclusions about the effects of those changes. **FN**

Related to utility management, did you know the Comptroller's State Energy Conservation Office (SECO) reports the electricity, natural gas, water and transportation fuel consumption of state agencies and state universities? Read about it at ***Comptroller.Texas.Gov/programs/seco/reporting/umr/****.*

Winter Storm Uri

If you were living in Dallas, Houston, San Antonio or another place in Texas during Winter Storm Uri, you likely experienced an unforgettable weather event, as these photos attest. Yet despite the state's deep freeze, many essential workers cleared roads, led animal rescue efforts and much more.

Sea turtle rescue image (top left), courtesy of Texas Parks and Wildlife Department; "Brine" and snow plow images (bottom left), courtesy of TXDOT

State Revenue Watch

This table presents data on net state revenue collections by source. It includes most recent monthly collections, year-to-date (YTD) totals for the current fiscal year and a comparison of current YTD totals with those in the equivalent period of the previous fiscal year.

These numbers were current at press time. For the most current data as well as downloadable files, visit **comptroller.texas.gov/transparency.**

Note: Texas' fiscal year begins on Sept. 1 and ends on Aug. 31.

NET STATE REVENUE — All Funds Excluding Trust

(AMOUNTS IN THOUSANDS)

Monthly and Year-to-Date Collections: Percent Change From Previous Year

Tax Collections by Major Tax	SEPTEMBER 2021	YEAR TO DATE: TOTAL	YEAR TO DATE: CHANGE FROM PREVIOUS YEAR
SALES TAX	$3,145,213	$3,145,213	22.25%
PERCENT CHANGE FROM SEPTEMBER 2020	22.25%		
MOTOR VEHICLE SALES AND RENTAL TAXES	547,399	547,399	20.50%
PERCENT CHANGE FROM SEPTEMBER 2020	20.50%		
MOTOR FUEL TAXES	321,253	321,253	9.22%
PERCENT CHANGE FROM SEPTEMBER 2020	9.22%		
FRANCHISE TAX	33,321	33,321	-31.24%
PERCENT CHANGE FROM SEPTEMBER 2020	-31.24%		
OIL PRODUCTION TAX	391,792	391,792	72.22%
PERCENT CHANGE FROM SEPTEMBER 2020	72.22%		
INSURANCE TAXES	31,066	31,066	19.17%
PERCENT CHANGE FROM SEPTEMBER 2020	19.17%		
CIGARETTE AND TOBACCO TAXES	61,152	61,152	-53.16%
PERCENT CHANGE FROM SEPTEMBER 2020	-53.16%		
NATURAL GAS PRODUCTION TAX	251,838	251,838	254.96%
PERCENT CHANGE FROM SEPTEMBER 2020	254.96%		
ALCOHOLIC BEVERAGES TAXES	121,979	121,979	56.49%
PERCENT CHANGE FROM SEPTEMBER 2020	56.49%		
HOTEL OCCUPANCY TAX	51,453	51,453	50.43%
PERCENT CHANGE FROM SEPTEMBER 2020	50.43%		
UTILITY TAXES[1]	2,622	2,622	-24.45%
PERCENT CHANGE FROM SEPTEMBER 2020	-24.45%		
OTHER TAXES[2]	-93,403	-93,403	-1,872.86%
PERCENT CHANGE FROM SEPTEMBER 2020	-1,872.86%		
TOTAL TAX COLLECTIONS	**$4,865,688**	**$4,865,688**	**23.32%**
PERCENT CHANGE FROM SEPTEMBER 2020	**23.32%**		

Revenue By Source	SEPTEMBER 2021	YEAR TO DATE: TOTAL	YEAR TO DATE: CHANGE FROM PREVIOUS YEAR
TOTAL TAX COLLECTIONS	$4,865,688	$4,865,688	23.32%
PERCENT CHANGE FROM SEPTEMBER 2020	23.32%		
FEDERAL INCOME	4,565,413	4,565,413	-23.64%
PERCENT CHANGE FROM SEPTEMBER 2020	-23.64%		
LICENSES, FEES, FINES AND PENALTIES	695,670	695,670	2.77%
PERCENT CHANGE FROM SEPTEMBER 2020	2.77%		
STATE HEALTH SERVICE FEES AND REBATES[3]	21,688	21,688	183.89%
PERCENT CHANGE FROM SEPTEMBER 2020	183.89%		
NET LOTTERY PROCEEDS[4]	284,432	284,432	10.54%
PERCENT CHANGE FROM SEPTEMBER 2020	10.54%		
LAND INCOME	276,801	276,801	96.26%
PERCENT CHANGE FROM SEPTEMBER 2020	96.26%		
INTEREST AND INVESTMENT INCOME	31,572	31,572	-89.04%
PERCENT CHANGE FROM SEPTEMBER 2020	-89.04%		
SETTLEMENTS OF CLAIMS	4,541	4,541	-79.95%
PERCENT CHANGE FROM SEPTEMBER 2020	-79.75%		
ESCHEATED ESTATES	27,751	27,751	49.47%
PERCENT CHANGE FROM SEPTEMBER 2020	49.47%		
SALES OF GOODS AND SERVICES	19,476	19,746	-46.65%
PERCENT CHANGE FROM SEPTEMBER 2020	-46.65%		
OTHER REVENUE	103,732	103,732	-14.43%
PERCENT CHANGE FROM SEPTEMBER 2020	-14.43%		
TOTAL NET REVENUE	**$10,897,033**	**$10,897,033**	**-5.20%**
PERCENT CHANGE FROM SEPTEMBER 2020	**-5.20%**		

[1] Includes public utility gross receipts assessment, gas, electric and water utility tax and gas utility pipeline tax.

[2] Includes taxes not separately listed, such as taxes on oil well services, coin-operated amusement machines, cement and combative sports admissions as well as refunds to employers of certain welfare recipients.

[3] Includes various health-related service fees and rebates that were previously in "license, fees, fines and penalties" or in other non-tax revenue categories.

[4] Gross sales less retailer commission and the smaller prizes paid by retailers.

Notes: Totals may not add due to rounding.

Excludes local funds and deposits by certain semi-independent agencies.

Includes certain state revenues that are deposited in the State Treasury but not appropriated.

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Appendix 6

FERC - NERC - Regional Entity Staff Report:

The February 2021 Cold Weather Outages in Texas and the South Central United States

Federal Energy Regulatory Commission
North American Electric Reliability Corporation
Regional Entities

FERC, NERC and Regional Entity Staff Report

The February 2021 Cold Weather Outages in Texas and the South Central United States

November 2021

FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Entities:

Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Corporation, Texas Reliability Entity and Western Electricity Coordinating Council

Acknowledgement

This report results from the combined efforts of many dedicated individuals in multiple organizations. The inquiry team (the Team) consisted of individuals from the Federal Energy Regulatory Commission (FERC or the Commission), the North American Electric Reliability Corporation (NERC), Regional Reliability Entities Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RF), SERC Corporation (SERC), Texas Reliability Entity (Texas RE) and Western Electricity Coordinating Council (WECC), as well as the Department of Energy and the National Oceanic and Atmospheric Administration (NOAA), all of whom are named in Appendix A. They were assisted by other non-Team members within their respective organizations.

Contents

I. Executive Summary

This report[1] describes the severe cold weather event occurring between February 8 and 20, 2021 and how it impacted the reliability of the bulk electric system[2] ("BES" or colloquially known as the grid) in Texas and the South Central United States (hereafter known as "the Event"). During the Event, extreme cold temperatures and freezing precipitation led 1,045 individual BES generating units,[3] (with a combined 192,818 MW of nameplate capacity) in Texas and the South Central United States to experience 4,124 outages, derates or failures to start. Each individual generating unit could, and in many cases, did, have multiple outages from the same or different causes. To provide perspective on how significant the generating unit outages were, including generation already on planned or unplanned outages, the Electric Reliability Council of Texas (ERCOT) averaged 34,000 MW of generation unavailable (based on expected capacity[4]) for over two consecutive days, from 7:00 a.m. February 15 to 1:00 p.m. February 17, equivalent to nearly half of its all-time winter peak electric load of 69,871 MW.

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[1] This report is written for a reader who is already familiar with principles of energy markets, electric transmission system operations and generating unit operations. For readers who are not as familiar, the Team has linked to several resources which may be helpful:

[2] Bulk electric system generally means all transmission elements operated at 100 kV or higher and real power and reactive power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. *See* NERC Glossary of Terms at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[3] A single generating unit can range from a 75 MW gas turbine, to a 1,000-MW-plus nuclear unit, to a wind farm with multiple wind turbines. For purposes of the report, only BES generating units were considered, i.e., those with a nameplate rating of 75 MW or higher.

[4] Expected capacity includes any expected seasonal capacity derates, and for intermittent resources (e.g., wind, solar resources), expected capacity is calculated based on weather conditions. For example, a 100 MW wind generation facility may be 20 MW, based on the variability of wind during the winter peak timeframe.

The Event was the fourth cold-weather-related event in the last ten years to jeopardize BES reliability,[5] and with a combined 23,418 MW of manual firm load shed,[6] the largest controlled firm load shed event in U.S. history. In each of the four BES events, planned and unplanned generating unit outages caused energy emergencies, and in 2011, 2014 and 2021 they triggered the need for firm load shed. The unplanned generation outages that escalated during the Event were more than twice as large as the previous largest event, in 2011 (65,622 MW versus 14,702 MW).

More than 4.5 million people in Texas lost power during the Event, and some went without power for as long as four days, while exposed to below-freezing temperatures for over six days.[7] At least 210 people died during the Event, with most of the deaths connected to the power outages, of causes including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions.[8] Among the deaths were a mother and her seven-year-old daughter,[9] and an 11-year-old boy who died in his bed,[10] who all died of carbon monoxide poisoning, and a 60-year-old disabled man who died of hypothermia.[11] A grandmother and three children trying to keep warm

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[5] In February 2011, an arctic cold front impacted the southwest U.S. and resulted in 29,700 MW of generation outages, natural gas facility outages and emergency power grid conditions with need for firm customer load shed. Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations (Aug. 2011) (https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf) (hereafter, 2011 Report). In January 2014, a polar vortex affected Texas, central and eastern U.S., triggering 19,500 MW of generation outages, natural gas availability issues and resulted in emergency conditions including voluntary load management. NERC "*Polar Vortex Review*" (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf (hereafter Polar Vortex Review). And in January 2018, an arctic high-pressure system and below average temperatures in the South Central U.S. resulted in 15,800 MW of generation outages and the need for voluntary load management emergency measures. See South Central United States Cold Weather Bulk Electric Systems Event of January 17, 2018 (July 2019), https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf (hereafter, 2018 Report).

[6] Manual firm load shed, often referred to as rolling or rotating blackouts, is when BES operators order a percentage of the demand or load to be temporarily disconnected, to avoid system instability or other system emergencies. Customers lost electric distribution service due both to manual firm load shed, as well as to weather-related unplanned outages (such as downed power lines). In addition to being the largest controlled firm load shed event in U.S. history, the Event was also the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 Western Interconnection blackout.

[7] Paul Takashi, *I lost my best friend: How Houston's winter storm went from wonderland to deadly disaster*, Houston Chronicle (May 25, 2021), https://www.houstonchronicle.com/news/investigations/article/failures-of-power-series-part-2-blackouts-houston-16189658.php.

[8] Andrew Weber, *Texas Winter Storm Toll Goes Up to 210, Including 43 Deaths in Harris County*, Houston Public Media (July 14, 2021), https://www.houstonpublicmedia.org/articles/news/energy-environment/2021/07/14/403191/texas-winter-storm-death-toll-goes-up-to-210-including-43-deaths-in-harris-county/.

[9] ABC 13 Staff, *Carbon Monoxide "We tried our best to save them"*, ABC 13 Eyewitness News (February 17, 2021), https://abc13.com/houston-woman-and-daughter-die-from-carbon-monoxide-poisoning-mom-after-leaving-car-running-inside-garage-dangers-during-texas-winter-storn-storm-2021/10348847/

[10] KHOU Staff, *Autopsy Results Released for 11-Year-Old Who Died During the Texas Winter Freeze,* KHOU 11 News Channel (May 12, 2021) https://www.khou.com/article/news/local/conroe-police-autopsy-reveals-11-year-old-boy-died-carbon-monoxide-poisoning-houston-winter-storm/285-fbae9d3f-45cd-41bb-9047-33665fef8f18#:~:text=Autopsy%20results%20released%20for%2011,their%20mobile%20home%20lost%20power.

[11] Paul Takashi, *I lost my best friend: How Houston's winter storm went from wonderland to deadly disaster*, Houston Chronicle (May 25, 2021), https://www.houstonchronicle.com/news/investigations/article/failures-of-power-series-part-2-blackouts-houston-16189658.php.

using a wood-burning fireplace died in a house fire.[12] In cities including Austin, Houston and San Antonio, over 14 million people were ordered to boil drinking and cooking water, and multiple cities ordered water conservation measures, due to broken pipes and power outages (which lowered water pressure).[13] After the city of Denton, Texas, lost its gas supply, it was forced to cut power to nursing homes and water pumping stations.[14]

Analysts with the Federal Reserve Bank of Dallas estimated that the outages caused direct and indirect losses to the Texas economy of between $80 to $130 billion.[15] A separate Federal Reserve Bank of Dallas analysis described the effect on the petrochemical and refining sector as "hurricane-level," comparable to 2008's Hurricane Ike, with a 50 percent drop in February 2021 production as compared to January. It also predicted continuing effects on the supply chain through the end of 2021 as a result of the disruptions in February.[16]

A. Synopsis of Event

In the early morning hours of February 15, 2021, an arctic front moving through Texas and the South Central U.S. began to take its toll. As temperatures dropped, more and more generating units throughout Texas failed in ERCOT. The same front led to generating units to fail to a lesser extent in the South Central U.S. footprints of Midcontinent Independent System Operator (MISO) South and Southwest Power Pool (SPP).[17] Responding to the loss of generation, and to keep the electrical system from cascading outages and total blackout, the system operators at ERCOT began to issue orders for rotating outages of electricity to customers (known as manual firm load shed). ERCOT ultimately had to shed 20,000 MW of firm load at the worst point of the Event, with SPP and MISO

[12] Anna Bauman, *Grandmother, 3 Children Dead in Sugar Land Fire,* Houston Chronicle (Feb. 16, 2021), https://www.houstonchronicle.com/news/houston-texas/houston/article/Sugar-Land-fire-fatalities-15953492.php%20https://www.google.com/amp/s/abc13.com/amp/sugar-land-house-fire-children-killed-deadly/10352669

[13] Talal Ansari, *New Winter Storm Threatens Fragile Power Grids in Texas, Other Parts of U.S.*, The Wall Street Journal New (Feb. 22, 2021), https://www.wsj.com/articles/new-winter-storm-threatens-fragile-electrical-grids-in-texas-other-parts-of-u-s-11613588298; Elizabeth Findell, *Texas Cities Under Boil-Water Orders*, The Wall Street Journal (Feb. 19, 2021), https://www.wsj.com/articles/texas-cities-under-boil-water-orders-11613671450.

[14] Community Emergency Preparedness Committee, *City of San Antonio Community Emergency Preparedness Committee Report: A Response to the February 2021 Winter Storm* (Jun. 24, 2021), https://www.sanantonio.gov/Portals/5/files/CEP%20Report%20Final.pdf; Russell Gold, *Inside One Texas City's Struggle to Keep Power and Water Going*, The Wall Street Journal (Feb. 17, 2021), https://www.wsj.com/articles/texas-city-deals-with-no-power-no-water-during-big-chill-11613590412.

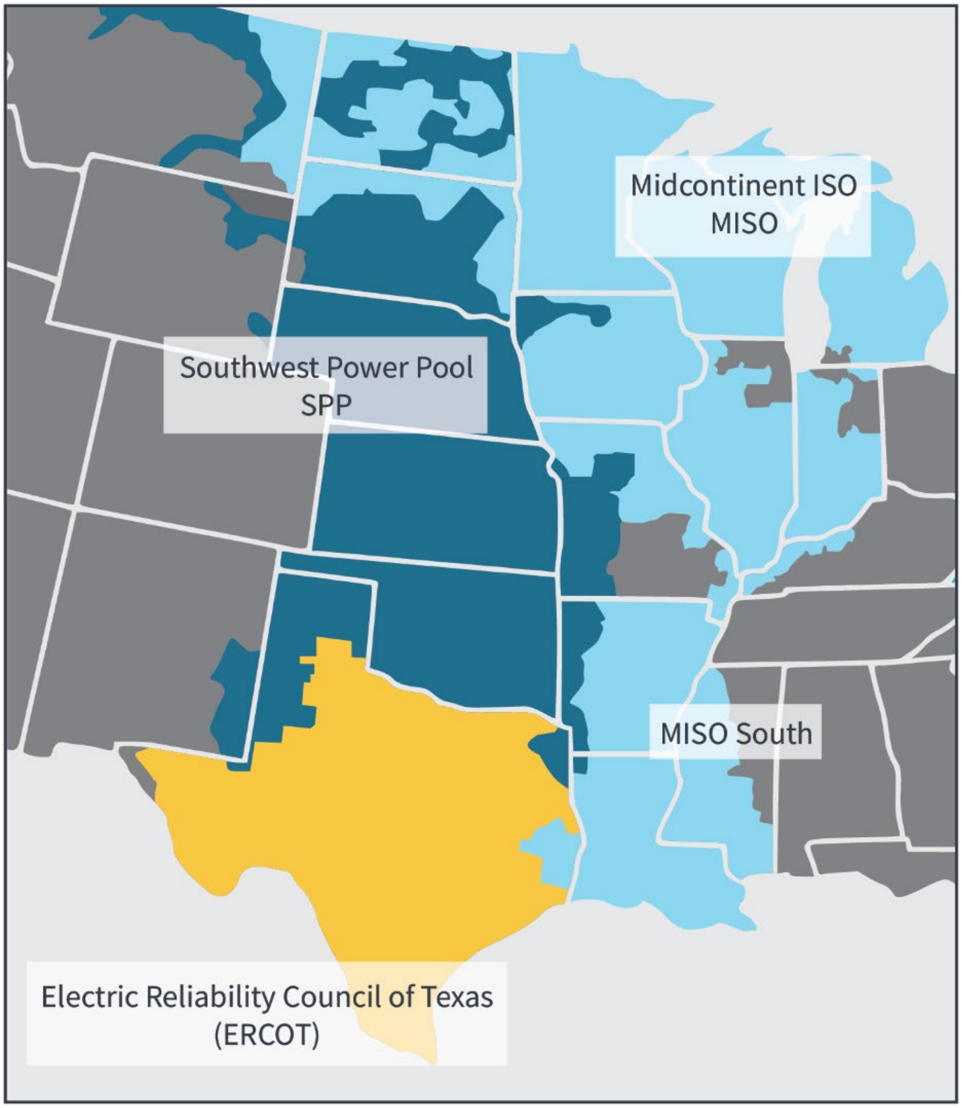
[15] Garrett Golding et al., *Cost of Texas' 2021 Deep Freeze Justifies Weatherization*, Dallas Fed Economics (Apr. 15, 2021), https://www.dallasfed.org/research/economics/2021/0415.

[16] Jesse Thompson, *Texas Winter Deep Freeze Broke Refining, Petrochemical Supply Chains*, Southwest Economy (Second Quarter 2021), https://www.dallasfed.org/research/swe/2021/swe2102/swe2102c (Texas holds nearly 75 percent of "basic U.S. chemical capacity," relied upon by global supply chains, and as much as 80 percent of this capacity was offline after the storm).

[17] See Figure 1 below for map of the Event Area: ERCOT, SPP and MISO South. Except for the figures regarding the entire MISO footprint in section II.B. below, the Team gathered data about and focused on MISO South, because the bulk of the manual load shed and unplanned generation outages experienced in MISO occurred in MISO South.

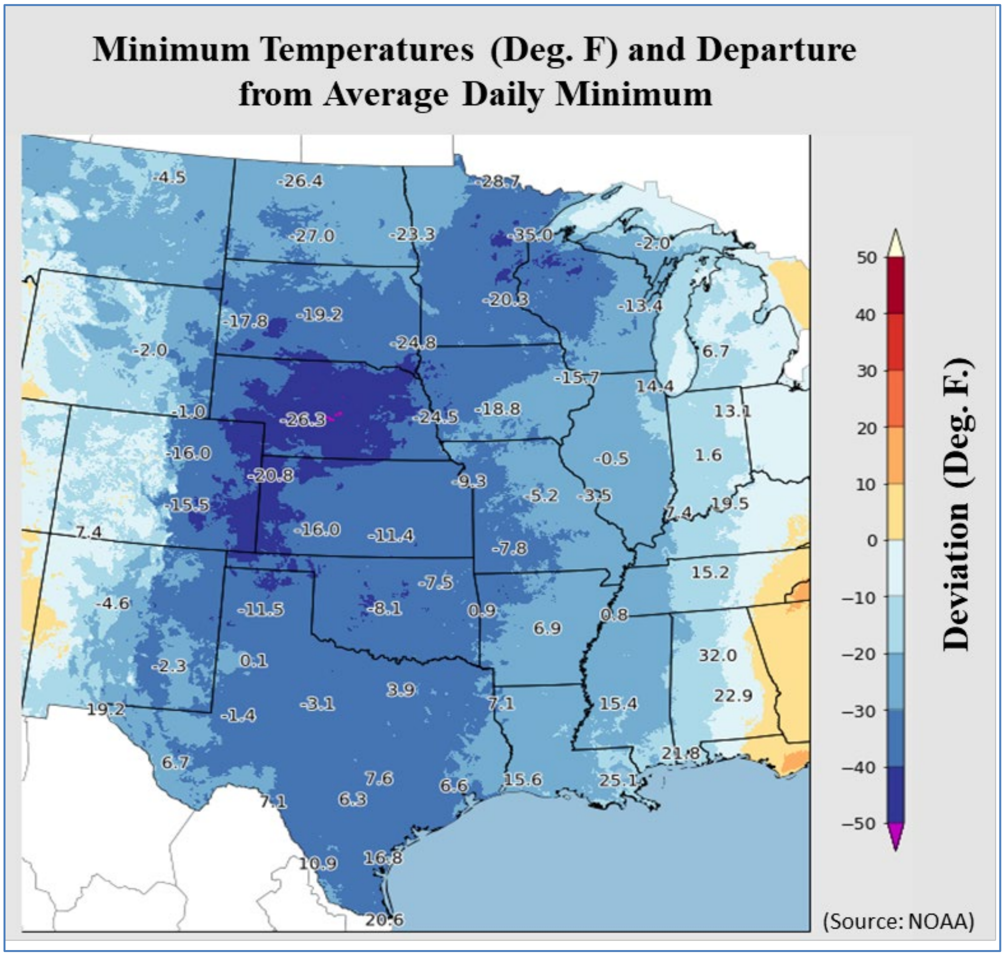
operators shedding a combined total of 3,418 MW of firm load on February 15 and 16, at their worst points.

Figure 1: Event Area: ERCOT, SPP and MISO South



A confluence of two causes, both triggered by cold weather, led to the Event, part of a recurring pattern for the last ten years. First, generating units unprepared for cold weather failed in large numbers. Second, in the wake of massive natural gas production declines, and to a lesser extent, declines in natural gas processing, the natural gas fuel supply struggled to meet both residential heating load and generating unit demand for natural gas, exacerbated by the increasing reliance by generating units on natural gas.[18] Natural gas pipeline capacity is for the most part designed, certificated and constructed to accommodate firm transportation commitments, while many natural gas-fired generating units rely on non-firm commodity and/or pipeline transportation contracts.

Figure 2: Severe Cold Weather Conditions – February 15, 2021



ERCOT, MISO and SPP all knew from weather forecasts and warnings issued by NOAA and other meteorologists beginning in early February that an arctic cold front was expected. All three issued cold weather preparation notices to their generation and transmission operators based on when the cold weather was expected to reach their respective footprints: ERCOT and SPP on February 8, and MISO on February 9. Temperatures began to drop below freezing in ERCOT and SPP on February 8, but low temperatures dropped even lower during the week of February 14, reaching their nadir on February 15 and 16. Daily low temperatures for February 15 in the Event Area were as much as 40

[18] Hereafter, "natural gas fuel supply issues" means the reduction in natural gas fuel supply caused by a combination of natural gas production declines, related natural gas pipeline pressure issues, and terms and conditions of electric generating units' natural gas commodity and transportation contracts.

to 50 degrees[19] lower than average daily minimum temperatures for February 15, as shown in Figure 2, above. In addition to the arctic air, the cold front brought periods of freezing precipitation and snow to large parts of Texas and the South Central U.S., starting February 10, and extending into the week of February 14, 2021.

Unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins[20] to prevent imminent freezing issues, beginning on approximately February 7, as well as unplanned outages of natural gas gathering and processing facilities, resulted in a decline of natural gas available for supply and transportation to many natural gas-fired generating units in the South Central U.S. Once natural gas supply outages began at the wellhead, they rippled throughout the natural gas and electric infrastructure, causing processing outages and reductions, pipeline declarations of Operational Flow Order (OFO)s[21] and force majeure, and outages and derates of natural gas-fired generating units. U.S. natural gas production in February 2021 experienced the largest monthly decline on record.[22] Between February 8 and 17, the total natural gas production in the U.S. Lower 48 fell by 28 percent. In the Event Area, Texas, Oklahoma, and Louisiana gas production at its lowest point of February 17 declined by an estimated 21 Bcf/d, exceeding a 50 percent decline when compared to average production in January 2021. Average production declines in those three states constituted over 80 percent of the total production declines across the lower 48 states during the period from February 15-20 when compared to average production in January 2021. Most producing regions of the U.S. saw a sharp decline and recovery associated with temperature—when temperatures fell, regional production dropped, and as temperatures rose after the Event, regional production recovered, ultimately to pre-Event levels by late February.[23]

During the week of February 7, ERCOT and SPP experienced rising load, as well as increasing generating unit outages, primarily caused by wind turbine blade freezing as a result of freezing precipitation, and natural gas fuel supply issues. Although ERCOT and SPP issued several alerts, they did not have to take any emergency actions because enough generation remained online to meet load.

But the week of February 14 brought far colder weather, and ERCOT, SPP and MISO all faced emergency conditions simultaneously. Temperatures dropped as low as six degrees in Austin, eight degrees in Dallas and ten degrees in Houston. Unplanned generating unit outages and derates in ERCOT escalated sharply in the late-night hours of February 14 into the early morning hours of February 15, and ERCOT set an all-time winter peak record for system load of 69,871 MW at 8:00 p.m. on February 14. The combination of high load and increasing unplanned generating unit outages caused ERCOT's Physical Responsive Capability to drop below acceptable levels, and at

[19] All temperatures will be in Fahrenheit unless otherwise stated.
[20] A shut-in well is a well that has been shut off so that no natural gas is flowing or being produced. *See* American Gas Association (AGA) Natural Gas Glossary, at https://www.aga.org/natural-gas/glossary/, "Shut-In" and "Shut-In Well" definitions. Some entities performed pre-emptive shut-ins to protect components from freezing, which resulted in well outages.
[21] See sidebar on Pipeline Communications on page 71.
[22] Mike Kopalek & Emily Geary, February 2021 weather triggers largest monthly decline in U.S. natural gas production, Today In Energy (May 10, 2021) https://www.eia.gov/todayinenergy/detail.php?id=47896
[23] Modeled data provided by IHS (www.ihsmarkit.com/index.html).

12:15 a.m., it issued the first stage of an Energy Emergency Alert (EEA),[24] EEA 1, which allowed it to deploy demand response resources.

Beginning in the early hours of February 15 at approximately 12:18 a.m., the ERCOT Interconnection frequency,[25] which measures the balance of supply and demand on the BES and is thus a critical indicator of BES reliability status, began to fall below the normal band level. At first ERCOT was able to recover its frequency to normal levels through deployment of load management measures, but it continued to suffer generating unit outages and needed to order its first 1,000 MW of load shed at 1:20 a.m. As system frequency continued to fall, ERCOT BA operators ordered an additional 1,000 MW of load shed, but generating units continued to fail and frequency declined to the point that ERCOT operators had only nine minutes to prevent approximately 17,000 MW of generating units from tripping due to underfrequency relays, which could potentially cause a complete blackout of the ERCOT Interconnection. ERCOT system frequency eventually bottomed out, and finally rose above the generator trip level after remaining below for over four minutes. However, unplanned generating outages continued, and ERCOT system operators continued to shed firm load to balance demand against the massive generating unit losses. For over two days, including generating units already on planned or unplanned outages when the Event began as well as unplanned outages that began during the Event, ERCOT averaged 34,000 MW of generation outages (based on expected capacity). To balance ERCOT's load against those staggering generation losses, ERCOT operators continued to order firm load shed, lasting nearly three consecutive days, and peaking at 20,000 MW by 7 p.m. on February 15.

SPP and MISO in the Eastern Interconnection also faced challenges balancing rising load with rapidly decreasing generation. SPP averaged 20,000 MW of generation unavailable (based on expected capacity) for over four consecutive days, from February 15 to 19, and MISO South averaged 14,500 MW of generation unavailable for two consecutive days, from February 16 to 18. As a result, each had its own energy and transmission emergencies, starting on February 15. Unlike ERCOT, which can only import slightly more than 1,000 MW over its direct current ties, SPP and MISO imported power from other Balancing Authorities to make up for their increasing load levels and generation shortfalls, because the eastern part of the Eastern Interconnection did not have the same arctic weather conditions. Specifically, MISO was able to import large amounts of power from neighbors to the east (e.g. PJM Interconnection, LLC), and SPP was able to transfer some of that power through MISO. Those east-to-west transfers into MISO peaked at nearly 13,000 MW on February 15. The heavy transfers, combined with the widespread generation outages, created local and system-wide transmission emergencies on February 15 and 16, which required MISO operators to order a combined 2,000 MW of firm load shed (non-coincident). On the same days, SPP experienced transmission emergencies on a system-wide basis, although they did not result in any firm load shed. SPP ordered shed firm load on February 15 and 16 for energy emergencies for a total of over four hours spread over the two days, reaching 2,718 MW at its worst point following MISO's curtailment SPP's import power due to MISO's transmission emergency. On the evening

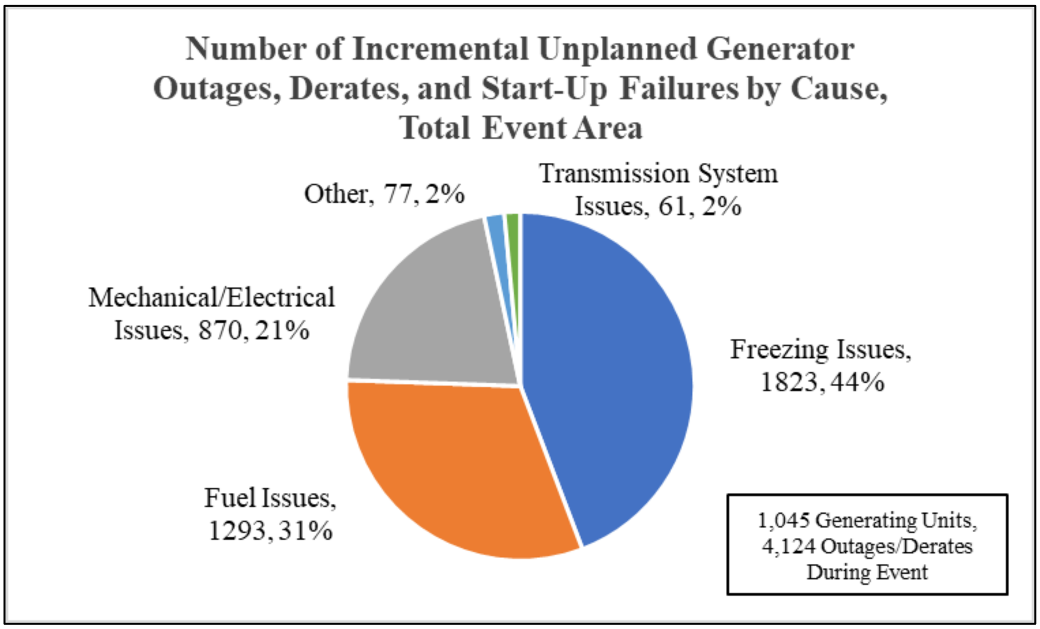
[24] See Appendix K for a description of the levels of alerts and Energy Emergencies.
[25] Interconnection frequency is measured in Hertz (Hz). *See* NERC Glossary of Terms, Actual Frequency.

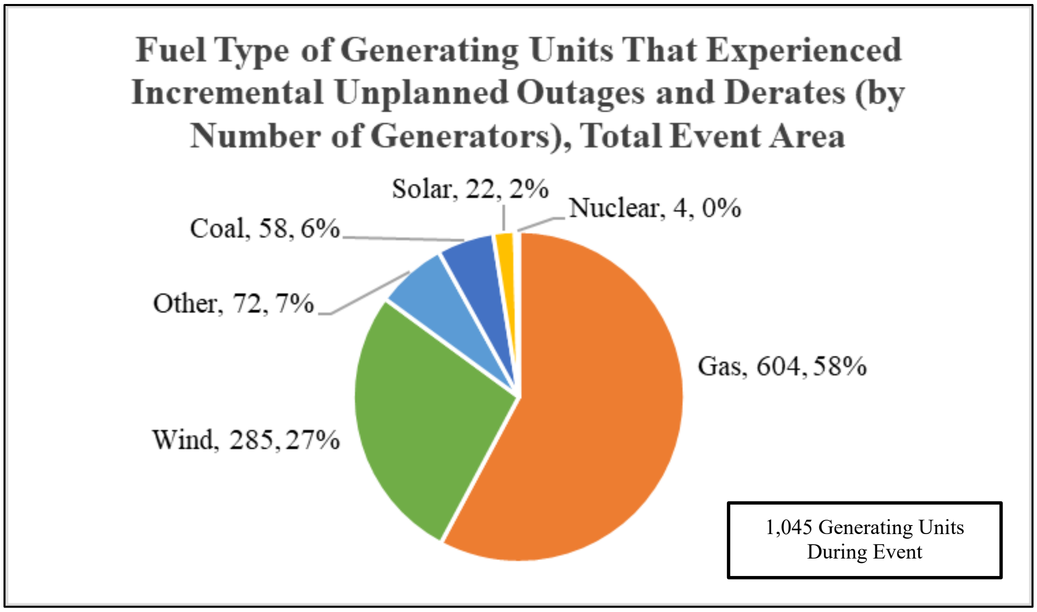
of February 16, MISO ordered firm load shed that lasted over two hours, reaching 700 MW at its worst point for an energy emergency in MISO South.

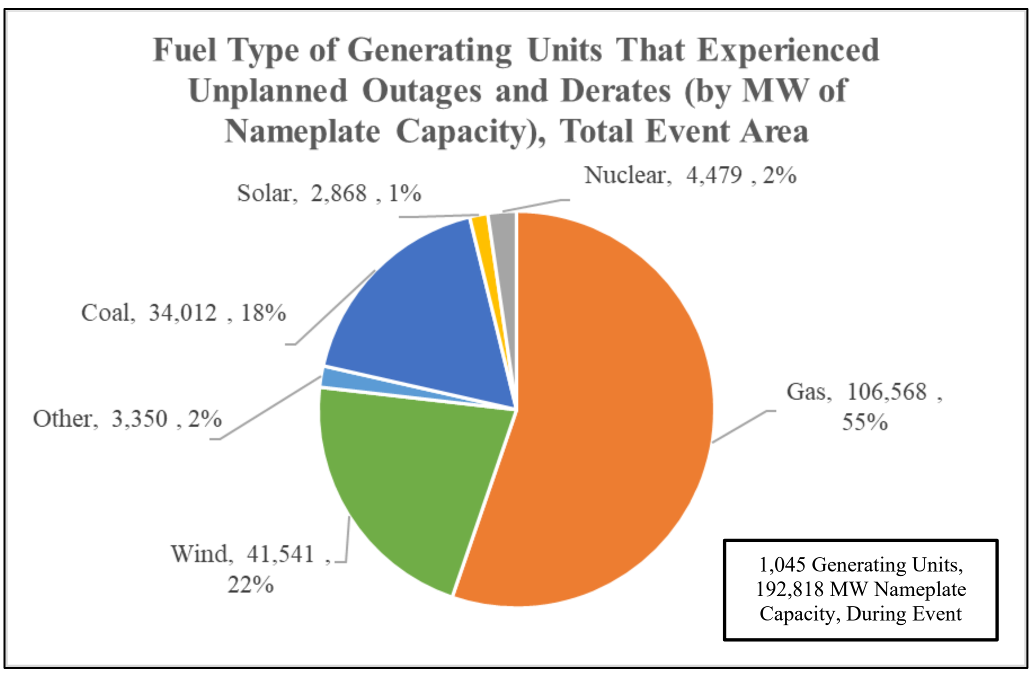
B. Key Findings and Causes

From February 8 through 20, in the Event Area, a total of 1,045 individual generating units—58 percent natural gas-fired, 27 percent wind, six percent coal, two percent solar, seven percent other fuels, and less than one percent nuclear—experienced 4,124 outages, derates or failures to start. Of those outages, derates, and failures to start, 75 percent were caused by either freezing issues (44.2 percent) or fuel issues (31.4 percent), as shown in Figure 3, below.

Figure 3: Incremental Unplanned Generating Unit Outages, Derates and Failures to Start, Total Event Area: by Cause, by Fuel Type, and by MW of Nameplate Capacity



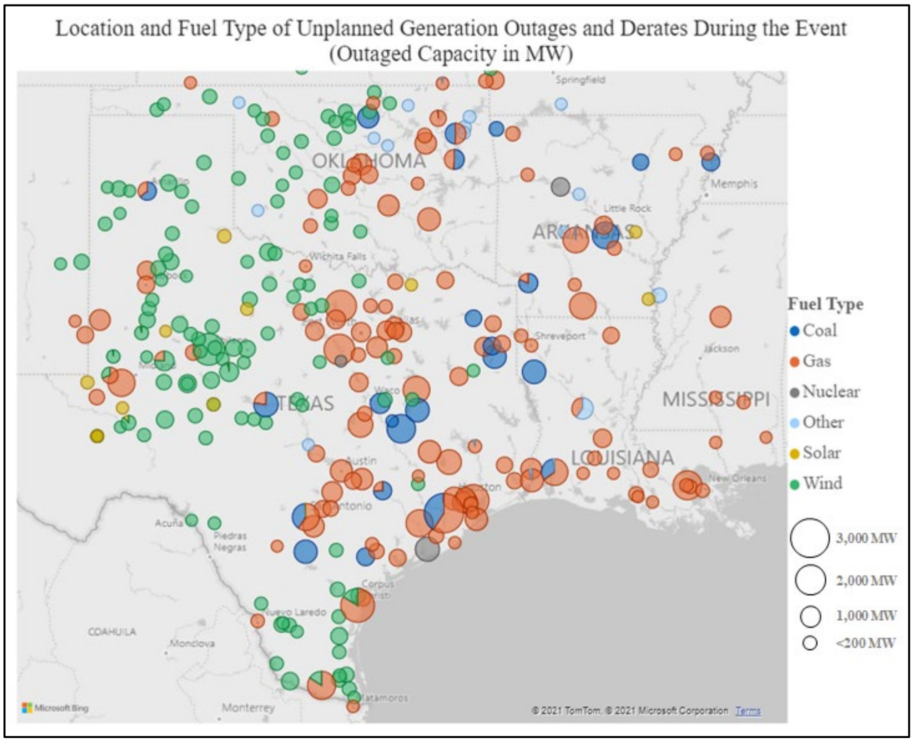




Natural gas fuel supply issues caused the majority, 87 percent, of the 31.4 percent of outages and derates due to fuel issues, and caused 27.3 percent of all outages, derates and failures to start during the Event.

In addition to the 44.2 percent of outages and derates caused by freezing issues, the 21 percent caused by "mechanical/electrical issues" also indicated a relationship with the cold temperatures—as temperatures decreased, the number of generating units outaged or derated due to mechanical/electrical issues increased. Figure 4, below depicts the locations of the generation outages, derates and failures to start during the Event.

Figure 4: Location and Fuel Type of Unplanned Generation Outages and Derates During the Event (Outaged Capacity in MW)



Despite multiple prior recommendations by FERC and NERC, as well as annual reminders via Regional Entity workshops, that generating units take actions to prepare for the winter (and providing detailed suggestions for winterization),[26] 49 generating units in SPP (15 percent, 1,944 MW of nameplate capacity), 26 in ERCOT (7 percent, 3,675 MW), and three units in MISO South (four percent, 854 MW), still did not have any winterization plans, and 81 percent of the freeze-related generating unit outages occurred at temperatures above the unit's stated ambient design temperature. Generating units that experienced freeze-related outages above the unit's stated ambient design temperature represented about 63,000 MW of nameplate capacity.

[26] 2011 Report, Recommendations 11, 14-19 https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf, 2018 Report, Recommendation 1 https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf.

C. Recommendations

Key Recommendations[27]. In response to the continued failures of generating units due to freezing issues, the Team recommends revising the mandatory Reliability Standards to require:

- Generator Owners (GOs) to identify and protect cold-weather-critical components (1a and 1b);
- GOs to retrofit existing generating units, and when building new generating units, to operate to specific ambient temperatures and weather based on extreme temperature and weather data, and account for effects of precipitation and cooling effect of wind (1f);
- GOs/ Generator Operators (GOPs) to perform annual training on winterization plans (1e);
- GOs that experience freeze-related outages to develop Corrective Action Plans (1d);
- GOs/GOPs to provide the BA with the percentage of the total generating unit capacity that the BA can rely upon during the "local forecasted cold weather" (1g); and
- GOs to account for effects of precipitation and accelerated cooling effect of wind when providing temperature data to BAs (1c).

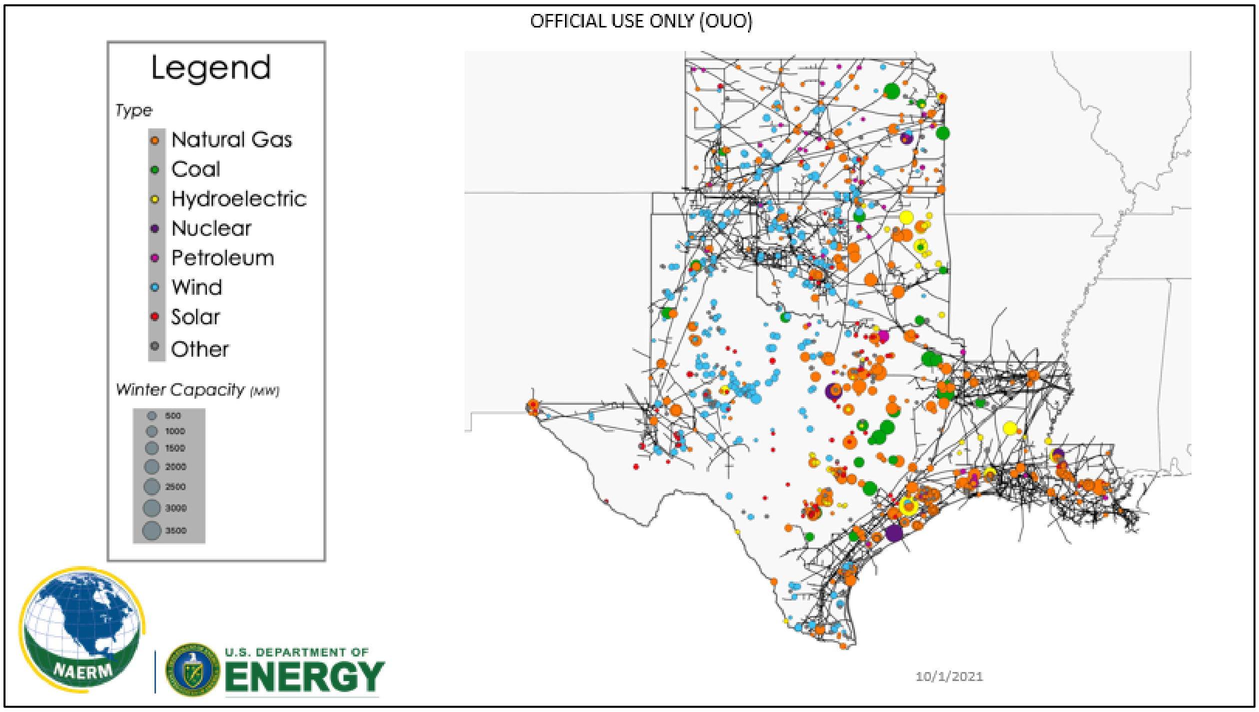
In addition to revising the Reliability Standards, the Team also recommends that GOs have the opportunity to be compensated for the costs of retrofitting their generating units to perform at specified ambient temperatures (or designing any new units to do so) (2); that FERC, NERC and the Regional Entities host a joint technical conference to discuss how to improve the winter readiness of generating units before the recently-approved Reliability Standards revisions[28] become effective (3); and that GOs'/GOPs' freeze protection plans include certain times for inspection and maintenance (e.g., before and after winter and before specific cold weather events) (4).

Regarding natural gas fuel issues, the second largest cause of the generating unit outages, the Team recommends that Congress, state legislatures and regulatory agencies with jurisdiction over natural gas infrastructure facilities require those natural gas facilities to implement and maintain cold weather preparedness plans (5); that natural gas infrastructure facilities undertake voluntary measures to prepare for cold weather (6); and that GOs/GOPs identify the reliability risks related to their natural gas fuel contracts so that they can provide the BAs with the percentage of total generating unit capacity that the BA can rely upon during the "local forecasted cold weather" (8). To address the recurring challenges stemming from natural gas-electric infrastructure interdependency, as shown in part by Figure 5 below,[29] the Team recommends that FERC consider establishing a forum

[27] Each Recommendation number is in parentheses after the summary of the Recommendation.
[28] In August, the Commission approved revisions to the NERC Reliability Standards to address cold weather, including a new requirement for generating units to have a cold weather preparedness plan. However, the effective date for these revisions is April 1, 2023. See 176 FERC ¶ 61,119 (August 2021).
[29] Figure 5, used by permission of the Department of Energy, shows the locations of both electric generating units, and the interstate natural gas pipelines available to deliver fuel to natural gas-fired generating units. The Team thanks the

to identify concrete actions to improve the reliability of the natural gas infrastructure system[30] necessary to support the BES (7).

Figure 5: Interdependency of Electric and Natural Gas Infrastructure, South Central U.S., and Texas



The Team also recommends three additional revisions to the Reliability Standards: to protect critical natural gas infrastructure from manual and automatic load shedding in order to avoid adversely affecting BES reliability (1i); to require Balancing Authorities' operating plans to prohibit use of critical natural gas infrastructure loads for demand response (1h); and to separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS) and use the UFLS circuits only as a last resort (1j).

__**Other Recommendation Areas**__. In addition to the Reliability Standards revisions, the Team makes recommendations in areas including seasonal reserve margin calculations (9), effects of cold weather on mechanical fatigue (11), increasing the flexibility of manual load shedding (10), GO/GOP use of weather forecasts (12), coordination of protective relay settings associated with generator underfrequency relays (13), coordination of UFLS relay settings with generating unit time-delay

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Department of Energy for sharing its North American Electric Resilience Model (NAERM). The NAERM is intended to bring together models of multiple types of infrastructure in the United States, such as natural gas, electric, telecommunications, water, etc., and simulate various contingencies. DOE used the NAERM to prepare Figure 5 and the NAERM was helpful to the Team in understanding interdependencies between the natural gas infrastructure and bulk-electric systems.

[30] "Natural gas infrastructure" refers to natural gas production, gathering, processing intrastate and interstate pipelines, storage and other infrastructure used to move natural gas from wellhead to burner tip.

protection systems (22), increasing real-time monitoring of gas wellheads (14), emergency response centers for severe weather events (15), improving near-term load forecasts for extreme weather conditions (16), analyzing intermittent generation effects to improve load forecasts (17), rapidly-deploying demand response (18), additional load shed training for system operators (21), retail incentives for energy efficiency improvements (19), reducing the time for generation and transmission outages to be reported (23), and studies of large power transfers during stressed conditions (20). Finally, the Team recommends additional study in five areas: black start unit reliability (26), additional ERCOT connections to other interconnections (25), potential measures to address natural gas supply shortfalls (24), potential effects of low-frequency events on generators in the Western and Eastern Interconnections (27), and guidelines for identifying critical natural gas infrastructure loads (28).

II. Introduction

A. Inquiry Process

On February 16, 2021, while the Event was still occurring, the Commission and NERC jointly announced a FERC-NERC-Regional Entity staff inquiry "into the operations of the BES during the extreme winter weather conditions currently being experienced by the Midwest and South Central states in February 2021."[31]

Staff from FERC, NERC and all six of the Regional Entities quickly formed a team (the Team) of over 50 subject-matter experts and identified the scope of the inquiry to include: assessing what occurred during the Event, identifying commonalities with previous cold weather events and any lessons that should be incorporated in the development by NERC of cold weather Reliability Standards, and making recommendations to avoid similar events in the future. The scope did not include potential market manipulation or market design issues, which were being examined by the Commission's Office of Enforcement, among others, but rather would focus on reliability of the BES. As with other inquiries, the purpose was not to determine whether there may have been violations of applicable regulations, requirements, or standards subject to the Commission's jurisdiction, but to make findings and recommendations with the aim of preventing future events.

The Team was divided into three sub-teams with specific expertise: Generation, Natural Gas, and Grid Operations and Planning. Each sub-team requested data directly from the affected entities, including Generation Owners, Balancing Authorities, Reliability Coordinators, Transmission Operators, and natural gas infrastructure entities. In total, the Team issued over 400 data requests. Team members had multiple virtual meetings with ERCOT, MISO and SPP, as well as representative natural gas infrastructure entities, to understand their operations during the Event, and followed up with countless calls and emails to clarify and confirm data. Due to the COVID-19 Pandemic, the Team was unable to perform site visits, but Team members had visited many of the involved entities previously, including ERCOT, MISO, SPP, and multiple types of generating units that experienced freezing issues in 2011.

The Team analyzed the data for several purposes: establishing an evidence-based description of the Event, determining the causes of the BES disruptions, including record levels of manual firm load shed in ERCOT, and preparing preliminary findings and recommendations. After the Team prepared its first set of preliminary findings and recommendations, it conducted outreach calls, during which it read the preliminary findings and recommendations and solicited comments, issues

[31] **Press Release,** FERC, NERC to Open Joint Inquiry into 2021 Cold Weather Grid Operations | Federal Energy Regulatory Commission (Feb. 16, 2021)

and questions.[32] The Team fact-checked report drafts with ERCOT, MISO and SPP, as well as through multiple levels of Team and FERC, NERC and Regional Entity management review. The Team also reviewed other reports on the Event, some of which are cited in this report.

B. System Overview

1. Reliability Roles

NERC categorizes the entities responsible for planning and operating the BES in a reliable manner into multiple functional entity types. The NERC roles most relevant to the Event are Reliability Coordinators (RCs), Balancing Authorities (BAs), Generator Owners (GOs), Generator Operators (GOPs), Transmission Owners (TOs), Transmission Operators (TOPs), Planning Coordinators (PCs), and Transmission Planners (TPs). Several of the affected entities, especially ERCOT, MISO and SPP, played multiple reliability roles during the Event.[33]

2. Description of Affected Electric Grid Entities

ERCOT. ERCOT is an Independent System Operator (ISO)[34] that covers approximately 75 percent of the landmass in Texas, excluding the El Paso Area, part of the northern panhandle, and part of east Texas north and east of Houston to the Louisiana border. ERCOT manages 90 percent of the load in Texas as a BA, serves as the RC,[35] and operates the Texas energy and ancillary services markets.[36] ERCOT schedules power over 46,500 miles of transmission lines and monitors over 700 generating units.[37] ERCOT's generation fleet is composed of 52 percent natural gas, 25 percent wind, 12 percent coal, four percent nuclear, five percent solar, and one percent storage/other (see Figure 6 below). ERCOT is a summer peaking region and experienced its highest peak demand (or

[32] The Team conducted this outreach with ERCOT, MISO, SPP, the Texas Public Utility Commission, the Texas Railroad Commission, and trade groups including Edison Electric Institute, National Association of Regulatory Utility Commissioners, National Rural Electric Cooperative Association, Interstate Natural Gas Association of America, Natural Gas Supply Association, Electric Power Supply Association, ISO/RTO Council, American Public Power Association, North American Transmission Forum, Electricity Consumers Resource Council, the American Clean Power Association, Northwest Public Power Association, Solar Energy Industries Association, and the Western Interconnection Compliance Forum.
[33] Appendix J describes the Categories of NERC Registered Entities who operate the BES.
[34] ISOs and RTOs do not own transmission or generation assets, but rather dispatch them over a large footprint, as well as operating energy markets and other related markets (capacity, ancillary services). For reliability purposes, they tend to serve at least two important reliability functions, the Balancing Authority, which balances load and generation, and the Reliability Coordinator, which oversees reliability of the bulk electric system over a wide area.
[35] In addition, ERCOT also serves as a Balancing Authority (BA), Planning Authority (PA)/Planning Coordinator (PC), and shares Transmission Operator (TOP) duties with transmission utilities in its footprint.
[36] Unlike some ISOs/RTOs, ERCOT does not have a capacity market.
[37] http://www.ercot.com/

"load") to date on August 12, 2019, when its load reached 74,820 MW.[38] ERCOT expected to, but did not, surpass this record in summer 2021.[39]

In the ERCOT market, Qualified Scheduling Entities (QSEs) submit bids and offers on behalf of generating units or load serving entities. QSEs submit offers to sell and/or bids to buy energy in the day-ahead market and the real-time market. The QSE is also responsible for submitting a Current Operating Plan for all generating units it represents and for offering or procuring ancillary services as needed to serve its represented load.[40] Most of the communication during normal and emergency operations is between ERCOT and the QSEs, and the QSEs are responsible for coordinating with the individual generating units or other entities represented.

MISO and SPP. MISO is an ISO that operates the power grid across 15 states and the Canadian province of Manitoba, and serves as a BA and RC, among other reliability roles.[41] MISO operates 65,800 miles of transmission lines, and experienced its highest peak load to date, 130,917 MW, on July 20, 2011.[42] MISO's generating capacity is 198,933 MW, comprised of 42 percent natural gas-fired generation, 29 percent coal, 19 percent renewables and 8 percent nuclear generation. Only the MISO South area of its footprint was involved in the Event, and it has a fleet which is 61 percent natural gas, 17 percent coal, 13 percent nuclear, nine percent other, and notably, has no wind (see Figure 6, below).[43] Currently, MISO operates one of the largest energy and operating reserve markets, with annual gross transactions of $22 billion.[44] MISO and SPP are in the Eastern Interconnection and share a common border.

SPP is a Regional Transmission Organization (RTO), a BA and a RC that operates a 552,885-square-mile area that includes all or portions of 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.[45] SPP operates 70,025 miles of transmission lines, and experienced its highest peak load of approximately 51,037 MW on July 28, 2021.[46] SPP's generating fleet is 38.5 percent (nameplate) natural gas, 29 percent wind, and 24.3 percent coal. However, coal accounts for the majority of the generated energy with 38.6 percent of the total, while wind and natural gas produce about 29.5 percent and 22.7 percent respectively.[47] SPP's integrated marketplace includes a day-ahead market with transmission congestion rights, a reliability unit commitment process, a real-time balancing market, and the incorporation of price-based operating reserve procurement.[48]

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[38] ERCOT Factsheet, February 2021, http://www.ercot.com/content/wcm/lists/219736/ERCOT_Fact_Sheet_2.12.21.pdf
[39] Press Release, Record electric demand expected this summer, http://www.ercot.com/news/releases/show/230649 (May 6, 2021).
[40] ERCOT, Qualified Scheduling Entities, http://www.ercot.com/services/rq/qse
[41] MISO also serves as a Planning Authority/Planning Coordinator, and Transmission Operator. SPP also serves as a Planning Authority/Planning Coordinator.
[42] MISO Corporate Fact Sheet, https://www.misoenergy.org/about/media-center/corporate-fact-sheet/
[43] *Id.*
[44] *Id.*
[45] SPP Fact Sheet https://www.spp.org/about-us/fast-facts/
[46] *Id.*
[47] *Id.*
[48] *Id.*

The following Figure 6 depicts the installed capacity[49] of generation resources by fuel type at the time of the Event. Natural gas-fired generation comprises the largest proportion of the generator fleets in all three footprints within the Event Area.

Figure 6: Installed Generation Capacity (MW) by Fuel Type

Fuel	ERCOT		SPP		MISO South	
Type	MW	Percent	MW	Percent	MW	Percent
Coal	14,703	11.9%	22,899	24.3%	7,221	17.2%
Natural Gas	64,202	52.2%	36,310	38.5%	25,364	60.6%
Nuclear	5,268	4.3%	2,061	2.2%	5,346	12.8%
Other	1,268	1.0%	5,115	5.4%	3,791	9.1%
Solar	6,202	5.0%	235	0.2%	143	0.3%
Wind	31,414	25.5%	27,612	29.3%	---	---
TOTAL MW	123,057		94,232		41,865	

3. Interconnections Between Affected Entities and Other Parts of the Electric Grid

ERCOT operates as a functionally separate interconnection (as shown in Figure 7 below), although it has four asynchronous ties with other interconnections. There are two Direct Current (DC) transmission tie lines[50] between ERCOT and the Eastern Interconnection through SPP: The North Tie, and the East Tie.[51]

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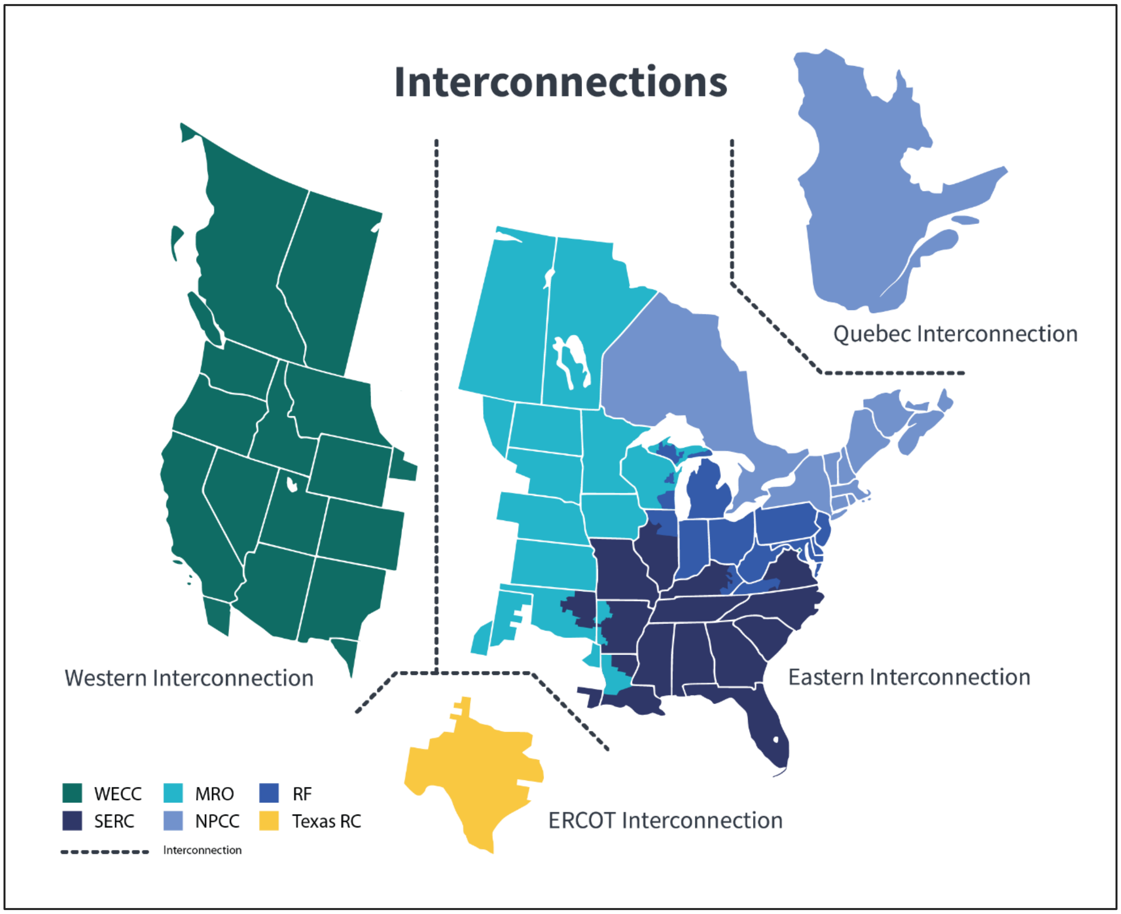
49 Installed or nameplate capacity differs from effective (also known as accredited capacity, especially for renewable resources such as wind and solar). Installed capacity is the total maximum capacity of the generating unit, whereas effective capacity takes into account forecasted weather, or temporary limitations for thermal units, to predict the percentage of the unit's capacity that will be available for a given day.

50 For DC transmission lines, the flow of power is controlled (i.e., scheduled), rather than flowing continuously as on synchronous ties.

51 ERCOT DC Tie Operations Document, Version 3, July 31, 2020, Section 1.3.

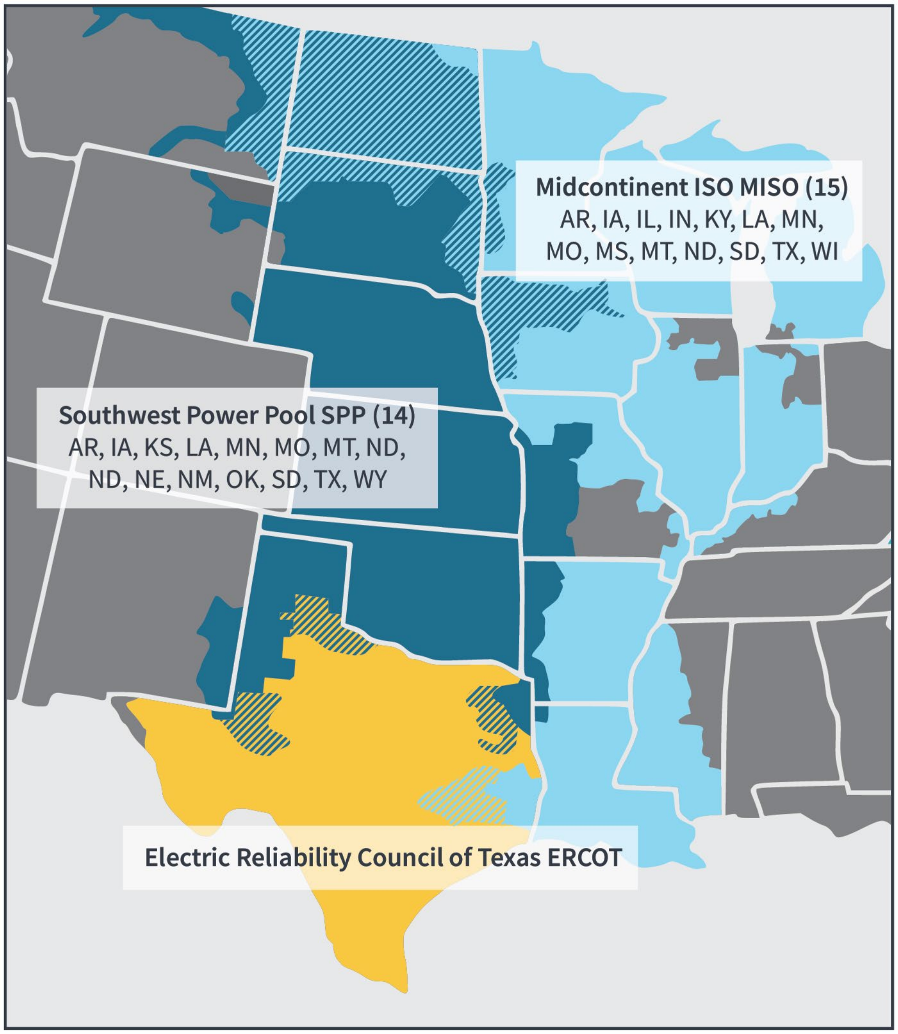
Figure 7: Electric Interconnections Map



In addition, there are two DC ties between ERCOT and Mexico's Grid Operator CENACE: The Laredo Variable Frequency Tie, and the Railroad Tie.[52] The maximum amount of energy that can be simultaneously imported on all of the ties into ERCOT is 1,220 MW, with 820 MW of that via the North and East Ties to the Eastern Interconnection.[53] SPP is bound to the west and south by DC ties that electrically separate the Eastern Interconnection from the Western Interconnection (seven DC tie lines) and ERCOT (two DC tie lines). MISO and SPP's common border, or seam, is shown in Figure 8, below.

[52] *Id.*
[53] *Id.*, Figure 1.3.

Figure 8: MISO and SPP Regional Transmission Organization Footprints



SPP's footprint is located at the westernmost edge of the Eastern Interconnection. SPP's tie-line capacity is predominantly with the MISO BA, and is far more extensive than ERCOT's DC tie-line capacity with SPP. SPP has a strong network of alternating current (AC) transmission tie-lines with MISO and other BAs east of its footprint, which allowed power to be imported from those BAs. Figure 9 shows the extent of tie-lines, by voltage level, between MISO and SPP.

Figure 9: Transmission Tie Lines Between MISO and SPP BAs

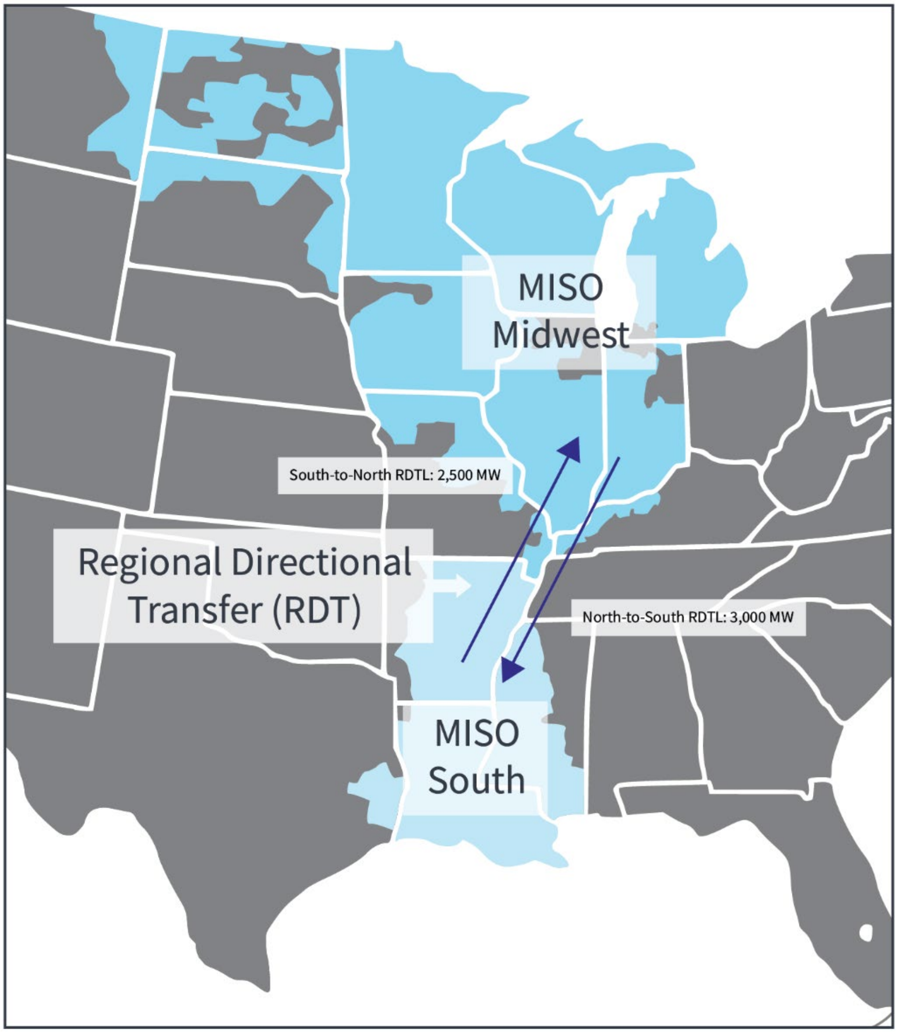
Voltage Level (kV)	Number of Tie-lines between MISO and SPP
69	85
115	30
138	5
161	41
230	13
345	16
500	3
Total	193

SPP's and MISO's transmission tie line connectivity is such that if large amounts of power (e.g., several thousand MW) need to be imported into or exported between SPP and other BAs in the eastern portion of the Eastern Interconnection (i.e., east-to-west or west-to-east directions), the power transfer flow is primarily through MISO's transmission system, and actual transfer capability is dependent on system conditions.[54] Similar to having many tie lines with SPP, MISO has 263 AC transmission tie lines to other BAs located within the Eastern Interconnection (e.g., PJM Interconnection LLC (PJM), Tennessee Valley Authority (TVA), Southern Company Services, Inc. – Trans).

MISO and SPP are parties to a Joint Operating Agreement designed to address power flows and improve operations along their seam. MISO has two regions within its BA area, joined by a single firm transmission path: MISO Midwest, to the north, and MISO South. As illustrated in Figure 10 below, MISO limits the amount of power it transfers intra-market, referred to as its Regional Directional Transfer Limit (RDTL), under an agreement with SPP and other six other BAs, to 3,000 MW from north-to-south (1,000 MW firm and 2,000 MW non-firm, as-available) and 2,500 MW from south-to-north (1,000 MW firm and 1,500 MW non-firm, as-available).

[54] While the total AC tie line capacity, calculated by adding the total capacity of all tie lines between the BAs at issue, may indicate a large transfer capacity, the actual ability to transfer power will be dependent on system conditions at the time of transfer, including ambient temperatures, generation outages and dispatch, transmission outages and derates, all of which drive actual power flows on transmission lines and can limit available transfer capability.

Figure 10: MISO Midwest to MISO South Intra-Market Regional Directional Transfers (RDT) and Associated Regional Directional Transfer Limits (RDTL)



C. Background on Preparation for Winter Peak Operations

1. Generation and Natural Gas Facilities' Preparedness

In the northern regions of the U.S., most energy production facilities are designed and constructed with the boilers, turbines/generators, and certain ancillary equipment housed in one or more enclosed buildings. In the colder months, heat radiating from boilers, other generation equipment, and supplemental heaters can generally maintain temperatures at a high enough level to prevent freezing. Enclosed areas are generally designed and constructed with fresh air inlets and roof-mounted exhaust ventilators for cooling during hot weather.

In the southern U.S., many generation facilities are designed and constructed without enclosed building structures, leaving the boilers, turbine/generators, and other ancillary systems exposed, in order to avoid excessive heat buildup. In the colder months, when temperatures may fall below freezing, these facilities are at risk of experiencing freezing issues.

Other energy production facilities are also at risk of being impacted by cold weather, including wind turbine generators, solar resources, and natural gas infrastructure. At natural gas production facilities, steps need to be taken to avoid wellhead "freeze-offs." Natural gas wells produce fluids containing water in addition to natural gas, which need to be transported through flowlines (pipes) at each well facility for storage and processing. When temperatures fall below freezing, fluid-handling equipment can experience freezing issues and potentially halt the production of natural gas.

Regardless of their location in the U.S., owners and operators of generating units and natural gas infrastructure facilities typically implement specific freeze protection or "winterization" plans for their facilities to function during extreme cold ambient temperature and weather conditions experienced at their locations. For exposed units in the southern U.S. and some natural gas infrastructure, winterization may involve a combination of permanent heated enclosures to protect equipment from cold, heat tracing, insulation, wind breaks, temporary or permanently-installed heating equipment, and other weather protection measures.[55]

Proper training of energy production facility operators on the facility's winterization plan is critical to ensure they will be prepared to take necessary actions before and during extreme cold weather events. At a minimum, training should include all operators annually reviewing site-specific winterization procedures. Less-experienced operators could be asked to perform the facility's cold weather checklist with more- experienced operators. Some entities conduct "lessons learned" exercises following major weather events, including severe cold weather events. As part of a lessons learned exercise, an entity would review its performance during the severe weather event, determine root causes of any weather-related problems, and develop additional best practices for similar events in the future. In many cases, entities incorporated the takeaways from those exercises into their winterization procedures. Some entities consider best practices from neighboring facilities or industry partners to keep their winterization plans comprehensive and up-to-date.

[55] Other more specific freeze-protection measures are discussed in sections III.A.3 and III.A.5, and Recommendation 6 (Natural gas freeze protection measures).

2. Grid Operations Entities' Seasonal Preparedness

a. Winter Season Reliability Assessments

Electric grid entities such as BAs and PCs typically perform seasonal reliability assessments in advance of each winter to determine available generation reserves during winter peak conditions. The assessments included forecast peak loads, generation capacity and projected reserves.

Peak load forecasts. Entities typically produce a 50/50 peak load forecast[56] for the upcoming winter season, which is based on quantitative analysis of data and assumptions, including but not limited to, historical winter peak load data and associated weather conditions, and economic factors. Many entities also produce a 90/10 peak load forecast,[57] which, similar to the 50/50 forecast, is based on quantitative analysis of historical data. Both forecasts are influenced by the historical actual peak loads that are used as inputs to their statistical analyses.

Expected generation capacity. Based on individual generating unit and other resource capacities (e.g., demand response, battery storage, etc.) that are expected to be available during winter peak conditions, entities determine the total anticipated resources they expect to be available to meet the forecast winter peak load. Data and assumptions typically include any expected seasonal capacity derates, and for intermittent resources (e.g., wind, solar resources), entities calculate an "expected" capacity. For example, the expected capacity for a 100 MW wind generation facility may be 20 MW, based on the variability of wind during the winter peak.

Projected reserves for peak conditions. Winter assessments typically account for generating unit scheduled/planned outages expected to occur during winter peak load, as well as an estimated amount of unplanned generation outages. The projected available resource capacity is used to calculate projected resource reserves above the 50/50 and 90/10 winter peak load forecasts, or whether there will be an expected shortfall.

The outputs of these assessments are typically provided in the form of reports that are presented in the fall for the entities' own use (e.g., RTO/ISO) and may be shared with companies within the BA footprint or that are RTO/ISO members. The reports are used to assist BA operations staff in preparing for the winter and for training for the upcoming winter season. In addition, data from the winter assessment, such as the 50/50 peak load forecasts and predicted reserve margins, are provided to NERC for development of its winter reliability assessment reports (WRA). NERC's WRA report identifies, assesses, and reports on areas of concern regarding the reliability of the North American BES for the upcoming winter season, including reporting anticipated resource adequacy reserve margins for regional operating areas (e.g., ERCOT, MISO and SPP). NERC's reports are made publicly available and are widely referred to by industry and policymakers.

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[56] A 50/50 peak load forecast is based on a 50 percent chance that the actual system peak load will exceed the forecasted value.

[57] A 90/10 peak load forecast is based on a 10 percent chance that the actual system peak load will exceed the forecasted value.

Probabilistic approach to assess demand and resources. NERC also uses operational risk analysis as part of its seasonal assessment. Operational risk analysis provides an approach for determining reliability impacts from certain scenarios and understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity—such as reductions for typical generation outages/derates and additions that represent the quantified capacity from operational measures, if any, that are available during scarcity conditions (e.g., emergency maximum generation available). The effects from low-probability events are also considered. In addition, some Regions calculate seasonal probabilistic indices, such as loss of load expectation (LOLE), loss of load hours (LOLH), and expected unserved energy (EUE) that represent the most up-to-date studies on resource adequacy risk.

b. ERCOT's, MISO's and SPP's Winter 2020/2021 Seasonal Assessments

ERCOT, SPP and MISO performed seasonal assessments in advance of the 2020/2021 winter to determine available generation reserves during winter peak conditions. The assessments included forecast peak loads, generation capacity and projected reserves. Figure 11, below, provides a summary of peak load forecasts versus actual peak loads during the Event.

Figure 11: Winter 2020/2021 Peak Load Forecasts and Actual Loads for Event Area

		ERCOT	SPP	MISO South
Previous All-Time Winter Peak/Date:		65,750 1/17/2018	43,584 1/17/2018	32,100 1/17/2018
2020/2021 50/50 Forecast Winter Peak:		57,699	42,062[58]	28,459
2020/2021 90/10 Forecast Winter Peak:		67,208	44,452[59]	29,562
Feb. 2021 Actual Peak Load/ Date of Occurrence:		69,871 2/14/2021	43,661[60] 2/15/2021	29,946 2/15/2021
Feb. 2021 Estimated Peak Load w/o load management/ Date of Occurrence:		76,819 2/15/2021	47,000[61] 2/16/2021	30,977 2/15/2021
% Actual Peak Was Above Forecasts	**50/50:**	20.0%	3.8%	5.2%
	90/10:	2.9%	-1.8%	1.3%
% Estimated Peak Was Above Forecasts	**50/50:**	33.1%	11.7%	8.9%
	90/10:	14.3%	5.7%	4.8%

ERCOT Load Forecasts and Projected Reserves. ERCOT's Winter 2020/2021 Seasonal Assessment of Resource Adequacy (SARA) focused on the availability of sufficient operating reserves to avoid emergency actions such as deployment of voluntary load reduction resources.[62] Based on its winter SARA, ERCOT believed that it could meet its projected winter peak demand of 57,699 MW with available generation and imports (based on normal weather conditions). ERCOT's extreme winter forecast was 67,208 MW, higher than its previous all-time winter peak demand record of 65,750 MW, set on January 17, 2018. To meet that extreme peak demand, ERCOT had projected resource capacity of 82,513 MW, leaving reserves of only 1,352 MW, considering a 90/10 extreme load scenario combined with additional generation reductions of 13,953 MW.[63] See Figure 12 below, which summarizes ERCOT's projected SARA for the 2020/2021 winter season. It uses

[58] From NERC 2020-2021 Winter Reliability Assessment, without demand response. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf
[59] *Id.* (SPP's 90/10 is calculated for NERC by increasing the 50/50 by 5 percent).
[60] Peak load may have been affected by the impacts of conservation efforts (e.g., SPP EEA 2 conservation declarations).
[61] SPP set a new winter peak load of 43,661 MW the morning of February 15 and likely would have reached a wintertime peak of 47,000 MW [on February 16] if not for conservation and curtailments. *See*: https://spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf
[62] ERCOT releases its SARA one to two months before each season. ERCOT'S SARA is intended to illustrate the range of resource adequacy outcomes that might occur.
[63] This generation outage figure represented the 95th percentile of expected generation outages, according to ERCOT.

an operating reserve threshold of 2,300 MW to indicate the risk that an EEA 1 might be triggered during the time of the forecasted seasonal peak load. This threshold level was intended to be roughly analogous to the 2,300 MW Physical Responsive Capability threshold for EEA 1.[64]

Figure 12: ERCOT Winter 2020/2021 Seasonal Assessment of Resource Adequacy[65]

ERCOT Winter 2020/2021 SARA: Range of Potential Risks

	Forecasted Season Peak Load	Extreme Peak Load / Typical Generation Outages During Extreme Peak Load	Forecasted Season Peak Load / Extreme Low Wind Output	Extreme Peak Load / Extreme Generation Outages During Extreme Peak Load
Total Resources, MW	82,513	82,513	82,513	82,513
Forecasted Season Peak Load	57,699	57,699	57,699	57,699
Seasonal Load Adjustment	-	9,509	-	9,509
Typical Maintenance Outages, Thermal	4,074	4,074	4,074	4,074
Typical Forced Outages, Thermal	4,542	5,339	4,542	5,339
95th Percentile Forced Outages, Thermal	-	-	-	4,540
Low Wind Output Adjustment	-	-	5,279	-
[d] Total Uses of Reserve Capacity	8,616	18,922	13,895	23,462
[e] Capacity Available for Operating Reserves, Normal Operating Conditions (c-d), MW. Less than 2,300 MW indicates risk of EEA1	**16,198**	**5,892**	**10,919**	**1,352**

As shown in Figure 12, in addition to the "Forecasted Season Peak Load" base scenario, ERCOT develops several other scenarios shown in the adjacent table columns by varying the values of various load forecast and resource availability parameters. Although ERCOT seemingly had a generous reserve margin going into the winter of 2020/2021, its reserve margins were slimmer when

64 Physical Responsive Capability is a real-time measure of resources that can quickly respond to system disturbances. In contrast, the SARA operating reserve reflects additional capacity assumed to be available before energy emergency procedures are initiated, such as from resources qualified to provide non-spinning reserves. The amount of operating reserves available may increase relative to what is included in the SARA if the market responds to wholesale market price increases and anticipated capacity scarcity conditions. Given these considerations, ERCOT believes that the 2,300 MW reserve capacity threshold is a reasonable indicator for the risk of EEAs, given the uncertainties in predicting system conditions months in advance.

65 http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.pdf.

ERCOT accounted for additional risks. Under the extremely low wind generation output scenario,[66] ERCOT expected to lose about 5,279 MW of wind generation, lowering the expected wind forecast to 1,791 MW and leaving its reserves at 10,919 MW. When adjusted for extreme peak load and typical outages,[67] ERCOT's reserves were even lower, estimated at 5,892 MW. ERCOT's most extreme scenario, adjusting for extreme peak demand and extreme outages (but not including low wind conditions), indicated that ERCOT would have only 1,352 MW of operating reserve capacity if those conditions materialized.[68] The variation in these parameters is based on historic ranges of the parameter values or known changes expected in the near-term. The SARA is not intended to predict the likelihood of any of these scenario outcomes.

ERCOT does not classify flows across its DC ties as firm capacity because such flows are scheduled as day-ahead energy transactions. However, in its SARA, ERCOT assumed an expected amount of net imports based on the average amount of net imports reported during winter 2013/2014 EEA intervals. ERCOT's reflected demand response based on the peak demand forecast during the period from January 2015 to August 2020. The demand response impact is embedded in the forecast and is not available as a separate forecast component, and there are no assumptions regarding future incremental changes to demand response impacts. Because ERCOT's SARA is intended to show the risk of entering EEA 1, load resources are not accounted for, since they are only available after an EEA is declared.

MISO Load Forecasts and Projected Reserves. MISO performs seasonal load assessments for its entire footprint and for the North/Central and South sub-areas. MISO 90/10 zonal load forecasts are developed by applying a Load Forecast Uncertainty value, calculated at the zonal level, to the LSE-submitted 50/50 load forecasts for each Local Resource Zone. The Load Forecast Uncertainty values are based on the actual highest summer peak load day for each of the past 30 years.

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[66] Both maintenance and forced outages for wind and solar are accounted for in the peak average capacity contribution values, based on historical wind and solar capacity factors for seasonal peak load hours. At the time of the forecast, ERCOT had a wind fleet with nameplate capacity of approximately 24,962 MW. The total forecast wind generation (existing and planned) in the SARA was 7,070 MW. Existing wind generation reflected in the SARA was 6,142 MW (divided into three categories: 1,480 MW of coastal wind resources (based on 43 percent of installed capacity); 1,411 MW of panhandle wind resources (based on 32 percent of installed capacity), and 3,251 MW of other wind resources (based on 19 percent of installed capacity)). ERCOT's SARA also included an estimate for planned wind resources of 928 MW with a nameplate capacity of 3,794 MW (based on in-service dates provided by developers) (divided into two categories: 371 MW of planned coastal wind and 557 MW of planned other wind).

[67] ERCOT's reported generation capacities include (1) winter net maximum sustained ratings, and (2) winter peak average capacity contributions, the methodologies for which are documented in ERCOT Nodal Protocols (Section 3.2.6.2.2). Generation capacities reflect what is expected to be available at the time of the winter peak load. University of Texas at Austin Energy Institute, *The Timeline and Events of the 2021 Texas Electric Grid Blackouts* (hereafter UT Report) (July 2021) at 15, Fig. 2a. UTAustin_(2021)_EventsFebruary2021TexasBlackout_(002)FINAL_07_12_21.pdf The SARA reports capacity available for operating reserves, which accounts for scenario variations in forecasted peak load, forced and maintenance outages, and wind output. Thermal and hydro forced outage scenario assumptions are based on the historical average of planned outages for December through February weekdays, hours ending 7 a.m. - 10 a.m., for the last three winter seasons (2017/18, 2018/19, and 2019/20), which assumed total maintenance and forced outages of 8,616 MW.

[68] ERCOT's SARA did not include a scenario with low wind, extreme load and thermal outages; the result would have shown a capacity deficit of -3927 MW to serve load and reserve needs.

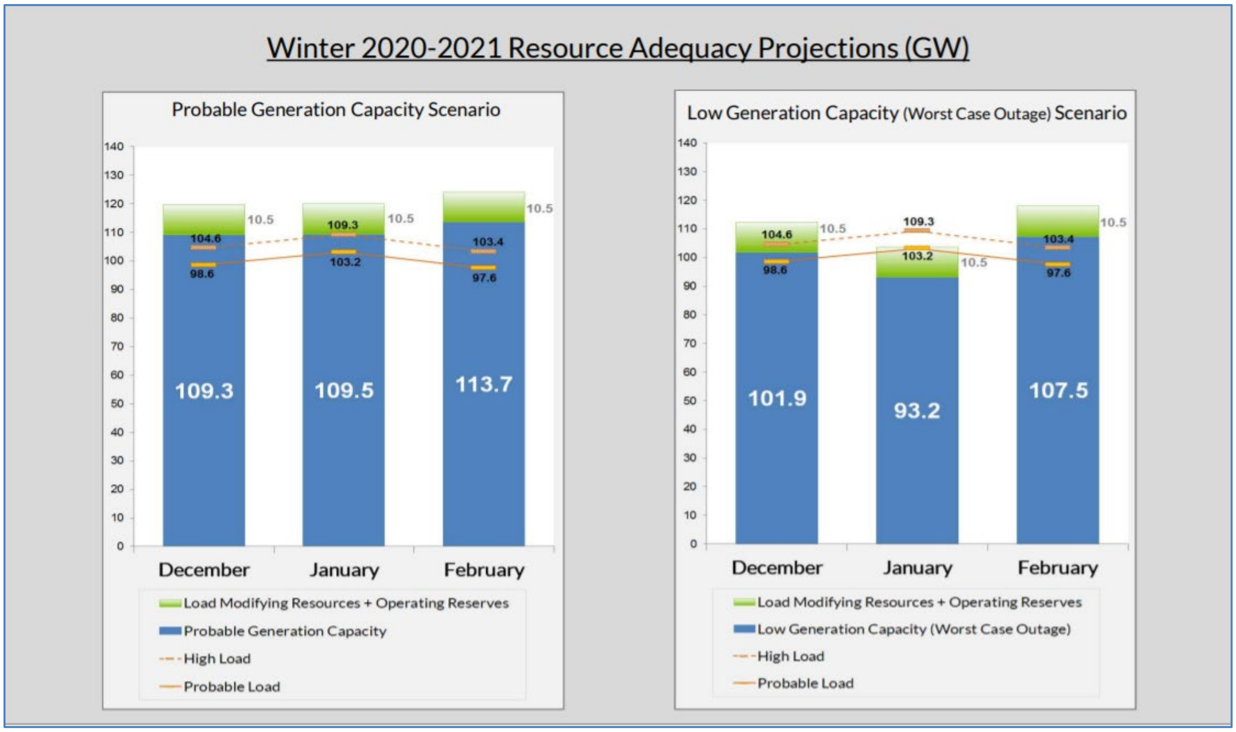
Planned, scheduled, and forced outages are included in the reserve values by subtracting the historical planned plus forced generation outage totals (sourced from GADS)[69] from monthly projected available capacity. MISO calculates the probable generation capacity scenario by taking the five-year average of planned plus forced monthly generation outages during the single-highest monthly (December through February) peak demand days for the last five years. MISO calculates the low generation capacity scenario by using the single highest amount of planned plus forced generation outages for each month evaluated in a season for the last five years (e.g., December to February 2016 to 2020). MISO includes firm imports offered into the Planning Resource Auction in its winter capacity totals and nets out MISO resources with capacity arrangements outside of MISO. MISO performs steady state AC contingency analysis, and thermal, voltage stability and phase angle analysis during energy transfer simulations.

MISO did not anticipate resource availability issues for winter 2020/2021 based on prior winter readiness and fuel deliverability surveys anticipating robust fuel deliverability and multiple measures taken to prepare units for potential severe winter weather. For MISO South, it forecast demand under the 50/50 scenario of 28,459 MW, and 29,562 MW under the 90/10 extreme conditions scenario.

Based on MISO's winter assessment, Figure 13 below provides a summary of its projected capacity and reserves for the 2020/2021 winter season. MISO does not perform a separate seasonal assessment for its MISO South region.

[69] Generating Availability Data System (GADS) is a mandatory industry program for tracking information about outages of conventional generating units that are 20 MW and larger. Generating Availability Data System (GADS) (nerc.com))

Figure 13: MISO Winter 2020-2021 Resource Adequacy Projections (GW)[70]



For its seasonal resource assessments, MISO produces two scenarios: (1) a probable generation capacity scenario and (2) a low generation capacity scenario (see Figure 13, above). The difference between these two scenarios is the amount of cumulative historical generation outages that are subtracted from expected seasonal capacity to arrive at a monthly available capacity projection. In the probable generation capacity scenario, MISO uses the five-year average amount of cumulative monthly generation outages that occurred during the single highest monthly peak demand days from each of the five most recent years. For the low generation capacity scenario, MISO uses the single highest amount of cumulative generation outages during the most recent five years for each month evaluated in a season. For its 90/10 Load/Low Generation Capacity Scenario, MISO projected a 2020/2021 winter peak reserves deficit of 5,591 MW. Like ERCOT, MISO projected that adequate resources would likely be available to meet the expected winter demand forecast but recognized that winter scenarios with high generation outages and high demand could drive operational challenges.[71]

SPP Load Forecast and Projected Reserves. SPP performs seasonal load assessments for its entire footprint and for 22 sub-areas. SPP relies on peak load forecasts submitted by the transmission owners and load-serving members, which are responsible for calculating load forecasts

[70] https://cdn.misoenergy.org/20201027%20Winter%20Readiness%20Workshop%20Presentation486841.pdf at page 42.
[71] *2020-2021 MISO Winter Readiness Forum*, (Oct. 27, 2020), 42, https://cdn.misoenergy.org/20201027%20Winter%20Readiness%20Workshop%20Presentation486841.pdf

and submitting the forecasts to SPP according to Reliability Standard MOD-032. To produce its 50/50 scenario peak load forecast, SPP uses non-coincident peak load forecasts submitted and applies outages to the models, including those scheduled and other systematically selected unscheduled transmission and generation outages (to account for future system outage uncertainties). SPP performed thermal and voltage contingency analysis on the SPP RC footprint. Additionally, SPP performed voltage security assessment scenarios for areas deemed susceptible to voltage issues.

As part of its seasonal assessment, SPP performs transfer studies to stress its system. The transfer studies are internal to SPP; it does not currently perform any interregional studies. However, SPP and MISO do regularly share the results of their internal studies with each other. SPP considers MISO-submitted data (e.g., load, transmission and generation outages and net scheduled interchange) in its outage coordination, operational planning analyses and next-day studies.

In its seasonal assessment for winter 2020/2021, SPP stated that "the operating capacity for the 2020-21 winter season is expected to be sufficient for normal operating conditions; however, under severe conditions, localized or brief capacity constraints may occur expected to have resources sufficient to meet its expected load." SPP expected a 42,062 MW peak load under its 50/50 scenario. In SPP's winter 2020-21 transmission assessment, operations within the SPP RC and eastern RC area footprints were expected to be normal given the expected scheduled outages.

SPP provided inputs into NERC's 2020/2021 Winter Reliability Assessment for reserve margin projections. Figure 14, below lists SPP's anticipated reserve margin data, along with ERCOT's and MISO's data that were submitted as inputs to NERC's report.

Figure 14: Publicly-Reported Reserve Margins for Winter 2020/2021 (SPP, ERCOT and MISO)[72]

Data From NERC 2020-2021 Winter Reliability Assessment (November 2020)			
	ERCOT	SPP	MISO
Demand, Resource, and Reserve Margins	2020–2021 WRA	2020–2021 WRA	2020–2021 WRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Total Internal Demand (50/50)	57,699	42,062	103,167
Demand Response Available	2,764	252	4,536
Net Internal Demand	54,935	41,811	98,631
Resource Projections	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Existing-Certain Capacity	80,715	66,277	144,736
Tier 1 Planned Capacity	1,359	298	574
Net Firm Capacity Transfers	210	(36)	1,405
Anticipated Resources	82,284	66,539	146,715
Existing-Other Capacity	614	-	6,390
Prospective Resources	82,898	66,539	153,557
Resource Projections	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	49.8%	59.1%	48.8%
Prospective Reserve Margin	50.9%	59.1%	55.7%
Reference Margin Level	13.8%	15.3%	18.0%
Extreme Winter Peak Demand (MW)	67,200	44,200	109,900

ERCOT, SPP and MISO anticipated winter reserve margins of 49.8 percent, 59.1 percent, and 48.8[73] percent, respectively, in the NERC winter reliability assessment. Planning reserve margins are designed to assess the overall capacity supply of the system and do not necessarily predict how the system will perform on a given day.

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[72] *See* NERC 2020/2021 WRA (November 2020), at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf.

[73] This winter reserve margin is for the entire MISO footprint. MISO does not calculate a separate winter reserve margin for MISO South.

c. Generator workshops, fuel surveys, and site visits by BAs

ERCOT. ERCOT initiated a winter weatherization spot check program during the 2011/2012 winter season, following the February 2011 cold weather event. From winter 2011/2012 until winter 2019/2020, ERCOT and Texas RE staff typically visited 75-80 generating units per year to assess their readiness for the upcoming winter season and suggest potential improvements. Texas RE calls its visits "site visits," and although ERCOT and Texas RE normally visit generating units jointly, the purpose of their visits is slightly different, as discussed below. For winter 2020-2021, due to COVID-19 Pandemic concerns, the program was conducted remotely.

ERCOT and Texas RE attempted to visit larger coal and gas-fired generation facilities at least once every three years and prioritized the units based on issues experienced during prior winter seasons and the need to follow up on recommendations from previous site visits.[74] ERCOT focused its spot checks on Public Utility Commission of Texas rules and ERCOT Nodal Protocols, and to standardize its review, ERCOT developed a comprehensive checklist of items to evaluate. Texas RE focused its site visits on recommendations from the 2011 Southwest cold weather report, the NERC Generating Unit Winter Weather Readiness Reliability Guideline and information gathered from NERC's Generating Availability Data System (GADS).[75] ERCOT's checklist included questions related to winterization and maintenance, and improvements to the winterization plan based on previous winter lessons learned and previous site visit recommendations. The site visit team reviewed each unit's winter weatherization plan and its procedures for cold weather events. If the unit experienced freeze issues the previous winter, the team physically examined the element(s) which froze or forced a trip and reviewed the measures that the generating unit took to protect the element from freezing again. The team also reviewed maintenance records for freeze protection measures such as heat tracing, insulation, and instrument air systems, as well as for dual-fuel units. At the end of each site visit, ERCOT and Texas RE staff provided a summary of comments, best practices, or recommendations for improving the generating unit's winterization activities. If deficiencies were identified, ERCOT or Texas RE staff scheduled a follow-up visit before the next winter.

In addition to the winter weatherization site visit program, ERCOT and Texas RE hosted a winter preparation workshop in September of each year before 2020. The workshops focused on the common causes of outages due to cold weather from the previous winter, review of the upcoming winter weather forecast, review of common issues and recommendations from the previous year's site visits, and presentations from generating companies on improvements made and best practices. Prior to the Event, ERCOT had seen reductions in the MW of generating units tripped or derated due to frozen instrumentation during cold weather events, as seen in Figure 15, below.

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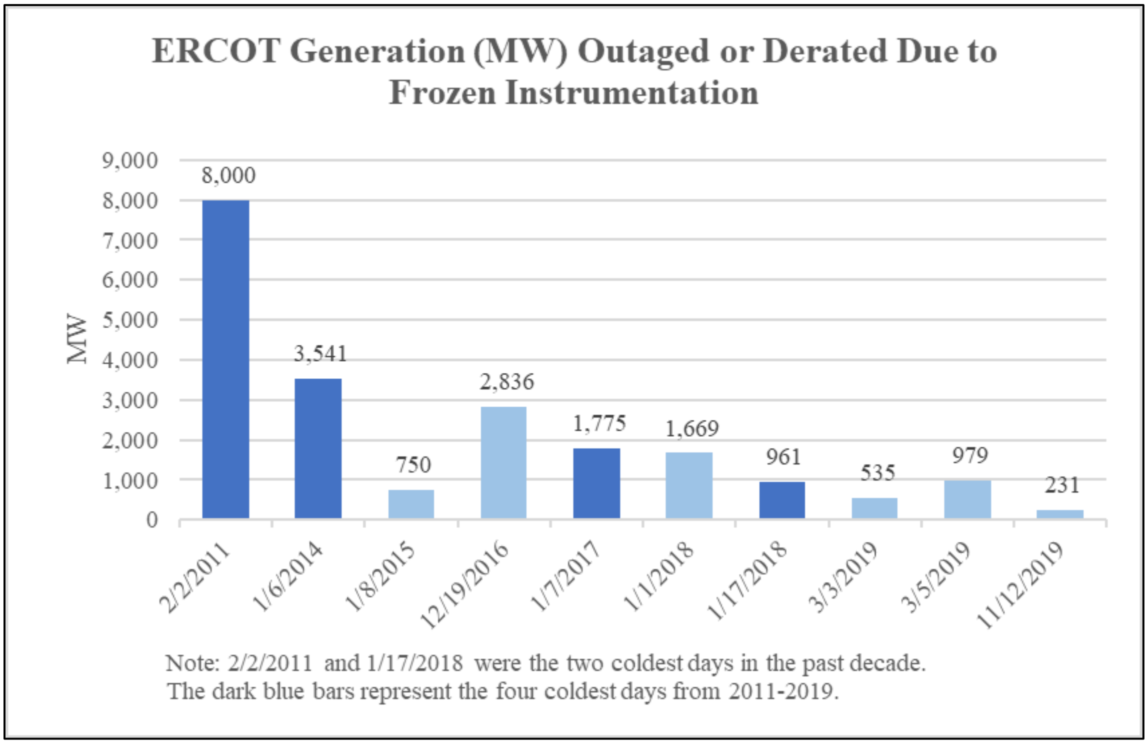
[74] Each visit is both an ERCOT spot check and a Texas RE site visit but will hereafter be referred to as the site visit except to describe the focus of each entity.

[75] Reliability Guideline Generating Unit Winter Weather Readiness – Current Industry Practices – Version 3, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v3_Final.pdf#search=winter%20reliability%20guideline(hereafter, Reliability Guideline).

Figure 15: ERCOT Generation (MW) Outaged or Derated Due to Frozen Instrumentation



ERCOT's winter weatherization spot check program has continued to evolve since its inception, learning lessons from various events. After the 2014 Polar Vortex event, knowledge and identification of facility critical components became a point of emphasis, including maintenance of heat tracing and insulation systems associated with those critical components, as well as tracking heat tracing test records. After the January 2018 event, ERCOT prioritized incorporating instrument air systems into the weatherization programs.

ERCOT and Texas RE staff recognized that their programs could still be improved. For example, staff can only assess whether the generating unit is implementing or executing its winterization plan but find it difficult to assess the quality of the plan, unless the unit experienced freezing incidents during a previous winter event. Generating units are not currently required to weatherize to a common ambient temperature design[76] or for the accelerated cooling effect of wind (in fact many GOs did not know the design temperature for their facilities). Specific knowledge of the insulation and heat tracing systems for a facility is critical as different types of heat trace cable may require different testing and maintenance methods.

ERCOT also required GOs and GOPs to submit an annual declaration, stating that it has or will complete all weather preparations required by its weatherization plan for equipment critical to the

[76] *See* Recommendation 1.f. (recommending that the Reliability Standards be revised to require GOs to retrofit existing generating units, or design any new units, to operate to specified ambient temperatures, wind, and precipitation).

reliable operation of the generating unit.[77] Declarations are due between November 1 and December 1 of each year.[78] This process is designed to ensure that all generating units have followed their weatherization plans. Ninety-six percent (147 of 153) of GOs/GOPs surveyed within ERCOT had submitted a declaration of completion of preparation for winter 2020/2021. Seven entities reported outstanding winter preparations for 18 natural gas-fired generating units, including protections as critical as heat trace repair and replacement, wind breaks, and insulation of transmitter sensing lines, that were not expected to be completed until as late as December 23, 2020.[79] Given that GOs/GOPs can delay such critical preparations until well after the onset of cold weather, it appears that there is no meaningful follow-up process when entities fail to complete their winter preparations by the December 1 deadline.

Whether the declarations are effective at achieving winter preparations is debatable. The required declarations are not used to measure the generating unit's performance; even if the weatherization plans are followed, the declaration does not guarantee a generating unit will remain fully operational throughout the winter season or during extreme weather conditions.

MISO and SPP. Unlike ERCOT, neither MISO nor SPP conduct site visits of generating unit winter preparations. SPP conducts a summer preparedness workshop in the spring and a winter preparedness workshop in the fall, which GOs/GOPs as well as TOPs can attend. Its annual winter preparedness workshop includes presentations on weather forecasts by meteorologists, seasonal assessments by the outage coordination team, critical communication types, the NERC Reliability Guidelines, and a tabletop discussion on business continuity. SPP held its winter 2020/2021 preparedness workshop on September 29, 2020.[80] Attendance is voluntary, and SPP has typically seen high participation rates. In the fall of 2019, SPP conducted a voluntary generating unit winter weather preparedness survey. The survey asked questions regarding winter preparation plans (especially for critical equipment), previous winter freeze issues, generating unit minimum temperature, experience below that temperature, generating unit winterization improvements, heat trace and insulation inspections, cold weather drills/training, start-up requirements, and alternate fuel sources. Most GOPs did not respond to the voluntary generation winter preparedness survey conducted by SPP, which also asked about fuel supply. SPP does not conduct a survey covering transmission winter preparedness, but SPP TOPs can participate in the winter preparedness workshop.

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[77] Required as part of ERCOT's Nodal Protocols, which outline the procedures and processes used by ERCOT and market participants for the orderly functioning of the ERCOT system and nodal market. http://www.ercot.com/mktrules/nprotocols. The Public Utility Commission of Texas (PUCT) recently revised its rules to require these declarations to be executed by the GO's highest-ranking officer with binding authority. 51840_101_1160359.PDF (texas.gov)

[78] *See* Section 3.21, Part (3) of ERCOT's Nodal Protocols.

[79] Of the four percent of the entities (six of 153) that did not submit a declaration, two are solar operators (500 MW capacity) that stated weatherization practices are not applicable to their facilities; two entities are new solar operators (250 MW capacity) that had not yet received the declaration from ERCOT, and two entities (100 MW gas/250 MW wind capacity) did not respond to this question.

[80] NERC 2020-2021 Winter Reliability Assessment, at 26, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf (Nov. 2020).

MISO reviewed recommendations from previous FERC-NERC joint reports on cold weather events to improve its winter readiness training. MISO conducted its winter 2020/2021 readiness forum on October 27, 2020. This workshop covered such topics as winter lessons learned and operations guidelines, extreme cold weather preparedness and procedures, winter 2019 maximum generation and turbine issues, generation and transmission assessments, and fuel surveys. MISO shared its October 23, 2018 Winterization Guideline and presentations on "Generation Performance During Severe Cold Temperatures" and its 2020/2021 Winter Resource Assessment. MISO's 2020 generator winterization survey had a 71 percent response rate, while its natural gas fuel survey response rate was 83 percent.[81] Participation in both surveys has improved between 2019 and 2020, and over 95 percent of the GOs/GOPs that responded to the survey said that they have a plan to prepare for winter 2020. However, updating winter preparation plans every winter is ideal and the majority had not updated their plans in the last three years. While 43 percent of MISO GOs/GOPs had made changes to their winterization plans in the past three years, only 36 percent of SPP and 27 percent of ERCOT GOs/GOPs had done so.[82]

d. Preparedness for Emergency Operations

RCs, BAs, TOPs and TOs typically perform load shed drills as part of their required emergency operations training.[83] TOPs have load shed procedures which cover both operator-controlled manual and automatic load shed. The Reliability Standards do not prohibit TOPs from using automatic load shed configured circuits (e.g., underfrequency load shed, undervoltage load shed circuits) for manual load shed, but do require TOPs to minimize the overlap of with automatic load shedding.[84]

[81] Forty-two percent reported that they have access to firm transportation and/or dual fuels, 39 percent reported a mix of firm and interruptible transportation, and 10 percent reported interruptible gas supply only.
[82] Examples of changes made to winterization plans included: upgrading or completely replacing existing freeze protection equipment; adding new heat tracing cables, control panels and instrument enclosures; increasing the number of enclosures built around critical equipment that had experienced freezing in years past; discussing lessons learned prior to and after the winter season; adding dew point monitoring to the air system; adding an additional hydrogen trailer onsite; and building cold weather shelters around instrument transmitters, instrument air dryers, instrument air compressors, vacuum pumps, and seal oil regulators, among other vulnerable equipment. Some of the most common changes made to winterization plans in the past three years are changes to annual weatherization checklists, and incorporating lessons learned from the previous winter, leading to a process of continuous improvement.
[83] Reliability Standard PER-005-2 – Operations Personnel Training, Requirement R4: Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES.
[84] EOP-011-1 - Emergency Operations, Requirements R1, 1.2.5 and Requirement R2, 2.2.8.

i. Manual and Automatic Load Shed Plans[85]

ERCOT. Transmission Operators in ERCOT are responsible for developing an emergency operations plan to mitigate operating emergencies,[86] which includes provisions for operator-controlled manual load shedding that minimizes the overlap with automatic load shedding[87] and is capable of being implemented in a timeframe adequate to mitigate the emergency.[88] Transmission Service Providers and Distribution Providers (DP) have the responsibility for determining exactly which circuits are to be disconnected during a load shed event.

Not all distribution circuits are eligible for manual or automatic load shedding. Some are protected due to the presence of so-called critical loads. Critical loads, within ERCOT, are "loads for which electric service is considered crucial for the protection or maintenance of public safety; including but not limited to hospitals, police stations, fire stations, critical water and wastewater facilities, and customers with special in-house life-sustaining equipment," and further identified by the Public Utility Commission of Texas (PUCT) as "military facilities, facilities necessary to restore the electric utility system, law enforcement organizations and facilities affecting public health, and communication facilities."[89] PUCT rules identify four classifications of customers as critical loads: (1) Critical Load Public Safety Customer; (2) Critical Load Industrial Customer; (3) Chronic Condition Residential Customer; and (4) Critical Care Residential Customer.[90] To be designated under the first two categories, the entity (e.g., a gas pipeline facility) must notify its Transmission and Delivery Utility (TDU), which reports to the PUCT annually the number of critical load customers for each customer class. BAs and RCs are not aware of potential critical loads, including natural gas infrastructure loads, that may impact generating units unless the critical load entity has notified its TDU.

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[85] All three BAs' and their TOPs' manual load shed plans were designed for implementing and rotating much smaller increments of firm load shed than the 20,000 MW of firm load shed ordered by ERCOT during the Event.

[86] NERC Standard EOP-011-1 Emergency Operations requires that each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area.

[87] There are generally two methods used for conducting automatic load shedding. Underfrequency Load Shedding (UFLS) is used to balance generation and load when a system event, such as the loss of a large generating unit or multiple generating units occurs, causing a significant drop in frequency throughout an interconnection or islanded area. The use of UFLS can be looked upon as an automatic response associated with a decline in frequency in order to rebalance the system. UFLS protection schemes, through the use of relays, take a stepped approach to opening designated breakers after specific frequency thresholds are passed in order to shed load and reverse declining system frequency. Typically, when the threshold is met, the trip occurs in 30 cycles (.5 seconds). The Reliability Standards PRC-006-5 and PRC-008-0 define UFLS requirements. Undervoltage Load Shedding (UVLS), which is very similar to UFLS, trips load offline to prevent or avoid voltage collapse scenarios which can lead to cascading outages, through the use of specific voltage settings - not frequency settings. When predetermined voltage levels and timing requirements are met, a signal is sent to open designated circuit breakers shedding load to improve system voltage. The NERC Standards PRC-010-2 and PRC-011-0 define UVLS requirements.

[88] ERCOT Nodal Operating Guides, at 8L-1, Section V (D).

[89] Public Utility Commission of Texas Rules, Chapter 25 Rules, Subchapter A , Section 25.5; ERCOT's Operating Guidelines, Chapter 4, Emergency Operations, Section 4.5.2.

[90] Public Utility Commission of Texas Rule 25.497 (16 Tex. Admin. Code § 25.497).

ERCOT requires that UFLS relays should be set to provide relief when specific frequency thresholds are met.[91] In the event of an underfrequency event, each TOP is required to provide load relief by shedding the required percentage of its Distribution Provider-DSP-connected load and transmission-level customer load using automatic underfrequency relays.[92] Twenty-five percent of the DP and TOP load within ERCOT should be equipped with UFLS. Specifically, ERCOT requires that at the frequency threshold of 59.3 Hz, at least five percent of the TO load should be shed; at 58.9 Hz, the amount of load shed increases to at least 15 percent, and at 58.5 Hz, the required load shed is at least 25 percent.[93] Prior to the peak load each summer, ERCOT surveys each TOP's compliance with the automatic load shedding requirements.[94]

DPs are required to ensure that loads equipped with underfrequency relays are dispersed geographically throughout the ERCOT region to minimize the impact of load shedding within a given geographical area. Customers equipped with underfrequency relays shall be dispersed without regard to which Load Serving Entity serves the customer. If a loss of load occurs due to the operation of underfrequency relays, a DP may rotate the physical load interrupted to minimize the duration of interruption experienced by individual customers or to restore the availability of underfrequency load-shedding capability. The initial total amount of underfrequency load shed cannot be decreased without the approval of ERCOT. TOPs, in coordination with DPs, are required to make every reasonable attempt to restore load, either by automatic or manual means, to preserve system integrity.[95]

ERCOT Nodal Protocols and NERC Reliability Standard PRC-024-2 (Generator Frequency and Voltage Protective Relay Settings) allow generating units to automatically trip offline, or automatically shut down and disconnect from the grid, if the grid frequency drops to 59.4 Hz or below for more than nine minutes. If generator underfrequency relays are installed and activated to trip the unit, these relays shall be set such that the automatic removal of individual generating units from ERCOT's system meets the following requirements, shown in Figure 16, below:[96]

91 ERCOT's Nodal Operating Guide, Section 2.6, at 2-36 (February 5, 2021).
92 *Id.* at 2-20.
93 *Id.*
94 *Id.* at 2-21.
95 *Id.* at 2-21.
96 *Id.* at 2-22.

Figure 16: ERCOT Generator Underfrequency Trip Setting Guideline

Frequency Range	Delay to Trip
Above 59.4 Hz	No automatic tripping (Continuous operation)
Above 58.4 Hz up to and including 59.4 Hz	Not less than 9 minutes
Above 58.0 Hz up to and including 58.4 Hz	Not less than 30 seconds
Above 57.5 Hz up to and including 58.0 Hz	Not less than 2 seconds
57.5 Hz or below	No time delay required

MISO. In MISO, Local Balancing Authorities (LBAs) are responsible for individual load shed programs and perform actual load sheds as directed by the MISO BA, including rotation of load and taking into account critical load identification. MISO requires the LBAs to maintain the minimum MISO-directed load shed at all times, until it directs load to be restored. Each individual LBA has internal procedures for their own specific load shed processes.

Most MISO TOs and DPs have a three-stage UFLS program initiated at 59.3, 59.0 and 58.7 Hz, shedding anywhere from 24 to 43 percent of their respective load. Other TOs and DPs have a five-step UFLS program initiated at 59.3, 59.0, 58.7, 58.5 and 58.3 Hz, shedding approximately 30 to 42 percent of their load. Additionally, there are several small municipal TOs and DPs that are expected to shed 100 percent of their load in one step.

SPP. SPP BA's Emergency Operating Plan requires its TOPs and DPs to have the capability to implement its firm load shedding plan "within a timeframe adequate to the emergency." SPP relies on the TOPs and DPs to manage their load shedding procedures and curtail their pro rata share of firm load.

In SPP, each UFLS entity (primarily TOPs, some DPs) with a total forecasted peak load in the SPP annual data request of more than 100 MW is required to develop and implement an automatic UFLS program that sheds a minimum of 10 percent of load at each UFLS step in accordance with the table containing frequency thresholds, as shown in Figure 17, below:

Figure 17: SPP Underfrequency Load Shed Frequency Thresholds

UFLS Step	Frequency (hertz)	Minimum accumulated load relief as percentage of forecasted peak Load (%)	Maximum accumulated load relief as percentage of forecasted peak Load (%)
1	59.3	10	25
2	59	20	35
3	58.7	30	45

Coordination with natural gas infrastructure by BAs. Within the SPP footprint, manual load shed plans and procedures for several TOPs and DPs contained steps and measures to minimize the potential of natural gas infrastructure of being used for firm load shed. Examples included identification of circuits supplying natural gas infrastructure as critical to protect from manual load shed, exclusion of sub-transmission and distribution circuits supplying natural gas infrastructure from the UFLS and manual load shed circuit lists within the manual and UFLS load shed procedures, and statements within the manual load shed procedures that load shed for identified critical natural gas and/or water facilities should only be executed as a last resort to maintain system reliability.

ii. Emergency Operations Training

ERCOT. Texas PUCT rules require that a market entity shall conduct or participate in one or more drills annually to test its emergency procedures if its emergency procedures have not been implemented in response to an actual event within the last 12 months. ERCOT does conduct winter storm and other drills (e.g., hurricane drills) biennially, as well as annual winter preparedness workshops. ERCOT also has multiple procedures for cold weather emergencies. ERCOT held a 2020 black start training session, but all other training sessions in 2020 were cancelled due to the pandemic. Black start training includes training associated with response to emergency recovery from frequency excursions.

ERCOT's system operator certification exam covers emergency operations topics, and system operators have available emergency procedures including several to provide advance notice to ERCOT system entities of approaching extreme cold weather. ERCOT's procedures allow operators the flexibility to send notifications multiple days in advance and include scripts that direct GOs/GOPs to take various actions to prepare for imminent cold weather, including reviewing and implementing winterization procedures, updating operating plans, and reviewing outages. ERCOT's procedures also address potential fuel issues, for example, requiring system operators to evaluate the weather forecasts for extreme conditions that could potentially lead to fuel supply problem, and directing shift supervisors to consider fuel switching.

TOPs and DPs normally perform load shed drills, and some entities conduct in-house load reduction drills with their system operations staff annually. Due to the pandemic, ERCOT did not conduct its winter 2020 load shed drills. The load shed drills fall into four broad categories: load shedding, system restoration, emergency operating procedures, and severe weather drills.

MISO and SPP. MISO performs load shed instruction drills with each of its LBAs monthly, coupled with testing of their emergency communications systems. Most TOPs and DPs in the MISO and SPP footprints typically perform load shed drills as part of their emergency operations training. All SPP TOPs and DPs voluntarily participate in SPP's annual load shed drills, which simulates an actual load shed event.[97] SPP also performs quarterly testing via a dedicated web-based Reliability Communication Tool (RCOMM). As part of the test, an electronic notice is sent by the SPP RC to all TOPs, requesting a test amount of load be shed. TOPs acknowledge the message, enter the test load amount, and submit the response to SPP.

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[97] SPP has only had one TOP miss the drill, due to a system emergency.

D. Prior Cold Weather Events and Recommendations

Extreme cold weather has jeopardized the reliable operation of the BES four times in the past 10 years, including the Event. From February 1 to 5, 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages and emergency power grid conditions and caused 6,886 MW of firm customer load shed in ERCOT, El Paso Electric and Salt River Project.[98] The January 2014 Polar Vortex event affected Texas, the Central and Eastern U.S., and resulted in generation outages, natural gas availability issues and less than 300 MW of firm load shed. And in January 2018, an arctic high-pressure system and below-average temperatures in the South Central U.S. resulted in many generation outages, and no firm load shed, but required voluntary load management emergency measures.[99]

Appendix B, which compares the weather conditions of the Event with past cold weather events in addition to the four BES events above, makes clear that although the Event was unusually cold, severe cold and freezing precipitation are far from unprecedented for winter in the Event Area. For example, other prior cold weather events had lower average daily temperatures for some days during each event.[100] For two of the five events, Houston and Jackson experienced at least one day for each of the week-long periods where the average daily temperature was below 10 degrees, and Dallas and Jackson experienced at least one day for each of the week-long periods where the average daily temperature was below 5 degrees. In all five events, average daily temperatures were below freezing in Dallas, Houston, and Jackson, for at least three days out of the week-long periods. The 1983 event had seven separate recorded cold fronts, while the 1989 event is still the coldest recorded winter in the Houston and Galveston areas, with 14 days below freezing over two to three weeks, and lows below those seen during the Event. The 1983, 2011 and 2018 events all had significant freezing precipitation, like the Event.

After each of the four BES events in the last ten years, one or more of the Commission, NERC, and/or the Regional Entities issued reports with recommendations to prevent similar events from recurring. Below the Team highlights the recommendations most relevant to the Event.[101]

1. 2011: ERCOT and Southwest

A joint FERC-NERC-Texas Reliability Entity report on the 2011 ERCOT and Southwest weather event was published in August 2011 and made 26 electric recommendations, in areas including

[98] SPP experienced weather-related generation outages and decreased natural gas supply, and several entities within SPP declared EEAs 1 to 3, but none shed firm load.

[99] This event was a near-miss. Although MISO and SPP did not need to shed firm load, MISO system analysis showed that if it lost its worst single contingency generation outage of over 1,000 MW, it would need to rely on post-contingency manual firm load shed to maintain voltages within limits and shed additional firm load to restore reserves. 2018 Report at 9-10.

[100] *See* Figures 115-117 in Appendix B.

[101] Appendix B compares the weather conditions of select extreme cold weather events that have occurred in the U.S. over the past 40 years, to gain understanding of the characteristics of these weather systems and how they can vary, including their temperature variations, their durations, and other weather conditions including precipitation and wind.

planning and reserves, coordination with GOs/GOPs, communications, load shedding and generating units' winterization, plant design, maintenance of freeze protection, and training on winterization. Among the recommendations that could have helped prevent the Event if followed were the following:

- GOs/GOPs inspect and maintain heat tracing equipment and thermal insulation, erect adequate wind breaks and enclosures, based on an engineering assessment, develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training (including the capabilities and limitations of freeze protection and methods for checking insulation integrity and heat tracing reliability) (##15-19)
- Consider designing any new plants and modifications to existing plants (unless committed solely for summer peaking) to be able to perform at the lowest recorded ambient temperature for the nearest city (factoring in accelerated heat loss due to wind speed) (#12)
- Assess the temperature design parameters of existing generating units (#13)
- TOPs and BAs obtain from GOs/GOPs forecasts of real output capability in advance of a severe weather event, which forecasts should take into account both the temperature beyond which availability of the generating unit cannot be assumed, and the potential for natural gas curtailments (#9), and
- TOPs and DPs conduct critical load review for gas production and transmission facilities (#25).

2. 2014: Polar Vortex

In September 2014, NERC staff published a report analyzing the January 2014 Polar Vortex event. NERC staff noted that natural gas units in two of the Regional Entity areas experienced higher-than-expected outage rates during the event,[102] and noted, "[t]his observation validates the concerns that NERC raised in the *2013 Long-Term Reliability Assessment* on increased dependence on natural gas for electric power."[103] In the Northeast, as units switched from gas to oil, some oil suppliers began to run low, which led to generation owners limiting run hours for their units—affecting approximately 2,000 to 3,000 MW of generation.[104]

NERC staff made ten recommendations, and those most relevant to the Event included:

- Examine natural gas supply issues; electric industry, gas suppliers, markets and regulators work to identify issues with natural gas supply and transportation, implement actions to allow generators to be able to secure firm supply and transportation at a reasonable rate.

[102] Polar Vortex Review at 18.
[103] *Id.* at 8, NERC, 2013 Long-Term Reliability Assessment http://www.nerc.com/pa/RAPA/ra/Reliability_Assessments_DL/2013_LTRA_FINAL.pdf, at 35.
[104] PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, Nat'l Hydropower Ass'n (May 8, 2014), https://www.hydro.org/wp-content/uploads/2017/08/PJM-January-2014-report.pdf.

- Review and update generating unit winterization (including procedures and training) as a result of lessons learned from the event, generating units should follow the Reliability Guideline.
- Entity winter assessments should include base assumptions and stress cases for the loss of varying amounts of natural gas-fired generation.
- Continue to improve awareness by BAs and RCs of the fuel status of generating units, including improved awareness of pipeline system conditions.
- GOs/GOPs should work to protect against outages within the ambient temperature design of the generating unit and determine if modifications should be made.
- Prepare to take proactive actions to secure waivers (market, environmental, fuel, etc.) from the appropriate entities when needed during emergencies.

3. 2018: South Central U.S.

A joint FERC-NERC-Regional Entity inquiry report published in July 2019 made thirteen recommendations, including a recommendation for potential new or revised Reliability Standards to address the need for generating units to prepare for cold weather and the need for BAs and RCs to be aware of specific generating unit limitations, such as ambient temperatures or fuel supply. (#1) This recommendation led to the Reliability Standards revisions approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021). Other recommendations relevant to the Event included:

- PCs and TPs should jointly develop and study more-extreme condition scenarios to be prepared for seasonal extreme conditions, including removing generating units entirely to model outages known to occur during cold weather and modeling system loads that accurately test the system for the extreme conditions being studied. (#7)
- Neighboring RCs should perform seasonal transfer studies and sensitivity analyses that model same-direction simultaneous transfers to determine constrained facilities. Among the scenarios suggested was simultaneous generating unit outages in adjacent RC footprints and increasing simultaneous transfers to a level where constraints cannot be fully mitigated. (#8)

Figure 18 provides a comparison of the four BES events' generating unit outages and load shed.

Figure 18: Comparison of Events' Effects on Bulk Electric System Generation and Resulting Need for Load Shed

	Feb. 1-5, 2011	Polar Vortex Jan 6-8, 2014	2018 Event Jan 15-19, 2018	2021 Event Feb 8-20, 2021
Deviation from Average Daily Temperature	17 to 36 deg F[105] below average	20 to 30 deg F[106] below average	12 to 28 deg F[107] below average	40 to 50 deg F[108] below average
Unavailable Generation Due to Cold Weather, at Worst Point (MW)	14,702[109]	9,800[110]	15,600[111]	65,622[112]
Causes of Unavailable Generation	Freezing Issues, Mechanical/ Electrical Issues, Natural Gas Fuel Issues	Freezing Issues (cold weather), Natural Gas Fuel Issues	Freezing Issues, Mechanical/ Electrical Issues, Natural Gas Fuel Issues	Freezing Issues, Natural Gas Fuel Issues, Mechanical/ Electrical Issues
Energy Emergency(s) Declared/ Highest Level	Yes/ EEA 3	Yes/ EEA 3	Yes/ EEA 2	Yes/ EEA 3
Maximum Firm Load Shed (MW)	5,411.6	300[113]	0[114]	23,418 (ERCOT 20,000, SPP 2,718, MISO South 700)
Overall Duration of Firm Load Shedding	ERCOT: 7 hours, 24 minutes	3 hours	N/A	ERCOT: over 70 hours, SPP: over 4 hours MISO South: over 2 hours

105 NOAA weather data.
106 Polar Vortex Review at iii.
107 2018 Report at 31.
108 NOAA NWS_WPC_Overview_February_2021.pdf (texasre.org), pg. 24.
109 2011 Report at 79.
110 2014 Report at 2, in the southeastern U.S.
111 2018 Report at 34 and 47.
112 The non-coincident Event Area peak of unplanned generation outages and derates was 65,622 MW, which occurred at different points in time: in ERCOT on February 15 at 1:05 p.m., MISO South on February 16 at 5:01 p.m., and SPP on February 17 at 12:17 a.m. The coincident peak of incremental unavailable generation in the Event Area was 61,305 MW, as shown in Figure 66a.
113 Polar Vortex Review at iii.
114 EEA 2/voluntary load management occurred.

III. Chronology of Events

A. Forecasts and Preparations for the Winter Storm[115]

1. Early Weather Forecasts Aided ERCOT, MISO and SPP in Predicting Severe Cold Weather

By late January/early February, ERCOT, SPP and MISO anticipated that severe cold weather was likely to occur in February. Both ERCOT and MISO employ meteorologists who assessed NOAA's forecast models and longer-term weather forecasts, and all three had weather forecasts provided by vendors which indicated the likelihood for extreme cold weather over the next two weeks. Armed with this information, the three RCs/BAs were able to issue early forecasts and preparation notices to GOs, GOPs, TOPs, and others within their footprints that the weather was going to turn much colder.

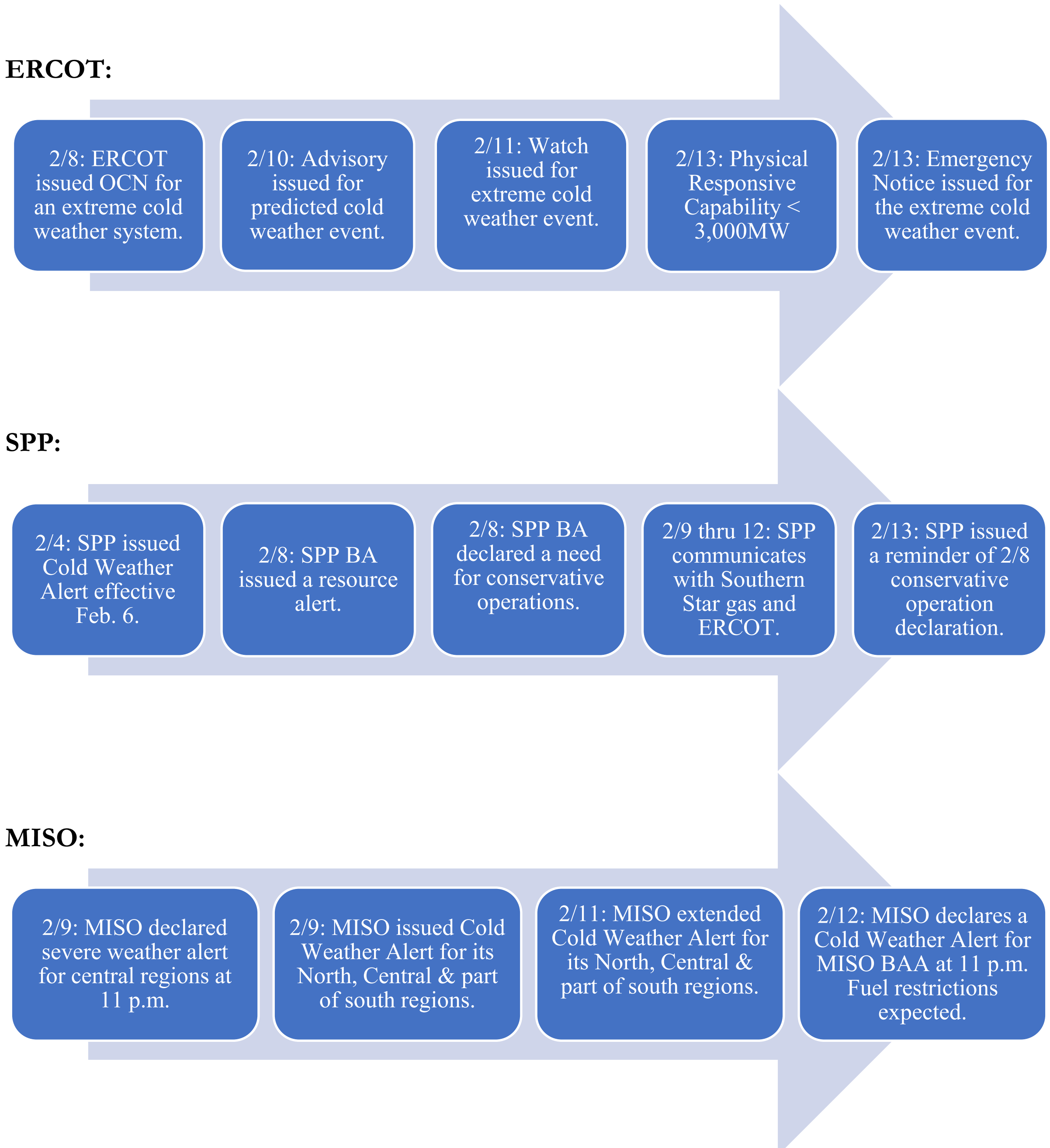
2. Notices Issued by Grid Entities in Advance of Severe Cold[116]

Aware of the impending cold weather, ERCOT, MISO and SPP began to warn other entities and to instruct them to prepare. The following Figure 19 and subsequent paragraphs summarize the information and notices ERCOT, MISO and SPP issued.

[115] Although many commentators refer to the weather event as "Winter Storm Uri," the Report does not, because NOAA did not. *But see* UT Report at 7.

[116] Here, alert is used generically to refer to any of the multiple communications that the BAs and RCs primarily used to communicate system conditions during the Event. *See* Appendix K for a description of the various levels of alerts and Energy Emergencies used by ERCOT, MISO and SPP. Appendix C contains an example RC alert issued during the Event. OCN, or Operating Condition Notice, is the lowest level of communication used by ERCOT in anticipation of an emergency condition.

Figure 19: Alerts Issued in Advance of the Coldest Weather, February 8-13, 2021



<u>**ERCOT**</u>. As early as January 28, ERCOT's resident meteorologist began communicating the mid-February potential for severely cold weather, with temperatures along the lines of the 2011 event. From that day onward, the meteorologist sent daily internal email communications, which included temperature and precipitation forecasts as well as subject matter commentary to ERCOT staff

(system operations, outage coordination, load forecasting, various executives, other targeted employees) and published information on the ERCOT website.[117]

On February 8, 2021, ERCOT issued two Operating Condition Notices (OCN) to QSEs and TOs. In the morning, ERCOT issued an OCN (via its hotline and posted on its website) for predicted freezing precipitation for the Panhandle and North areas of the ERCOT region beginning Wednesday evening, February 10 through Thursday, February 11. That evening, ERCOT issued a second OCN for an extreme cold weather system approaching Thursday, February 11 through Monday, February 15, with temperatures anticipated to remain at or below freezing. QSEs were instructed to update ERCOT as soon as practicable on changes to generating units' availability and capability; review fuel supplies, prepare to preserve fuel to best serve peak load; notify ERCOT of any known or anticipated fuel restrictions; review planned resource outages and consider delaying maintenance or returning from outage early; review and implement winterization procedures; and notify ERCOT of any changes or conditions that could affect system reliability. ERCOT instructed TOs to review planned and existing transmission outages for the possibility of canceling outages or restoring equipment; review and implement winterization procedures; and notify ERCOT of any changes or conditions that could affect system reliability.

On February 11, 2021, ERCOT issued a Watch, in which, in addition to steps already taken under the OCN, ERCOT instructed QSEs to implement winterization and emergency operating procedures including pre-warming of generating units.[118] Eventually on February 13, 2021, ERCOT issued an Emergency Notice for extreme cold weather on its public website.

MISO. Beginning on February 9, MISO began to communicate with its members about the upcoming severe weather, by issuing a Cold Weather Alert effective for February 13 to 15, which was extended through February 16 on February 11.[119] On February 10 and 11, it issued Informational Advisories reminding generating units to update MISO on fuel availability and implement their winterization or maintenance. On February 13, MISO committed all long-lead generating units and issued a Capacity Advisory for MISO South. On February 14, MISO issued a Maximum Generation Emergency Alert for MISO South, which required generating units to suspend maintenance activities, effective February 15.

SPP. SPP issued a Cold Weather Alert on February 4, 2021, effective February 6. On Monday, February 8, 2021, SPP escalated to a Resource Alert, which triggers generating units to complete any

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[117] Closer to the Event, on February 4, 2021, ERCOT's meteorologist, in his market information forecast, warned market participants that the forecast suggested a likelihood that the cold air would "push all the way through Texas by the second half of next week," and noted that "next Friday through the weekend (i.e. February 12 to 14) has the potential to be the coldest period of the winter." ERCOT Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation, at 9, http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf; ERCOT Market Information forecast for February 4.

[118] This was a recommendation from the 2011 Report. 2011 Report at 60-61.

[119] *The February Arctic Event February 14-18, 2021*, Miso Energy, 15 https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf.

preparations, ensure that they can meet their commitments and report any fuel shortages.[120] On Tuesday, February 9, 2021, SPP declared Conservative Operations,[121] and on Thursday, February 11, it began committing long-lead generation through its reliability assessment process instead of its normal day-ahead commitment process.

3. Winter Preparations by Generator Owners and Operators and Responses to Alerts[122]

The Team reviewed how generating units prepared for cold weather in the ERCOT, SPP and MISO footprints. Depending on the type of fuel, generating units took specific actions to ensure they would remain in operation during the Event.

Wind units in ERCOT and SPP prepared by performing annual service and winterization checks, canceling planned maintenance, ordering additional nitrogen[123] for maintaining the hydraulic braking system, activating the emergency response team to assist in coordination, providing continuous personnel coverage at the facilities, checking operational conditions of critical heating systems, notifying contractors of the need to be available during the Event, ensuring road access, and modifying on-site inspection rounds to more closely monitor the turbines for ice buildup. In SPP, one large GO activated its Emergency Response Team before the storm to provide support and coordination for all units, which triggered daily meetings and activities across a broad geographic area. Emergency Response Team members mobilized throughout Texas and Oklahoma to be staged at high-impact locations.

Solar units in ERCOT and MISO South prepared inverters by checking the functionality of heaters, ensuring adequate temperature settings and functioning alarms, and activating emergency response teams.

Natural gas-fired units across all regions prepared for the Event by, among other things, deploying emergency plans and adding personnel, including operators to more frequently check freeze protection (and quickly address any issues); checking natural gas inventories and placing natural gas commodity orders in advance; testing heating supplies and protective equipment; installing temporary heat tracing, tarps, and insulation to prevent equipment from freezing; verifying that pumps were running; checking temperature gauges; replenishing cold weather gear; placing snow

[120] *A Comprehensive Review of Southwest Power Pool's Response To The February 2021 Winter Storm Analysis and Recommendations,* Southwest Power Pool, 27 (Aug. 2011), https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf.

[121] Conservative Operations is declared when SPP determines there is a need to operate its system conservatively based on weather, environmental, operational, terrorist, cyber or other events.

[122] Although many of these preparations happened shortly before the Event, some started before the winter.

[123] Nitrogen is used as part of a braking system to prevent the wind turbine from operating at speeds that would damage the blades. Over time, the nitrogen level in the cylinder can drop and needs to be refilled. *Improve Wind Turbine Safety with a Piston Accumulator Retrofit,* Power (Sept. 21, 2020), https://www.powermag.com/improve-wind-turbine-safety-with-a-piston-accumulator-retrofit/.

removal equipment and portable generators connected to batteries on site; opening water valves and low-point drains; checking that freeze protection panels are in service and all circuits are energized; and, for dual-fuel[124] units, filling condensate systems to prepare for water injection usage if required to change to fuel oil. In SPP, some GOPs reported testing units prior to the Event for black start capability and full speed no load tests. A GO/GOP in SPP reported ensuring snow and ice removal equipment and supplies were available and portable generators and heaters deployed around the plant as necessary. In MISO South, some GOs/GOPs reviewed and updated winterization checklists for each site annually to add newly-installed equipment (equipment is added to the list based on previous freezing experience) and remove retired equipment, and placed certain equipment in service when the ambient temperature reached a pre-selected point. For example, some GOs/GOPs had their lube oil cooling water pumps placed in continuous service when the temperature is expected to be 25 degrees or less for at least eight hours. GOs/GOPs also established firm gas transportation arrangements and exclusive provider agreements with gas suppliers and review cold weather event procedures with operations and maintenance groups at the beginning of the winter season. Plant personnel reviewed open work orders that could affect plant operation and completed maintenance activities prior to the onset of the Event. Plant personnel drained the inlet air chiller coils and filled the demineralized water tanks to maximum capacity in preparation for the Event. Beginning on February 15, plant personnel from one GO were onsite 24 hours a day until conditions in MISO South improved. Extra operations staff sequestered onsite overnight to ensure adequate operations coverage during inclement weather and deteriorating road conditions.

Oil-fired generating units also performed maintenance, checked heat tracing, and checked temperature gauges. In addition, they prepared by insulating critical control valves, test-starting black start diesel units, procuring extra fuel oil and filling fuel and storage tanks onsite, staging additional diesel heaters and barriers/wind breaks, and verifying pumps, heaters and igniters were operational. Dual-fuel generators that would normally burn natural gas also burned a mixture of gas and oil to conserve gas.

Coal-fired generating units across all regions, like other types of generators, placed and inspected insulation, added heaters around critical components (e.g., coal mills), and brought in additional operations and maintenance personnel to prepare for and respond to the Event. GOs/GOPs with coal-fired generating units in ERCOT also prepared by coating coal cars to prevent coal from sticking due to freezing and maintaining water flow through piping in offline systems. To obtain maximum performance from coal units, facilities located in Texas worked with the Texas Commission on Environmental Quality to relax emissions constraints on February 15. In SPP, an entity started auxiliary boilers early for additional building heat. In MISO South, preparations included inspecting heat tracing and insulation, installing wind breaks, and checking inventory of ice melt.

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[124] *See* Fuel Switching: A Missed Opportunity, for more information on dual-fuel units (p. 225).

4. Near-Term Grid Preparations Taken in Advance of Severe Cold Weather

a. Short-Term Load Forecasts

ERCOT. ERCOT produces a seven-day ahead hourly load forecast for each of the weather forecast zones in its footprint, using data from two weather vendors. Beginning the week of February 7, ERCOT deviated from its typical practice of using a single forecast model for an entire 24-hour day and used multiple forecast models to better reflect load variations at different points during the day.

SPP. SPP uses weather forecast data to generate seven-day hourly load forecasts used for operational planning studies and assessments. This information is also used to determine any risks and uncertainty associated with generation or transmission availability. SPP's uncertainty response team, who account for risks including weather, load, wind, and resources, advised the real-time system operators in advance of the severe cold weather that the load forecasts for the week of February 14 may be understated.

MISO. MISO generates a temperature forecast tracking dashboard daily. The dashboard consists of an hourly look-ahead temperature forecast for the remainder of the current day and the next six days, for each of MISO's five weather zones.

The following Figures 20 - 22 compare short-term load forecasts developed by ERCOT, MISO (for its MISO South region) and SPP to the actual peak system loads for February 15, 2021, for each of their respective footprints.

Figure 20: ERCOT's Near-term Peak Load Forecasts and Percent Error for ERCOT: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of February 15, 2021

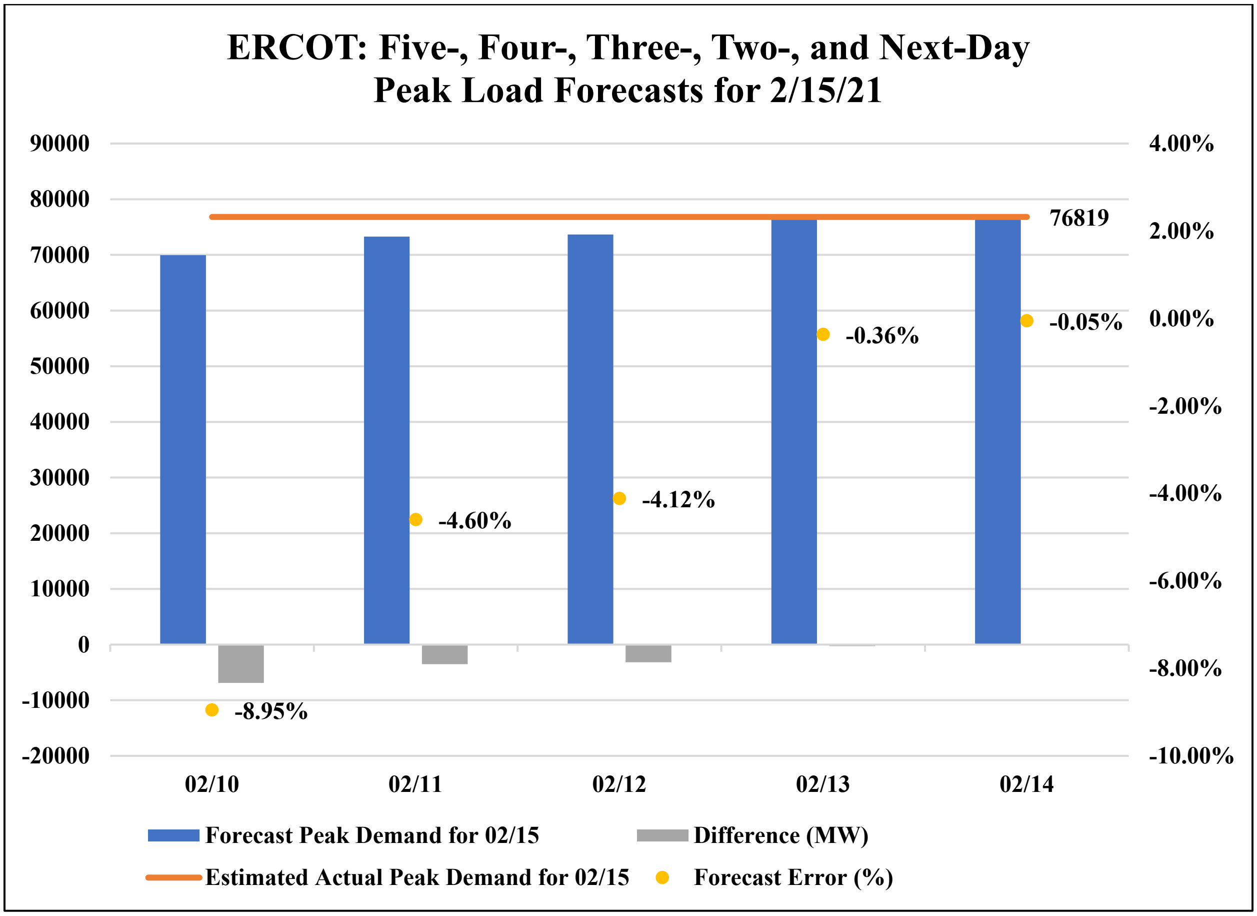


Figure 21: MISO's Near-term Peak Load Forecasts and Percent Error for MISO South: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of February 15, 2021

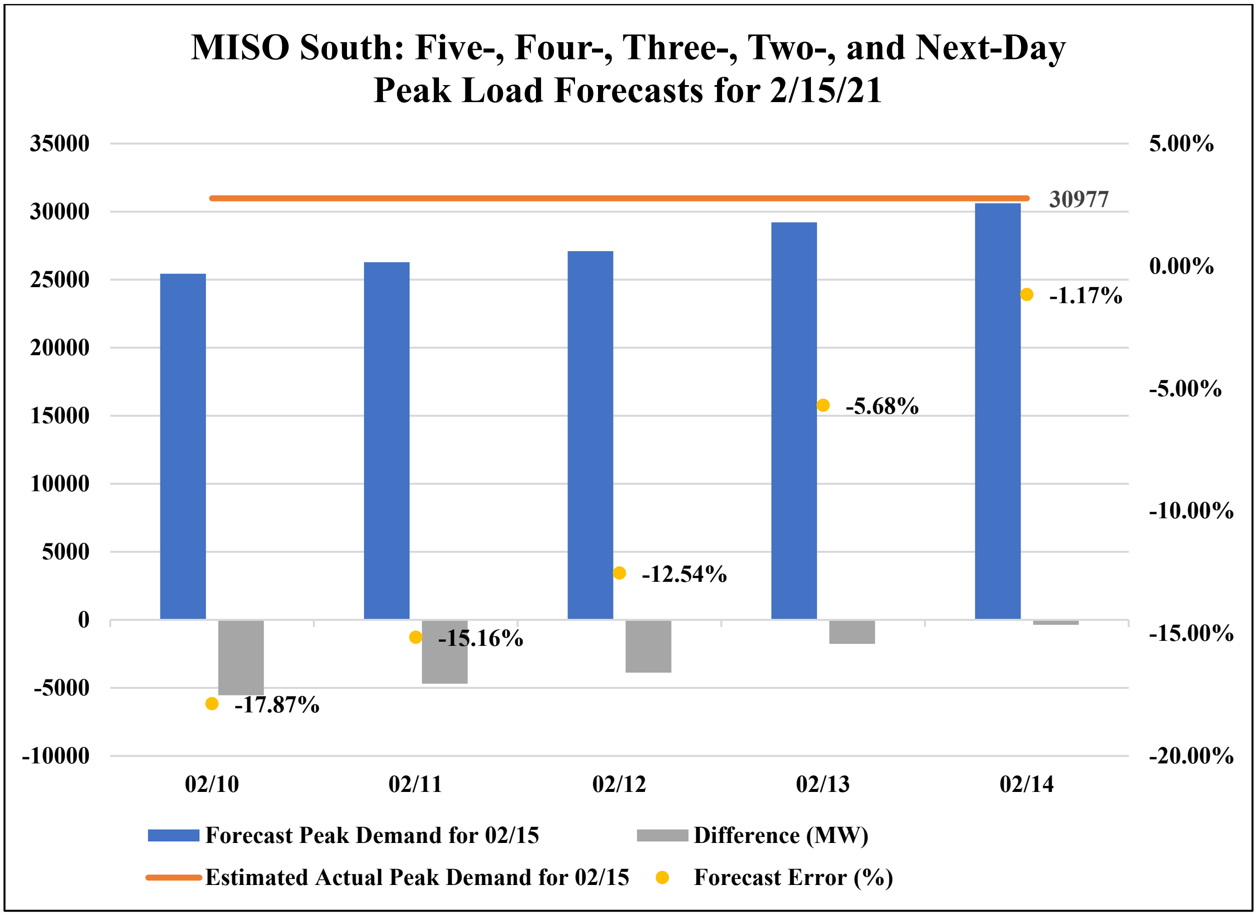
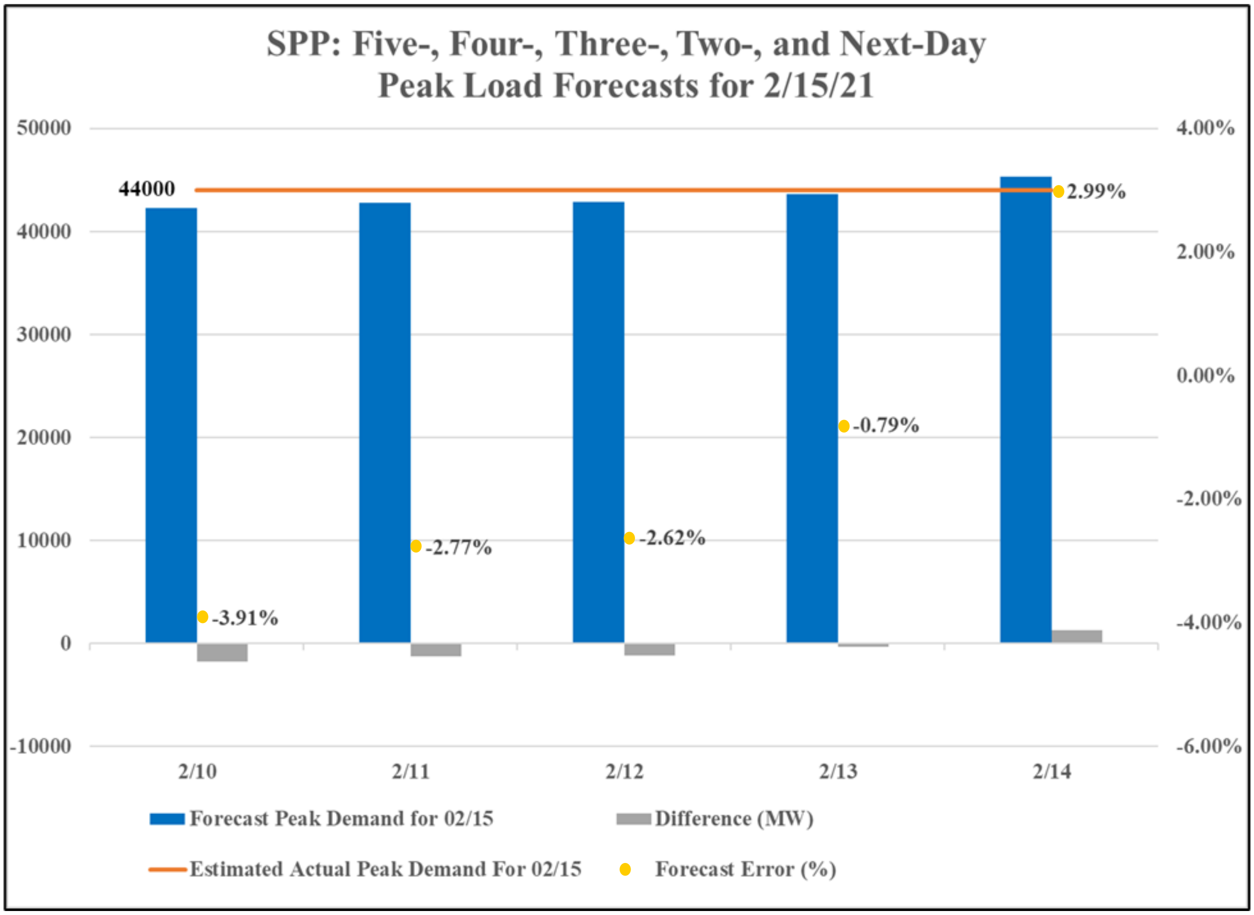


Figure 22: SPP's Near-term Peak Load Forecasts and Percent Error for SPP: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of February 15, 2021



MISO's five-day, four-day, and three-day-ahead peak load forecast errors shown in Figure 21, above, in forecasting the "estimated" MISO South peak load for February 15, 2021 were larger (approximately 17.9 percent/5,500 MW, 15.2 percent/4,700 MW, and 12.5 percent/3,900 MW lower than actual peak load, respectively) than forecast error rates for the same period for the other BAs involved in the event. ERCOT's and SPP's load forecasts comparable to this timeframe (shown above in Figure 20 and 22, respectively) were more accurate (with error rates ranging from nine to four percent lower than actual peak load for five-days-out, 4.6 to 2.8 percent lower than actual for four-days-out, and 4.1 to 2.6 percent lower than actual for three-days-out). As shown in Figures 20 to 22 above, all of the BAs' load forecast errors trended towards zero percent as February 15 approached and ranged between 2.99 percent above to 1.17 percent lower than the actual peak demand for the day-ahead load forecast.

b. Total Unavailable Generation before February 8

Prior to the Event,[125] ERCOT had 3,079 MW of planned generation outages, and 10,633 MW of unplanned generation outages and derates (for total unavailable generation of 13,712 MW); MISO South had 1,793 MW of planned generation outages, and 1,406 MW of unplanned generation outages and derates (for a total of about 3,199 MW of unavailable generation); while SPP had 6,238 MW of planned generation outages, and 11,264 MW of forced generation outages and derates (for a total of 17,502 MW of unavailable generation). These outages and derates are shown in Figures 23 and 24, below.

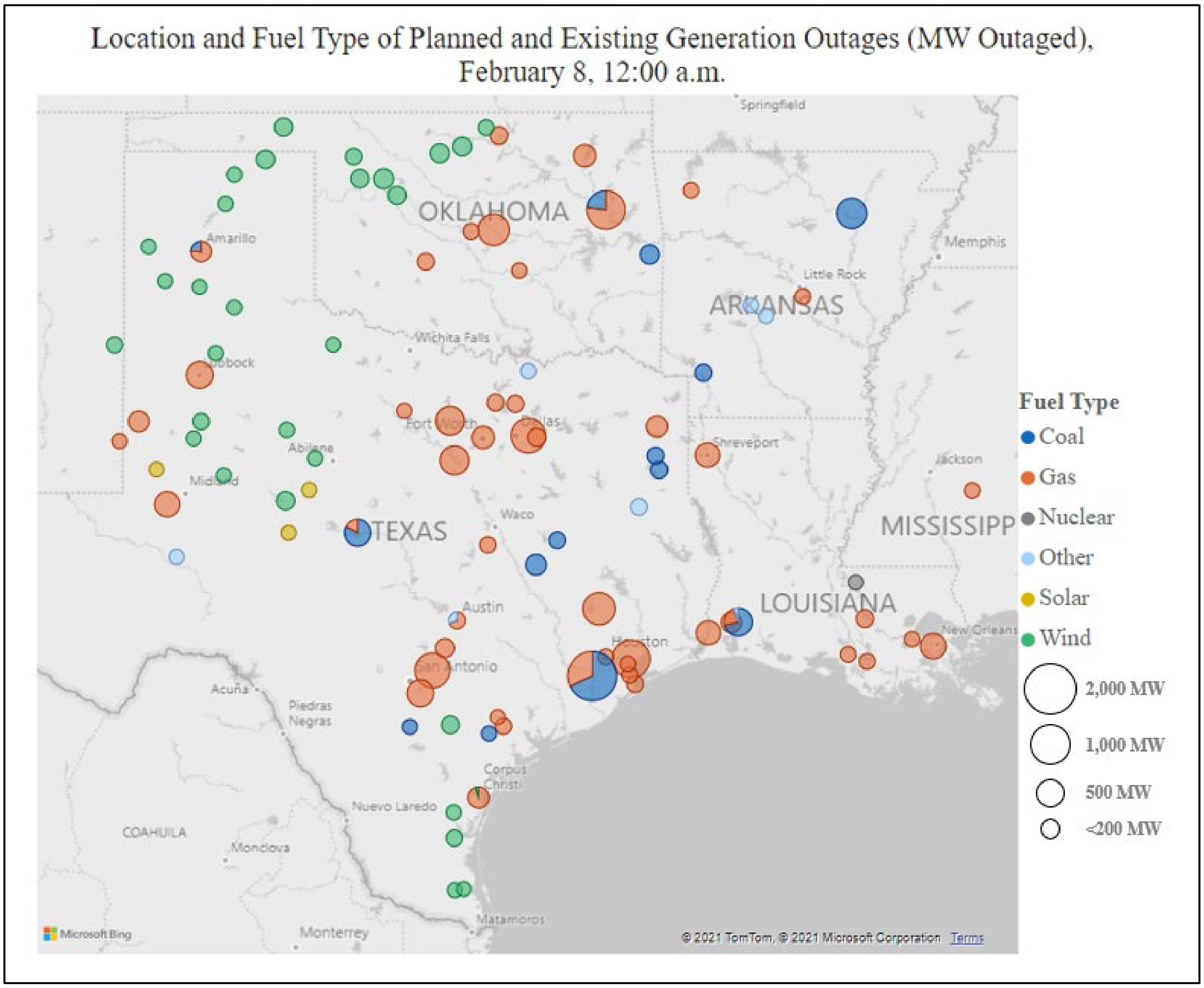
Figure 23: Total Unavailable Generation (MW) Prior to Event and Percent of Installed Capacity[126]

Total Unavailable Generation (MW) Prior to Event[1] and Percent of Installed Capacity			
	ERCOT	**MISO South**	**SPP**
Planned Generation Outages	3,079 (2.5%)	1,793 (4.3%)	6,238 (6.6%)
Unplanned Generation Outages	10,633 (8.6%)	1,406 (3.3%)	11,264 (12.0%)
Total Unavailable Generation	13,712 (11.1%)	3,199 (7.6%)	17,502 (18.6%)
Total Installed Capacity	123,057	41,865	94,232

[125] As of 12:00 a.m. on February 8, 2021.

[126] Just prior to the Event, the unplanned (or forced) generation outages and derate percentages of the total installed capacity for ERCOT, MISO South and SPP were 8.6%, 3.3% and 12.0%, respectively, as shown in Figure 23, above. These percentages were lower than the generation annual Weighted Equivalent Forced Outage Rates (WEFOR) for 2020 for TRE (covers Texas, including ERCOT), SERC (predominantly covers southern U.S., including MISO South), and for MRO (covers large portion of SPP) were 9.4%, 7.5%, and 13.9%, respectively. According to NERC, "WEFOR measures the probability that a group of units will not meet their generating requirements because of forced outages or forced derates. The weighting gives larger units more impact to the metric than smaller units." General Availability Review (Weighted EFOR) Dashboard (nerc.com).

Figure 24: Location and Fuel Type of Planned and Existing Forced Generation Outages in ERCOT (MW Outaged), February 8, 12:00 a.m.[127]



c. Generation and Transmission Returned to Service/Outages Cancelled

In ERCOT, the Outage Coordination group worked closely with TOs to return transmission outages to service. Beginning February 8, ERCOT outage coordination staff began evaluating outaged facilities that could be placed back in service. ERCOT staff evaluated priority transmission outages with long restoration times and notified transmission entities to cancel or withdraw priority outages that could be restored to service by February 12. Ultimately, ERCOT canceled or rejected 75 transmission outages from February 8 to February 22. ERCOT staff also reviewed planned

[127] Figure 24 is a baseline, while Figures 34, 68, and 74 are a time series showing how the unplanned outages grew during the Event. The purpose of the time series is to give a sense of how widespread the outages were geographically, how they varied in fuel type, and how they worsened over time.

generation outages to identify those that could potentially return to service early, resulting in the cancellation of 75 planned generation outages on 53 generating units.

As early as February 8, MISO staff began reaching out to generating units in the Event Area, asking that they defer maintenance and refueling outages and return generating units to service. MISO succeeded in postponing some significant outages, for example, the maintenance outage, planned to start on February 13,[128] of a 1,000 MW-plus nuclear unit, and the suspension/retirement of a 411 MW natural gas-fired generating unit, and in total canceled or revoked 168 generating unit outages planned between February 8 and February 22.

SPP's outage coordination team contacted all TOPs and GOPs with outages scheduled during the period of February 9 through February 20 and requested that any outage that was not designated as "emergency" or "forced-priority" be rescheduled. SPP then denied or rescheduled all non-emergency or non-forced outages during that period, canceling or denying 19 generating unit outages planned to start between February 9 and February 22. On February 12 and February 14, SPP held conferences with its Operating Reliability Working Group to clearly communicate expected grid conditions. TOs and TOPs were asked about changes or adjustments that were made between February 7 and 13 to any transmission outage plans or ongoing transmission outages for the week beginning February 14, such as postponing a planned outage that had not begun to a later time during the approved scheduled window, rescheduling a planned outage that had not begun to an entirely different scheduled window, recalling an outage that had begun to be completed at another time, or cancelling an outage, planned or ongoing, altogether. Of the TOs/TOPs that responded, 64.6 percent indicated that changes were made to current and planned transmission outages prior to the Event. The remaining 35.4 percent either had no outages planned or made no changes to ongoing transmission outages.[129]

d. Generation Committed Early for Reliability

On Thursday, February 11, MISO committed long-lead generation of approximately 3 GW in the North/Central region and approximately 5.5 GW in the South region in preparation for the winter storm. Long-lead generators are generators with a time to start time greater than 24 hours, during which they may need to take specific actions including fuel procurement, staffing, or startup procedures. On February 11, SPP also began committing generation, regardless of start-up lead time, through its reliability assessment process instead of its normal day-ahead commitment process, which meant even generating units with a short lead time for start-up were committed, along with long-lead generators. SPP continued this approach through the week of February 14 using its multiday reliability commitment process, [130] to improve the chance for fuel procurement by the generators.

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[128] According to MISO, it paid over $5.1 million dollars to compensate the GO for this delay.
[129] Depending on the nature of the work, some ongoing transmission outages are impossible to restore until completion of work; for example, a substation or transmission line construction project that has begun and involved removal of equipment.
[130] *See* section III.B.4.(b) for description of SPP's multiday reliability commitment process.

Fuel procurement was of special concern during the Event because it was a holiday weekend (Presidents' Day). SPP committed natural gas-fired generating units earlier than normal to give them the ability to purchase supplemental gas supplies ahead of a long holiday weekend. Natural gas supply trading and pipeline transportation nominations occur every day for delivery the next flow day; however, standard next day gas trading occurs only on business days. Next-day trading for flow days Saturday, Sunday and Monday occurs on Fridays, with exceptions for holidays. Some less-liquid markets offer products that break up the weekend package or trade during the weekend itself. Due to the Presidents' Day holiday, natural gas units committed by the early morning of Friday, February 12 for Saturday February 13 to Tuesday, February 16 had better options for procuring natural gas than units that received commitments on a day-by-day basis throughout the weekend. Natural gas-fired units committed during the holiday weekend or for only part of the holiday weekend had limited options for procuring gas supply and transportation.

5. Near-Term Preparations by Natural Gas Infrastructure[131]

Production. Production facilities' preparation for the Event began up to a week prior to the Event and focused on three main areas: freeze protection, fluid management and staffing/communications.[132] Freeze protection measures included: ensuring supplies of methanol, other hydrate suppressants,[133] and antifreeze; burying and upsizing sensing lines; and adding heat tracing, tarps, barriers, and insulation. Fluid management measures included drawing down oil and water tanks, securing generators for backup power at critical facilities (saltwater disposal wells, water transfer systems), securing additional frac tanks, and preparing for other water/oil management procedures (i.e., agreements with gatherers and processors to flow oil, water, and gas through various pipelines in order to maintain production).[134] Staffing and communications measures included prioritizing field operations in the affected production basins, and increasing internal and external (with midstream gathering, processing, and gas sales counterparties) communications.

A limited number of gas production facilities decided to proactively shut in their wells before the Event began, which eliminated the need for other preparation measures. Gas production facilities primarily decided to proactively shut in their wells for one of two reasons: (1) safety, environmental and asset protection, aimed at quick recovery of operations post-Event; or (2) focusing resources on wells viewed as more productive (whether based on higher flow/volume or the composition/ratios of liquids and gas) and minimizing resource allocation to less-productive wells.

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131 Unless otherwise stated, the source of data for this section is the sample of producers, processors and pipelines that responded to the Team's data requests. *See* Appendix I.

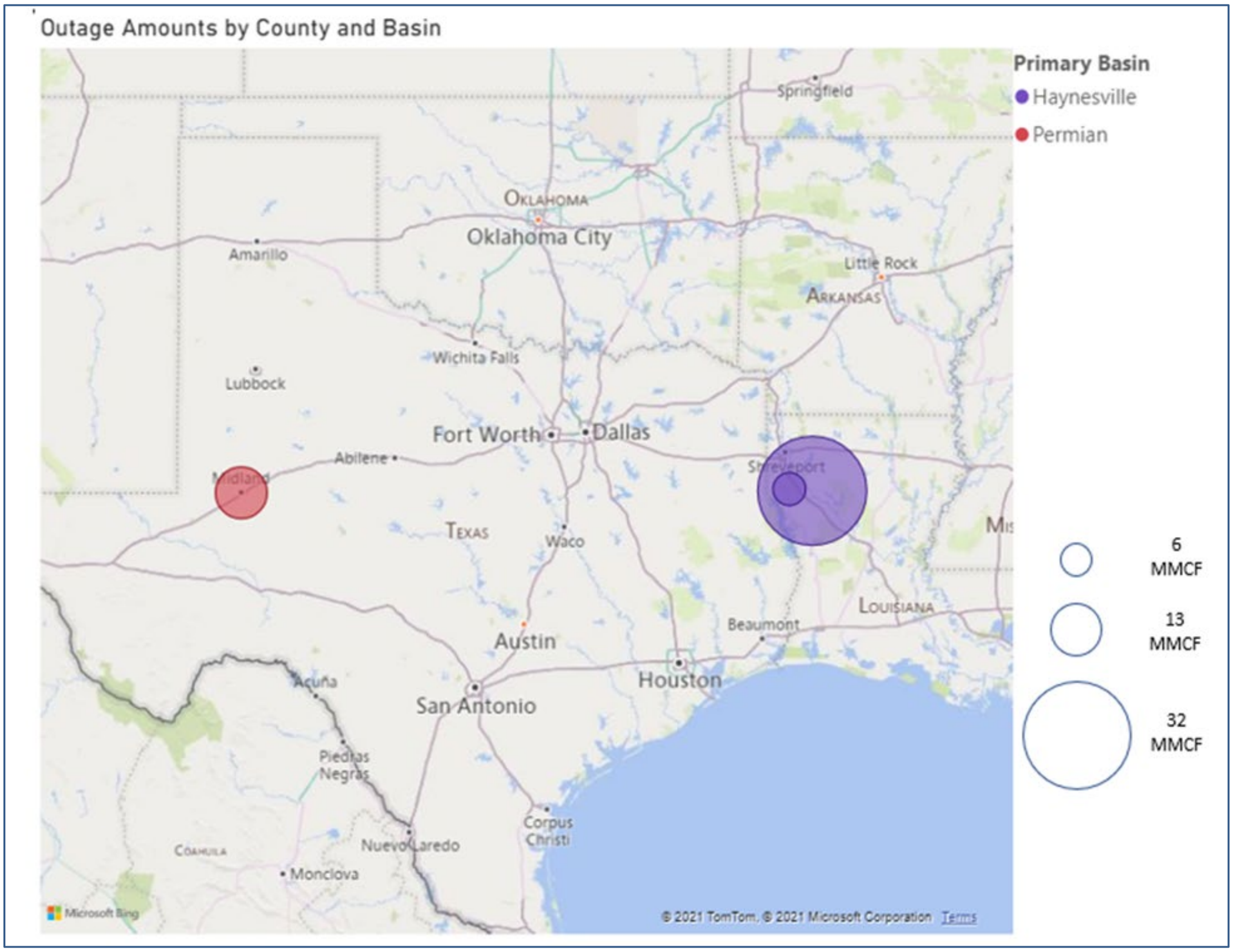
132 Producers also stockpiled necessary equipment such as heating devices, and batteries for instrumentation and electronics/control/communications equipment power.

133 T.F. Welker, Freeze Protection for Natural Gas Pipeline Systems and Measurement Instrumentation, https://welker.com/freeze-protection-for-natural-gas-pipeline-systems-and-measurement-instrumentation/.

134 One entity added produced water systems in 2020. Wells connected to its water gathering systems were not reliant on water haulers, which helped ensure that production remained online, and increased the percentage of its production from those wells.

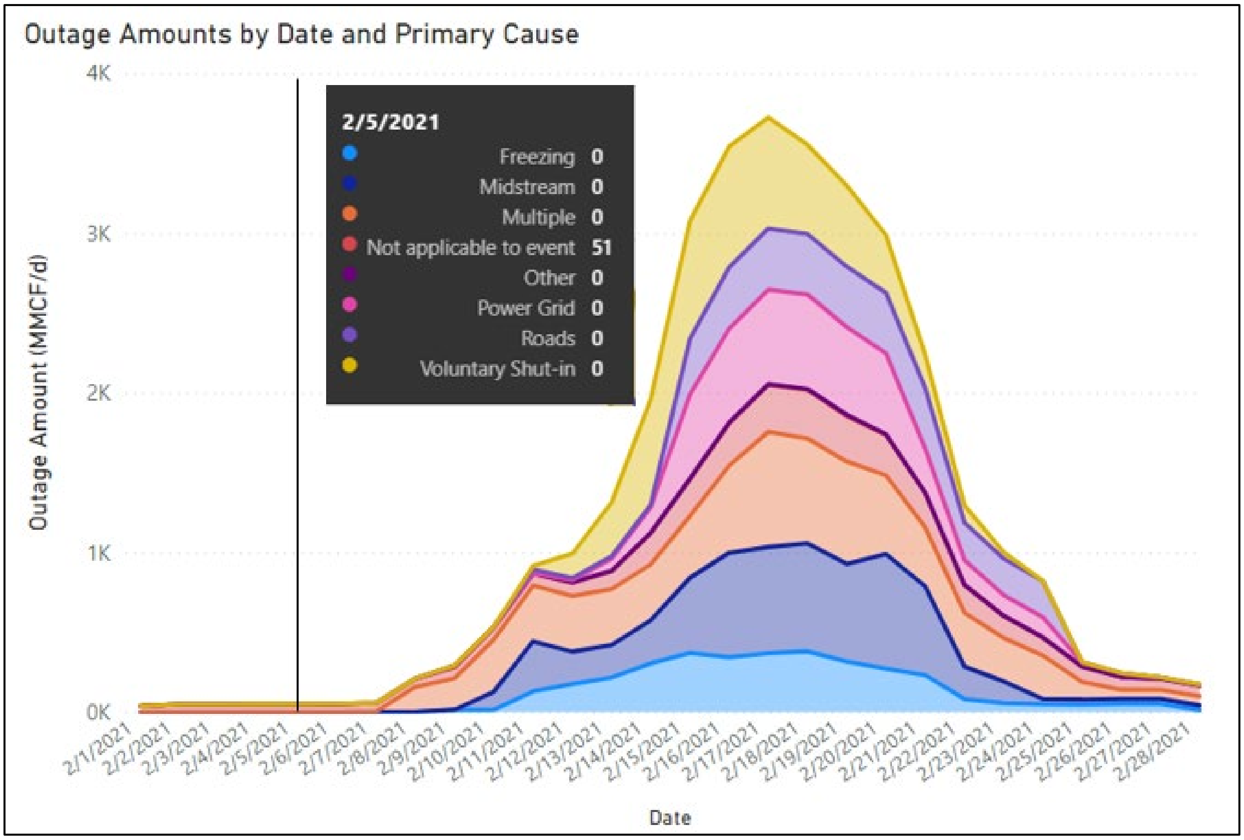
Figures 25a and 25b, below depict natural gas production outages prior to the Event (Figure 25a), based on sample of production data gathered, and the primary causes (Figure 25b).[135]

Figure 25a: Natural Gas Production Volumetric Outages by Primary Basin, Before Event (February 5)[136]



[135] Figure 25a is a baseline, while Figures 38a, 39a, 48a, 49a and 50a are a time series showing how the unplanned natural gas production outages grew during the Event. The purpose of the time series is to give a sense of how widespread the outages were, and how they worsened over time.
[136] All outage events smaller than 1 million cubic feet (MMCF) are excluded from figure.

Figure 25b: Natural Gas Production Volumetric Outages by Cause, Before Event (February 5)



Processing. Natural gas processing facilities' preparations focused on electric power supply, equipment and maintenance, and personnel. Measures taken to protect electric power supply included obtaining and maintaining backup generation for gas control centers and some critical facilities.[137] Equipment and maintenance measures included performing maintenance before the cold weather season, ensuring an adequate supply of methanol (which addresses hydrates in pipes) and critical spare parts. Personnel measures included confirming personnel availability to respond to equipment failures or other plant issues, holding daily operational update meetings, and coordinating with producers, customers and purchasers of the residue gas produced by the plant.

Pipelines. Preparation for the Event started in early February. Pipelines implemented severe/winter weather procedures to ensure the safety and integrity of their systems and many pipelines issued operational flow orders (OFOs) notifying shippers about the winter weather and the need to remain in balance.[138] Pipelines prepared for power outages and maintained appropriate levels of line pack. Before the Event, some ran prospective storage activity reports daily, or more

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[137] Backup generators were only capable of providing small amounts of power and were not capable of powering an entire processing facility. Sixteen out of 50 processing plants that responded had some form of alternative power source.

[138] In general terms, shipper imbalances occur when there is mismatch between a shipper's deliveries of natural gas into the pipeline and the natural gas the shipper takes off the pipeline.

frequently as needed, to forecast storage inventory and withdrawal requirements. Other pipeline preparations before the Event included: providing additional staffing at critical field operations, including key delivery stations, compressor stations and storage fields; testing emergency generators before the event to avoid any power interruptions; staging spare batteries at meter stations; verifying that heated stands were properly functioning to prevent meter stations from freezing; testing operating plans for power outages and SCADA[139] system failure; performing proactive pressure adjustments and plate changes to stations expected to be heavily impacted; increasing communication among and within the various pipeline entities; and increasing monitoring of receipt and delivery flows.

6. Coordination in Advance of the Severe Cold Weather

a. Coordination Between Reliability Coordinators

SPP and MISO RCs began coordination on February 8. SPP and MISO exchanged information regarding transmission and generation capacity challenges. Communication between SPP and MISO RC system operator desks remained constant in real time and involved discussions of energy emergencies and coordination of transmission congestion, with real-time feedback from and to management as necessary (e.g., timing of Transmission Loading Relief (TLR) issuances, assistance to ERCOT).

Coordination between SPP and ERCOT RCs began on February 12, and covered issues related to switchable generating units, the fuel supply for those units, DC tie curtailments and restoration of interchange schedules. Switchable generation resources may or may not be physically located inside ERCOT, but are interconnected to, and registered to participate in, the ERCOT market as well as SPP's market. SPP and ERCOT coordinated on dispatching the switchable units as appropriate, given the existing system emergencies. ERCOT requested emergency assistance through the DC ties from SPP; however, because SPP was also experiencing EEAs at times, it could not provide emergency assistance. SPP did allow the switchable resources to be released into ERCOT even though SPP was in EEA 2, because SPP had a relatively lower risk of load shed than ERCOT, which was already in EEA 3 and ordering firm load shed.

The RCs used Reliability Coordinator Information System (RCIS) messages, including declarations of their respective EEAs and Transmission Emergencies, Interchange Distribution Calculator (IDC) TLR curtailments,[140] and telephone communications during the Event and discussed TLRs with other RC system operators over the phone. MISO and SPP held daily morning RC-to RC-calls to

[139] A Supervisory Control and Data Acquisition (SCADA) system operates via coded signals sent over communication channels to remote stations to monitor and provide control of remote equipment.
[140] A Reliability Coordinator is the only entity authorized to initiate the TLR procedure and shall do so at its own request or upon the request of a Transmission Operator. A Reliability Coordinator may use the TLR procedure to mitigate potential or existing System Operating Limit (SOL) violations or to prevent Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC. *See* https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Levels.aspx for more details regarding the TLR levels and associated Reliability Coordinator actions.

discuss operational awareness updates. Overall, the three RCs maintained good communication with each other as necessary to preserve reliability.

b. Natural Gas – Electric Coordination

BAs gathering natural gas supply information: MISO and ERCOT send out a fuel survey to GOPs each winter. SPP does not perform an annual survey but a biannual one, which was last performed in 2019, and it did not perform one before the 2020/2021 winter.[141] ERCOT, MISO and SPP all have some sort of system to monitor fuel supplies. MISO has a procedure for using natural gas pipeline critical notices and other information for situational awareness. Among other tools it prepares a generator fuel impact report, pipeline-generator overview map, and a daily gas outage report. MISO also requires GOPs to modify their day-ahead or real-time offers if affected by natural gas pipeline critical notices. ERCOT requires QSEs to submit and maintain a Current Operating Plan (COP).[142] If generating units are impacted by fuel supplies, in addition to updating their COPs, ERCOT also requires QSEs to submit outages or de-rates in the ERCOT Outage Scheduler.

While in conservative operations conditions on February 11, SPP received critical notices such as OFOs for the upcoming week beginning February 15. MISO had only three ongoing EBB notices on the Enable, Mississippi River Transmission, and Texas Eastern Transmission pipelines in January. Beginning the first week of February, the number of natural gas pipeline critical notices posted began to increase because of shipper imbalances (caused by natural gas production declines and the cold weather). Additionally, on February 4, generation outages reported to MISO with the cause "fuel transportation/supply issues" increased from 7 MW to 1,502 MW.

ERCOT received an email from Atmos-Pipeline Texas on February 10, stating that beginning February 12, there would be Level 4 restrictions on gas supply, meaning that generating units supplied by Atmos would be cut off completely. ERCOT also received multiple notifications and instructions regarding potential fuel supply issues from its QSEs beginning on February 8.

SPP and Southern Star had been communicating directly with each other since February 9. Other pipelines and BAs/RCs in the Event Area did not communicate directly on a regular basis before or during the Event. BAs and RCs generally relied on FERC-mandated interstate pipeline EBB information but had less visibility when relying on intrastate pipelines.

Natural gas infrastructure designation as critical/demand response: Generally, natural gas infrastructure facilities engaged in little coordination with their electric power providers prior to the Event. For instance, there was little coordination as to critical load designation and demand response programs. Natural gas infrastructure facilities vary significantly in their reliance on grid

[141] SPP will now perform annual fuel surveys.

[142] Current Operating Plan (COP) - A plan by a Qualified Scheduling Entity (QSE) reflecting anticipated operating conditions for each of the Resources that it represents for each hour in the next seven Operating Days, including Resource operational data, Resource Status, and Ancillary Service Schedule. *See* ERCOT Nodal Protocols, Section 2: Definitions and Acronyms (September 2021) - http://www.ercot.com/content/wcm/current_guides/53528/02-090121_Nodal.docx

power, use of onsite generation or alternative power sources, and the impact a loss of power would have on operations.

There was minimal gas-electric coordination between owners/operators of natural gas production facilities and their electric suppliers with respect to critical load designation. Responding entities' production facilities vary, both in scope of operating facilities and power needs. Some producers only own and operate wellheads and associated equipment. Some producers own and operate gathering systems/facilities, and/or saltwater disposal wells, which require power to maintain operations. Power requirements for natural gas production facilities may include the need for power to run operating equipment (e.g., artificial lifts, pumps, compressors, etc.) and "control power" to run instrumentation, control, communication and/or electronics equipment, the latter of which is typically powered by onsite solar or wind, backed by batteries. To the extent that a natural gas production facility used grid power, none of the natural gas production facilities identified their facilities as critical load prior to the Event. Only one natural gas production facility participated in a demand response/load as a resource program, and it chose wells that had low production volumes but large electric demand.

Natural gas processing facilities, while more engaged with their electric power providers, still had room for improvement. Eight percent of the sampled processing plants reported being designated as critical load prior to the Event, and during the Event, at least two more processing facilities attempted to obtain critical load designation to aid in power restoration. As with production facilities, processing facilities' energy demands, and back-up generation availability vary. Among the pipelines sampled by the Team, 10 of 32 indicated that one or more of their facilities had been designated as critical loads prior to the Event, but after the Event, 19 intended to update or initiate critical load designation with their local distribution utilities. Many pipeline facilities also have backup power sources, such as diesel back-up generators, for control centers, and solar panels for meter stations.

ISO-New England: Case Study in Gas-Electric Coordination

Given recent industry retirements of coal, oil, and nuclear generating units, ISO New England's (ISO-NE's) resource fleet increasingly relied on a constrained regional natural gas infrastructure, designed, and built primarily to support local gas distribution load. Given its reliance and dependence on the natural gas system, over the course of many years ISO-NE personnel have established procedures and developed tools and processes, all of which are constantly reviewed and evaluated for improvement.

A primary goal of ISO-NE gas-electric coordination operations has been to enhance situational awareness. Aided by Order No. 787,[143] ISO-NE has established unfettered communication and information exchange between ISO-NE operating personnel and regional interstate natural gas pipeline operators. ISO-NE and the

[143] Order No. 787, November 15, 2013 (https://www.ferc.gov/sites/default/files/2020-06/RM13-17-000_0.pdf) "amends the Commission's regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system."

interstate pipelines on which it relies share information through regular, non-emergency, communications based on established processes for both gas and electric system reliability needs.[144] For example, ISO-NE will email expected electric sector gas consumption hourly load profiles to the interstate natural gas pipelines. Pipeline operators, having been given generator burn profiles ("burn rates") and the generating units' required amount of gas nominations, based on MW commitments, are able to notify ISO-NE system operators when scheduled generating units have not secured or nominated adequate gas capacity.

ISO-NE control room personnel have established and maintained relationships with regional interstate pipeline control rooms through constant, daily interaction to achieve a high level of communication and understanding among gas and electric operators. ISO-NE control room personnel communicate daily with their contacts for the generating units to discuss fuel plans and other pertinent operational information.[145]

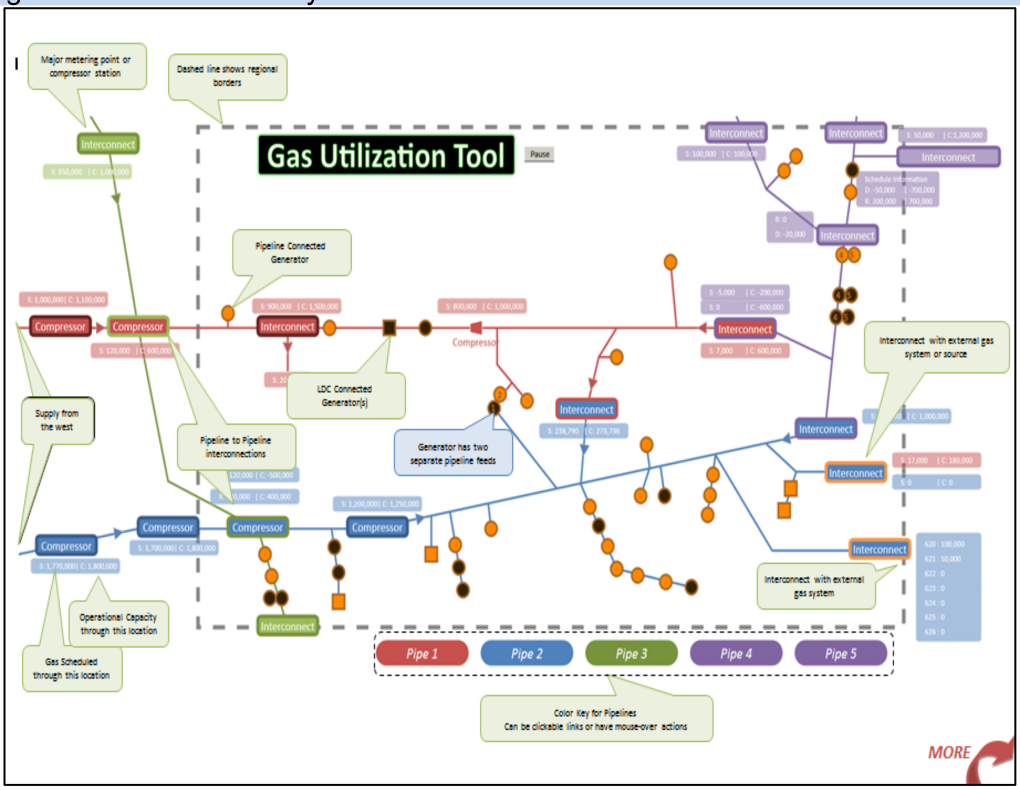
ISO-NE management established relationships and communication protocols with the New England states' governors and Federal and local representatives. These relationships and communications provide familiarity and coordination when the ISO needs to initiate customer appeals and demand management actions. ISO-NE holds semi-annual, pre-seasonal training/outreach activities with market participants and regional regulators, including environmental air regulators, to preview anticipated conditions and available emergency actions; highlight shared responsibilities; and enhance understanding of roles during system emergencies. ISO-NE staff have developed specialized situational awareness tools, in recognition of the fact that on some constrained days they may be operating on a very narrow margin. The Gas Utilization Tool (GUT) (see Figure 26, below, for a screen shot), developed in-house by ISO-NE staff, allows ISO-NE operations personnel to monitor the New England regional interstate pipeline system and provides real-time gas-electric system interface situational awareness by incorporating publicly-available interstate pipeline EBB data, gas schedules for individual generating units (nominations and long/short positions) and other pertinent information. This data is converted into an operator-friendly display (located on the ISO-NE control room floor), which allows for improved situational awareness and seamless access to actionable information. ISO-NE employed individuals with gas sector experience to

[144] OP-21, Appendix B - Electric/Gas Operations Committee's (EGOC) Operations Communications Protocol, https://www.iso-ne.com/static-assets/documents/2014/08/op21b_rto_final.pdf

[145] Information obtained from fuel plans and results of fuel surveys allows for an enhanced awareness of the fuel inventories (estimated number of days each generator is able to run at a specific level) and emissions limitations of the region's generation fleet, and are used in the operations planning processes, as well as in real-time operations, as necessary. In addition to the enhanced situation awareness of ISO-NE operators, fuel surveys inform the ISO New England Operating Procedure No. 21 - Operational Surveys, Energy Forecasting & Reporting and Actions During an Energy Emergency process, which in turn provides public alerts to market participants and regional stakeholders, as well as Federal and Regional (ISO-NE States) regulators and officials.

gather and interpret this data with the purpose of improving situational awareness for ISO-NE operations, which led to the development of the GUT.

Figure 26: Natural Gas System Visualization Tool – GUT[146]



ISO-NE's natural gas-fired generating units are very dependent on the regional liquid natural gas (LNG) facilities, so ISO-NE also actively monitors LNG tankers shipments and traffic, using the Marine Traffic website,[147] to anticipate fuel availability and adjust operating plans. ISO-NE operators have learned to understand the relationships between LNG tanker traffic and fuel availability for ISO-NE's generation fleet over several years of continuous monitoring and real-time operations experience.

To anticipate and prepare for potential energy adequacy issues, ISO-NE developed Operating Procedure No. 21 – Operational Surveys, Energy Forecasting & Reporting and Actions During an Energy Emergency (OP-21).[148] In addition to the specific Generator Winter Readiness Survey requirements, OP-21 establishes procedures for forecasting and declaring Energy Alerts and Energy Emergencies

[146] NERC Natural Gas and Electrical Operational Coordination Considerations Reliability Guideline, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Gas_Electric_Guideline.pdf.
[147] MarineTraffic: Global Ship Tracking Intelligence | AIS Marine Traffic , which among other features, has a live map showing the location of global merchant shipping, based on satellite and other data.
[148] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf

based on a 21-day hourly look ahead at expected energy availability. ISO-NE Energy forecasting and reporting incorporates data from the Generator Fuel and Emissions Surveys, conducted weekly in the winter months and bi-weekly in non-winter months, with increased frequency, as necessary. OP-21 includes established thresholds (e.g., FMLCC2,[149] FEEA1 through FEEA3[150]) to communicate potential reliability issues to regional stakeholders; specific criteria to trigger Alert[151] and Emergency[152] declarations and associated actions by the ISO, TOPs' Local Control Centers (LCCs) and contacts for the generating units, intended to help mitigate emergencies. Through the requirements laid out in OP-21, ISO-NE takes an active coordinating role in ensuring that critical infrastructure of the interstate natural gas pipeline system is not served by electrical transmission or distribution circuits that may be subject to automatic or manual load shedding schemes. Through the requirements laid out in OP-21, ISO-NE takes an active coordinating role in ensuring that critical infrastructure of the interstate natural gas pipeline system is not served by electrical transmission or distribution circuits that may be subject to automatic or manual load shedding schemes. ISO-NE facilitates the exchange of pertinent information through sharing the results of the annual Natural Gas Critical Infrastructure Survey of each interstate natural gas pipeline company operating within New England, and LNG facilities serving the region, with New England's LCCs for their review of load shedding plans. ISO-NE also takes actions to ensure that dual-fuel resources will be able to perform when needed, including unit testing and assessment of alternate fuel availability.[153]

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149 Available resources for any hour during the 21-day forecast are expected to be less than 200 MW above those required to meet Operating Reserve requirements. Every hour during the 21-day forecast must be designated either "normal" or one of the thresholds.

150 Available Resources during any hour of the Operating Day are forecasted to be less than those required to meet Operating Reserve requirements, and implementation of OP-4 Actions 1 through 5 (FEEA1), OP-4 Actions 6 through 11 (FEEA2), or OP-7, firm load shed (FEEA3), is being forecasted.

151 Example of an Energy Alert Declaration Criteria: "FEEA2 or FEEA3 is forecasted to occur in at least 1 hour on 1 or more consecutive days in days 6 through 21 of the 21-day energy assessment."

152 Example of an Energy Alert Emergency Criteria: "FEEA2 or FEEA3 is forecasted to occur in at least 1 hour on 1 or more consecutive days in days 1 through 5 of the 21-day energy assessment," or "Shedding of firm load under OP-7 is occurring or is anticipated to occur due to an actual energy deficiency resulting from a sustained shortage of fuel availability or deliverability to, or sustained environmental limitations on some or several of New England Resources."

153 *See*, *e.g.,* Oil-Depletion and Usable-Oil Inventory Graphs https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/oil-depletion-graphs.

B. February 8-13: Freezing Precipitation and Temperatures Begin to Fall, Causing Generation Outages; Weather Expected to Worsen Next Week

- *Temperatures and Freezing Precipitation Begin to Fall*
- *Electricity Demands Increase*
- *Unplanned Generation Outages Increase*
- *Natural Gas Production Declines*
- *Weather Expected to Worsen Next Week*

Unlike an event where a disturbance on the BES occurs over a matter of a few minutes,[154] the Event spanned many days. The Event, characterized by an unanticipated and intolerable number of unplanned outages of BES generation during peak winter load conditions, actually started during the week of February 7, 2021 as ambient temperatures began to drop below 32 degrees in ERCOT, MISO, and SPP.

1. Event Area Cold Weather Conditions – February 8 – 13

While the northern areas of both SPP and MISO were already experiencing colder temperatures, in southern SPP, the leading edge of an arctic air mass moved through northeast Oklahoma into central Oklahoma during the pre-dawn hours on Monday, February 8. Sub-freezing temperatures with freezing drizzle began across parts of western Oklahoma into Oklahoma City at 7 a.m. on the morning of February 8.[155] The cold air slowly moved across the rest of the state by Wednesday, February 10. The cold air remained in place statewide through the weekend of February 13 –15.

In ERCOT, the arctic air likewise moved into north Texas during the pre-dawn hours on Monday, February 8. On this day, the ERCOT meteorologist began to understand that the next week's weather could be extremely cold, writing "[t]his is the most challenging, worrisome forecast since I joined ERCOT," and comparing the expected polar vortex disruption to the 1989 and 2011 storms, both of which caused thousands of MW of unplanned generation outages in ERCOT.[156] The cold air slowly moved into northern and central Texas by Wednesday, February 10. The Dallas-Fort Worth area experienced freezing rain on the evening of Wednesday, February 10, into Thursday, February 11. By the evening of February 11, the cold air had pushed into the entire state of Texas, and freezing rain and sleet reached almost as far south as San Antonio. The cold air remained entrenched statewide from Friday, February 12, through the weekend. On Saturday, February 13,

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[154] Arizona-Southern California Outages on September 8, 2011 Causes and Recommendations) https://www.ferc.gov/sites/default/files/2020-07/Arizona-SouthernCaliforniaOutagesonSeptember8-2011.pdf

[155] Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION "*Oklahoma Winter Storm and Arctic Outbreak of February 10th-19th, 2021*" (February 20, 2021) (data provided by NOAA Team members).

[156] UT Report at 92, *see also* Figure 11, above and 2011 Report at 172-179.

there were a few reports of light freezing rain near Dallas, with widespread light freezing rain near Austin and San Antonio, and even to the coast between Houston and Corpus Christi.[157]

In MISO South, the arctic air mass moved into northern Arkansas on Wednesday, February 10, approximately two days after it reached ERCOT and SPP. Ice storm warnings and winter weather advisories went into effect that evening through February 11 for freezing rain and sleet. Roads became hazardous from near Little Rock eastward, and the most intense areas of frozen precipitation led to power outages. At least half an inch of sleet piled up roughly halfway between Little Rock and Memphis, at the Little Rock Air Force Base, and at Sherwood, in the center of the state. Freezing drizzle was also reported across southern Arkansas on the morning of February 12. The cold air remained in place statewide for the next several days.[158] The cold front moved through the state of Louisiana on late Wednesday, February 10 into Thursday, February 11. Cooler air rushed southward into Louisiana and resulted in a light icing on February 12. The cold front moved southeast across the state of Mississippi during the early morning hours on Thursday, February 11. Along with the colder temperatures, an initial wave of precipitation in the form of freezing rain occurred across northwestern parts of Mississippi during the morning of February 11.[159] Northwestern Mississippi received up to a quarter inch of freezing rain, which caused trees and power lines to sag under the weight of the ice. A minor freezing rain event hit northeastern Mississippi on February 13, with accumulations of less than a tenth of an inch.[160]

2. Electricity Demands and Energy Needs Increase

As the weather turned colder, the demand for electricity in each of the BA footprints increased during the week of February 7. Figure 27, below, shows how system demands increased as a percentage of each BA's all-time previous winter peak loads in the Event Area.

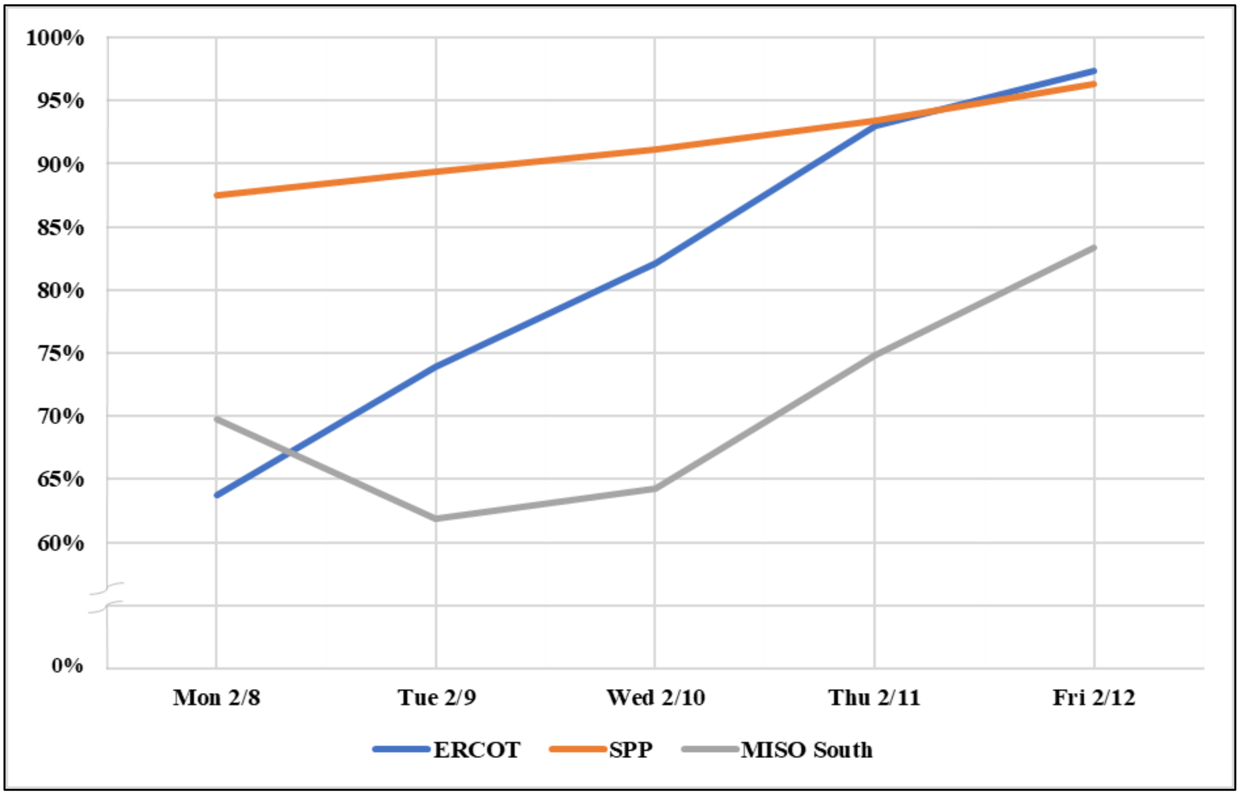
157 Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION "Texas Winter Storm and Arctic Outbreak of February 10-19th, 2021" (February 19, 2021) (data provided by NOAA Team members).

158 Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION *"Arkansas Winter Storm and Arctic Outbreak of February 10th- 20th, 2021"* (February 26, 2021) (data provided by NOAA Team members).

159 Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION "*Louisiana Winter Storm and Arctic Outbreak of February 10th-19th, 2021*" (February 22, 2021) (data provided by NOAA Team members).

160 Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION "*Mississippi Winter Storm and Arctic Outbreak - February 11th-19th, 2021*" (February 24, 2021) (data provided by NOAA Team members).

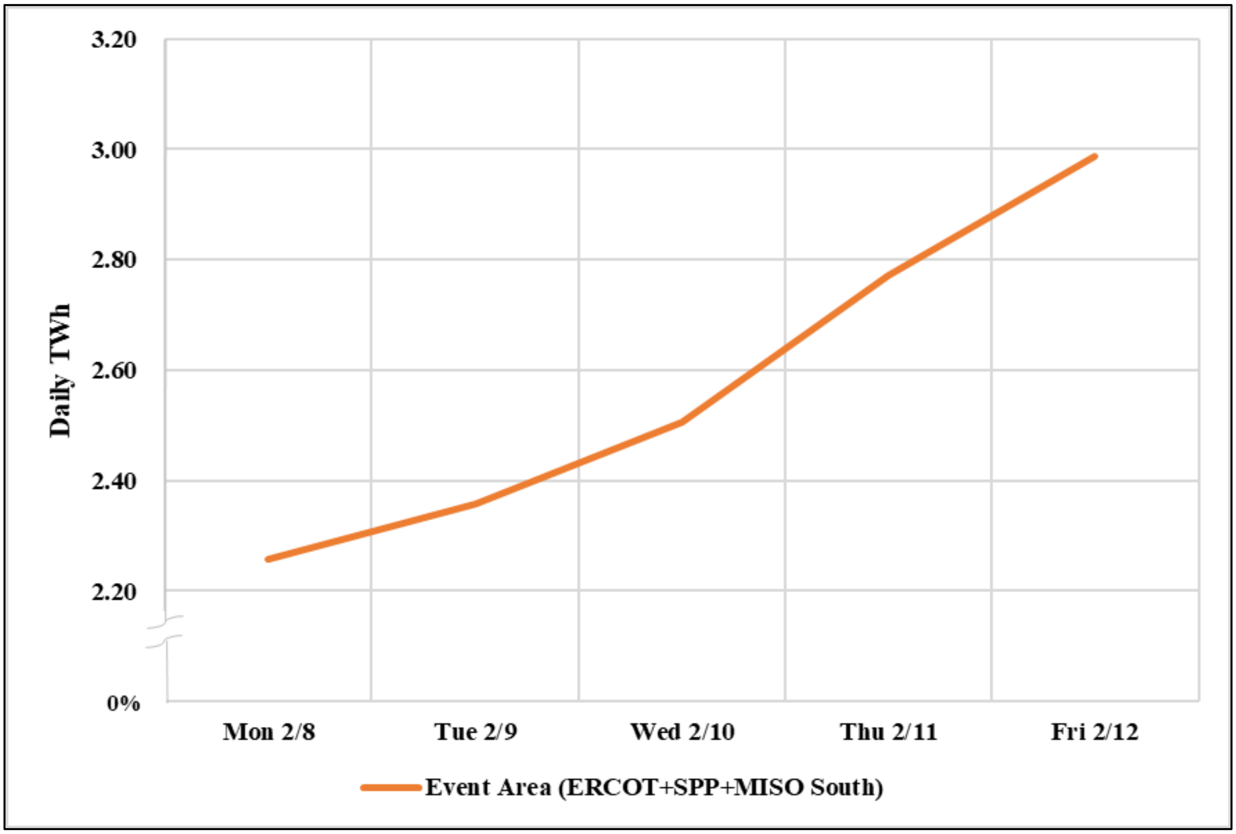
Figure 27: Mon-Fri, February 8-12: ERCOT, SPP and MISO South Daily Peak System Loads as Percentage of All-Time Previous Winter Peak Loads



By Thursday, February 11, ERCOT's and SPP's peak loads had already exceeded well over 90 percent of their previous winter peak loads. By Friday, February 12, both had exceeded 95 percent of their previous winter peak loads.[161] The combined energy needs for the Event Area increased by 32 percent, or nearly a third, from Monday to Friday, as shown in Figure 28 below.

[161] Both ERCOT and SPP previously reached all-time winter peaks of 65,750 MW and 43,584 MW, respectively, on January 17, 2018.

Figure 28: Mon-Fri, February 8-12: Increase in Energy Needs in the Event Area[162]



3. Colder Temperatures and Freezing Precipitation Begin to Impact Electric and Natural Gas Infrastructure

The below-freezing temperatures and freezing precipitation that moved into Oklahoma and Texas during the week of February 7 substantially decreased generating unit availability. Some of those generating units remained out of service and contributed to generation shortfalls during the week of February 14, when the winter peak load conditions and firm load shed occurred. See Figure 66b, below.

a. Generating Unit Freezing Issues – February 8 – 13

i. Wind Turbine Generator Freezing Issues

Wind turbine generators were the largest share of individual generating units that suffered freezing issues from February 8 to 10. Precipitation and condensation during cold weather can cause layers

[162] In Terawatt-hours (equal to 1,000 GWh).

of ice to form on turbine blades, causing balancing, bearing, and other equipment problems. Blade icing caused outages, derates or failures to start in southern SPP on February 8 and 9 (shown in Figures 29 and 30, below), followed by ERCOT on February 10 (shown in Figures 31 and 32, below). From approximately February 8 at 3:15 a.m. to February 9 at 4:15 a.m., 102 distinct generating units in SPP experienced a total of 123 generating unit outages, derates or failures to start; ice build-up on the turbine blades caused 48 outages or derates at 41 wind facilities, while temperatures below turbine operating limits causing seven derates at four wind facilities (see Figure 31, below). Cold weather-related issues affecting wind generating units accounted for 6,810 MW (nameplate), or 52 percent of the outaged generation during this period.

Figure 29: SPP Generation Outages and Derates (MW) by Cause, Wind Generating Units, February 8, 3:15 a.m. - February 9, 4:15 a.m.

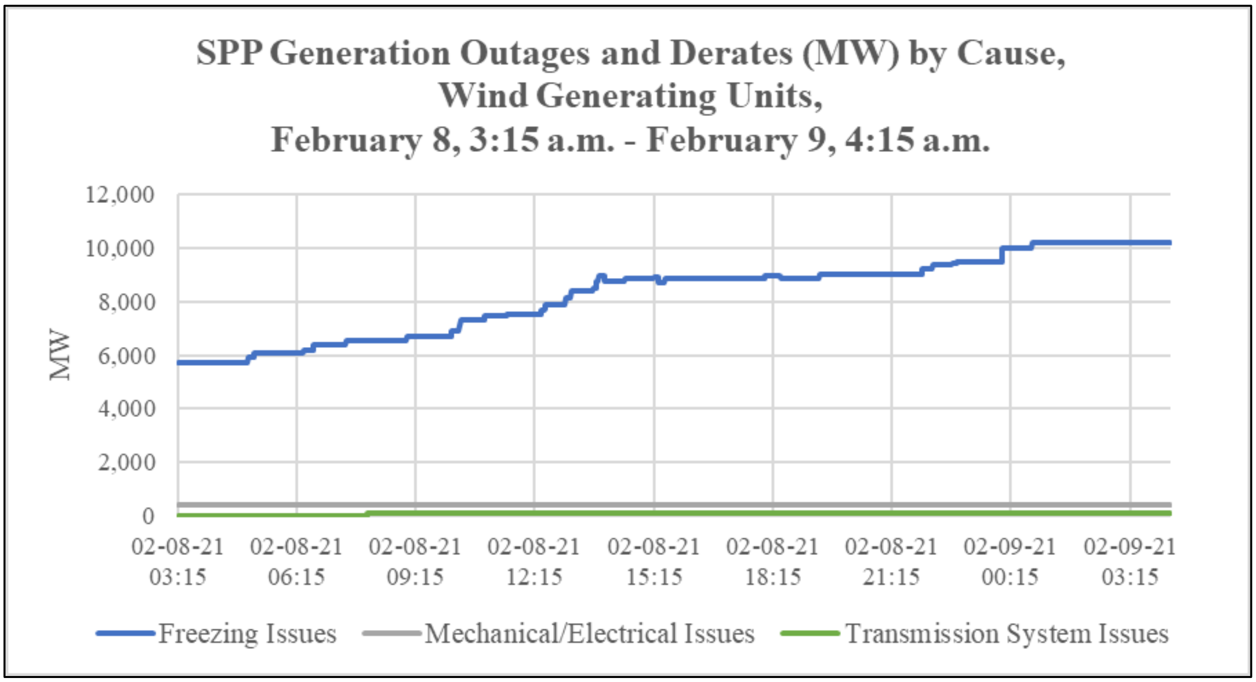
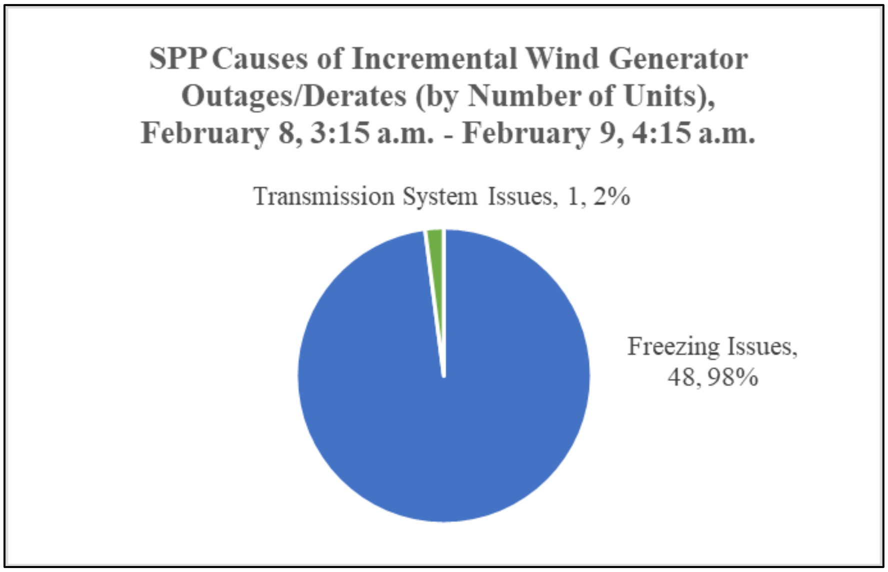
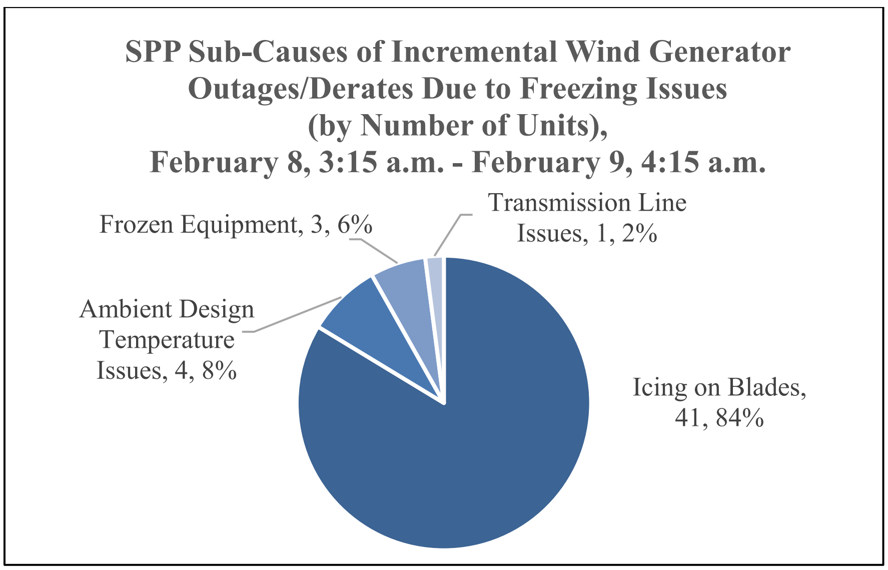


Figure 30: SPP Footprint: Wind Generator Outage and Derate Causes





In ERCOT, beginning at around midnight on February 10, 89 individual generating units experienced 107 outages, derates, and failures to start, 72 percent of which were wind (totaling 8,900 MW (nameplate)). Essentially all of the wind outages were due to icing on blades (see Figure 32, below). At about 7:00 a.m. on February 10, the wind generation outages and derates escalated, particularly due to icing on the blades. For the ERCOT footprint, Figure 31, below illustrates the trend in increased wind generation outages, and Figures 31 and 32 show the causes of wind generation outages and derates.

Figure 31: ERCOT Generation Outages and Derates (MW) by Cause, Wind Generating Units, February 10, 12:00 a.m. – 2:30 p.m.

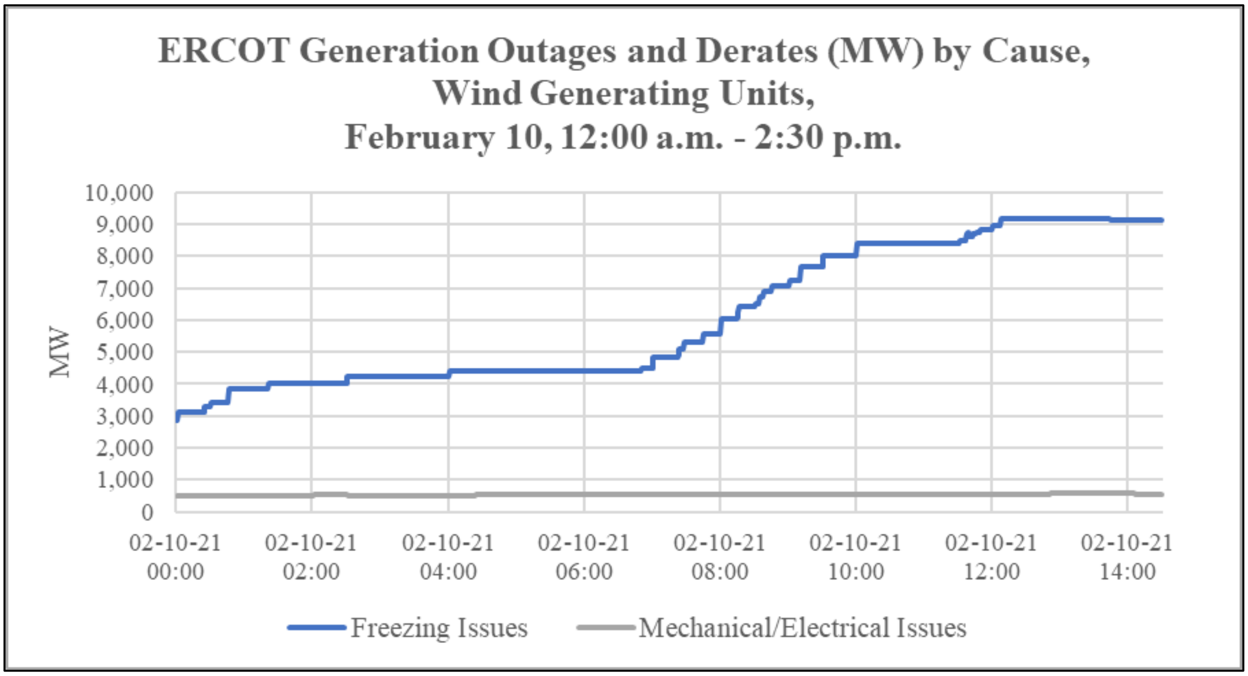
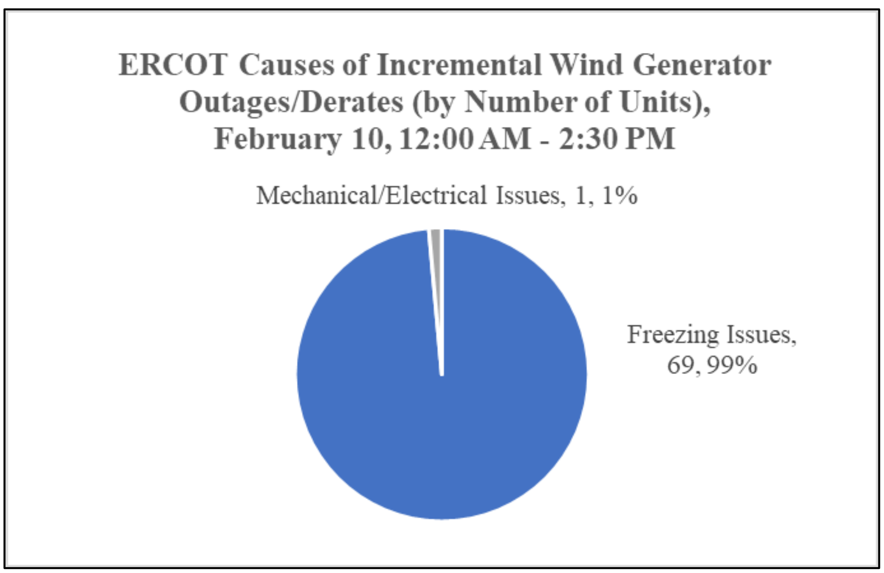
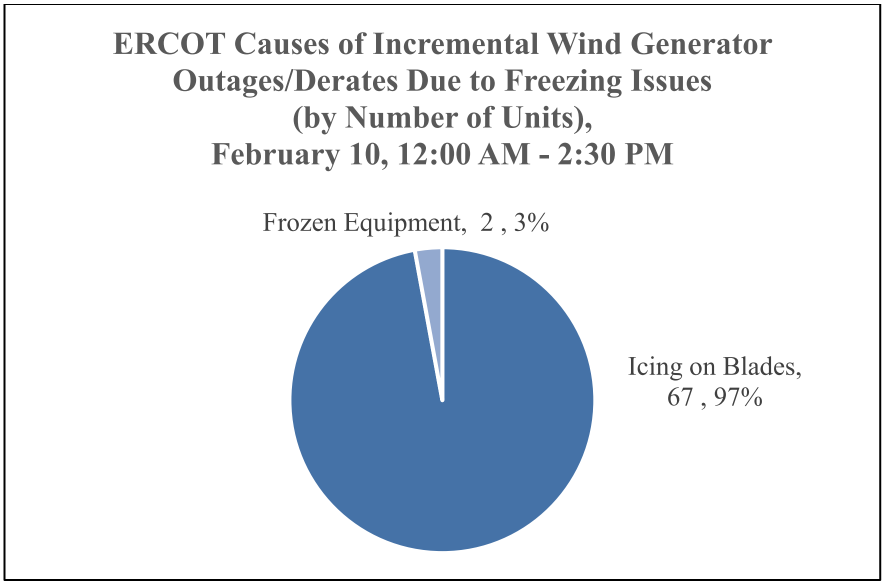


Figure 32: ERCOT Footprint: Wind Turbine-Generator Outage Causes





Figures 33 and 34 show the distribution of generation outages and derates in the Event Area on February 10 at 2:30 p.m., by cause and by fuel type, respectively.

Figure 33: Location of Unplanned Generation Outages and Derates (MW Outaged) by Cause, Total Event Area, February 10, 2:30 p.m.

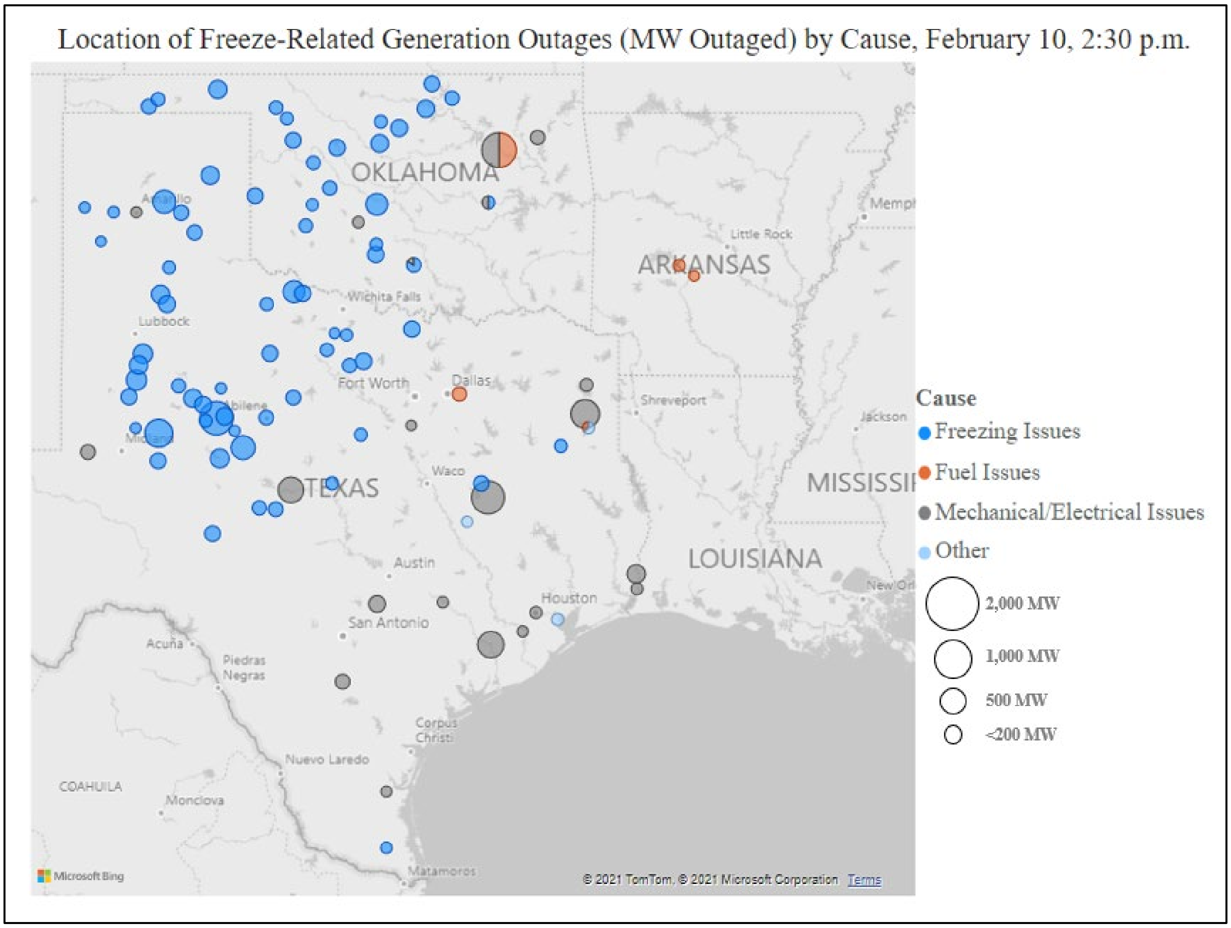
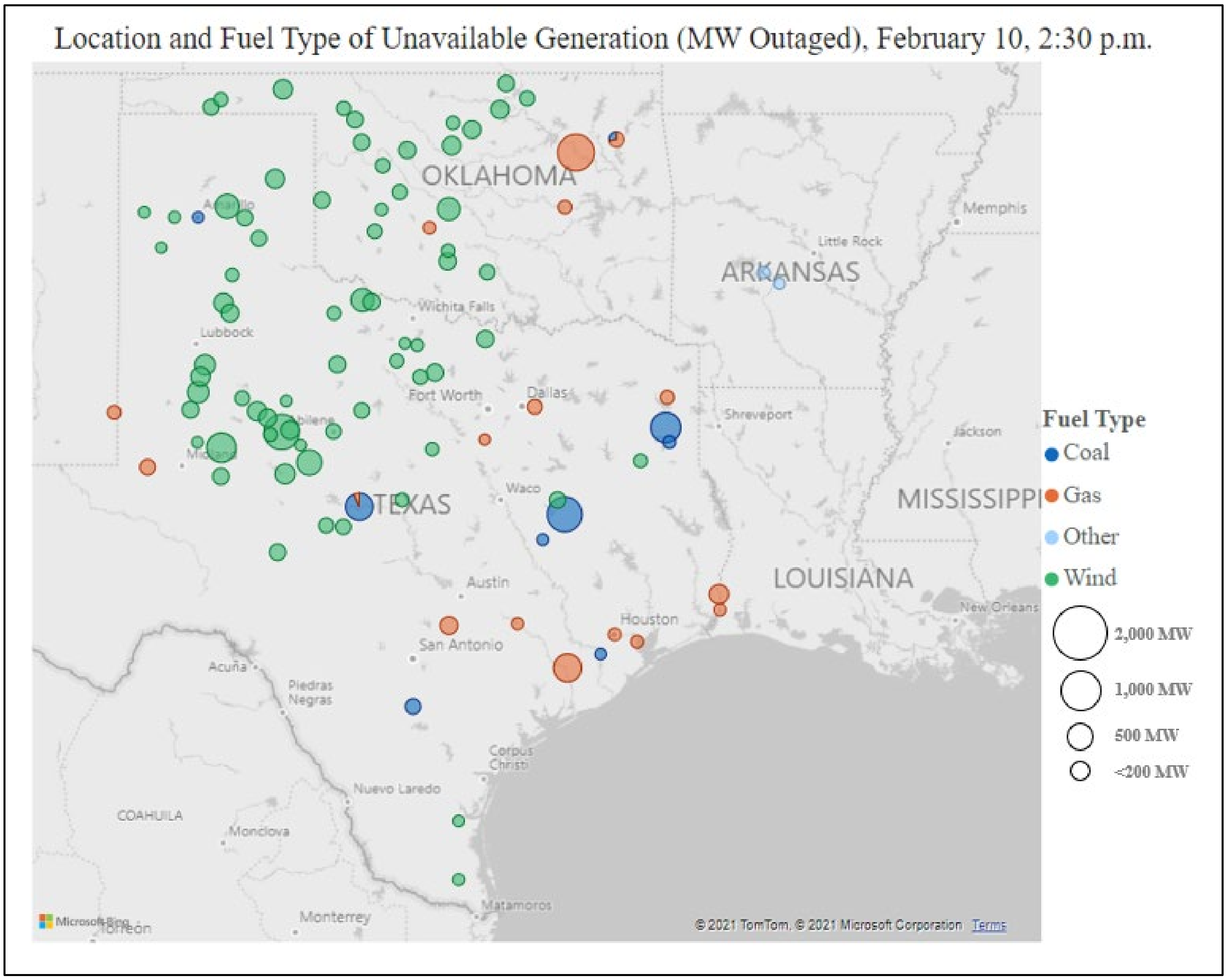


Figure 34: Location of Unplanned Generation Outages and Derates, (MW Outaged), by Fuel Type, Total Event Area, February 10, 2:30 p.m.



In ERCOT, the outaged wind generation remained offline until the ambient temperatures rose above freezing, allowing ice on the turbine blades to melt, which did not occur until late in the week of February 14.

ii. Other Types of Generator Freezing Issues

To a lesser degree, other types of generating units were also affected by freezing issues during the week of February 7. In SPP, primarily in the southern parts of Oklahoma, Kansas and Texas, natural gas, coal/lignite, and oil/distillate generating units experienced outages, derates, and failures to start. Frozen equipment, transmitters, sensing lines, valves, and inlet air systems all contributed to the freeze-related events. Outages due to freezing issues in natural gas, coal/lignite and oil/distillate generating units in SPP totaled 3,425 MW during the week of February 7. In addition to the generating unit outages directly attributed to freezing in SPP, all unplanned generating unit outages increased as temperatures decreased. In addition to the 3,425 MW, there were 3,680 MW of additional mechanical/electrical outages by the end the week of February 7. In ERCOT, during the week of February 7, natural gas-fired generators experienced outages, derates and failures to start due to freezing issues, with losses totaling approximately 4,722 MW, and mechanical/electrical outages increased by 4,675 MW by the end the week of February 7.

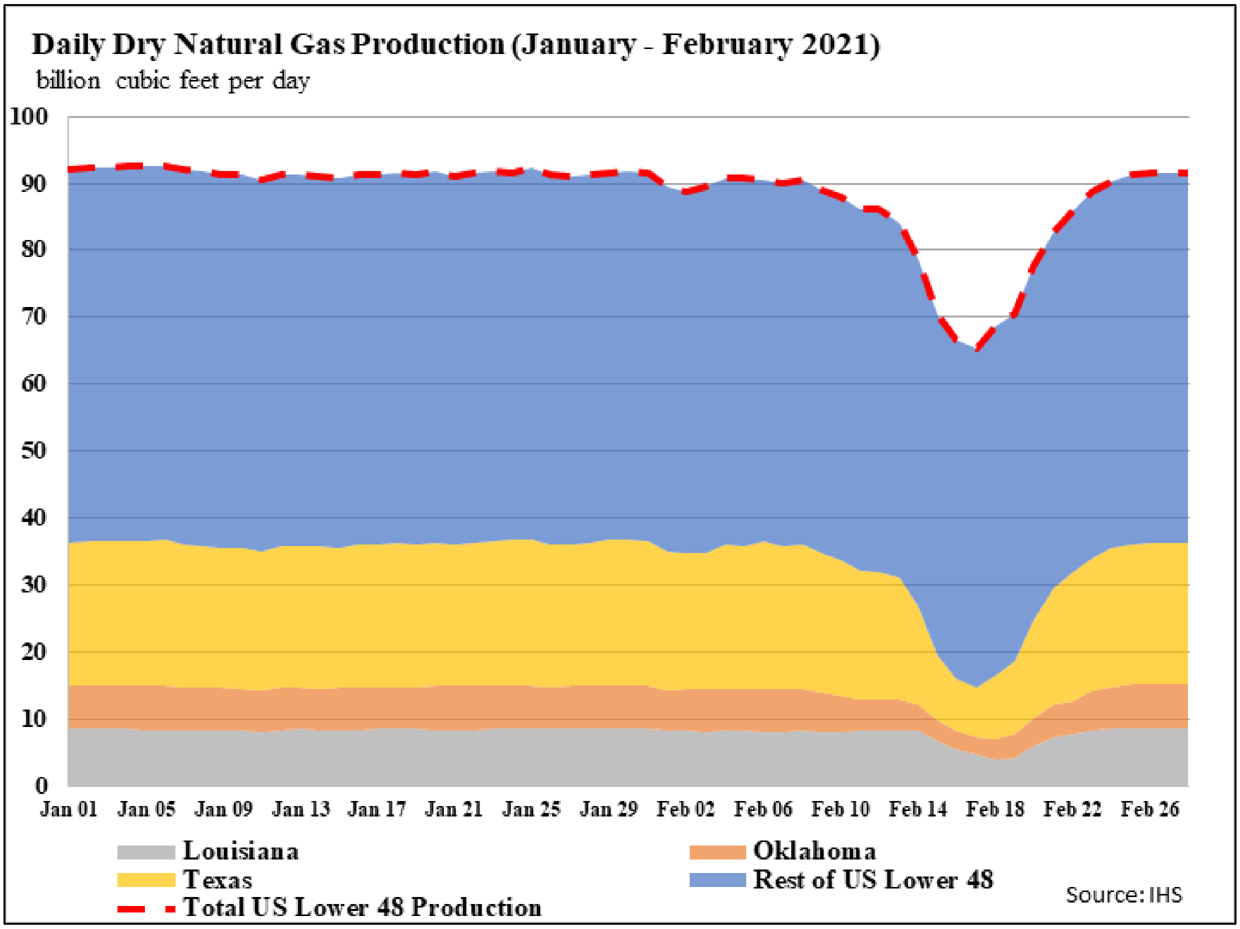
b. Natural Gas Production Cold Weather Issues - February 8 - 13

i. Natural Gas Production Declines Begin at Wellheads

Natural gas production in Texas, Oklahoma, and Louisiana was relatively flat or level from January 1, 2021 through February 7, 2021. During the Event, unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins to prevent imminent freezing issues, as well as unplanned outages of gathering and processing facilities, resulted in a decline of natural gas production. As shown in Figure 35, below,[163] production began to decline first in Oklahoma and Texas beginning on approximately February 7 and continued to decline as the week progressed.

[163] Figure 35 is based on raw data provided by IHS, from which the Team prepared the Figure.

Figure 35: Daily Dry Natural Gas Production (January - February 2021)



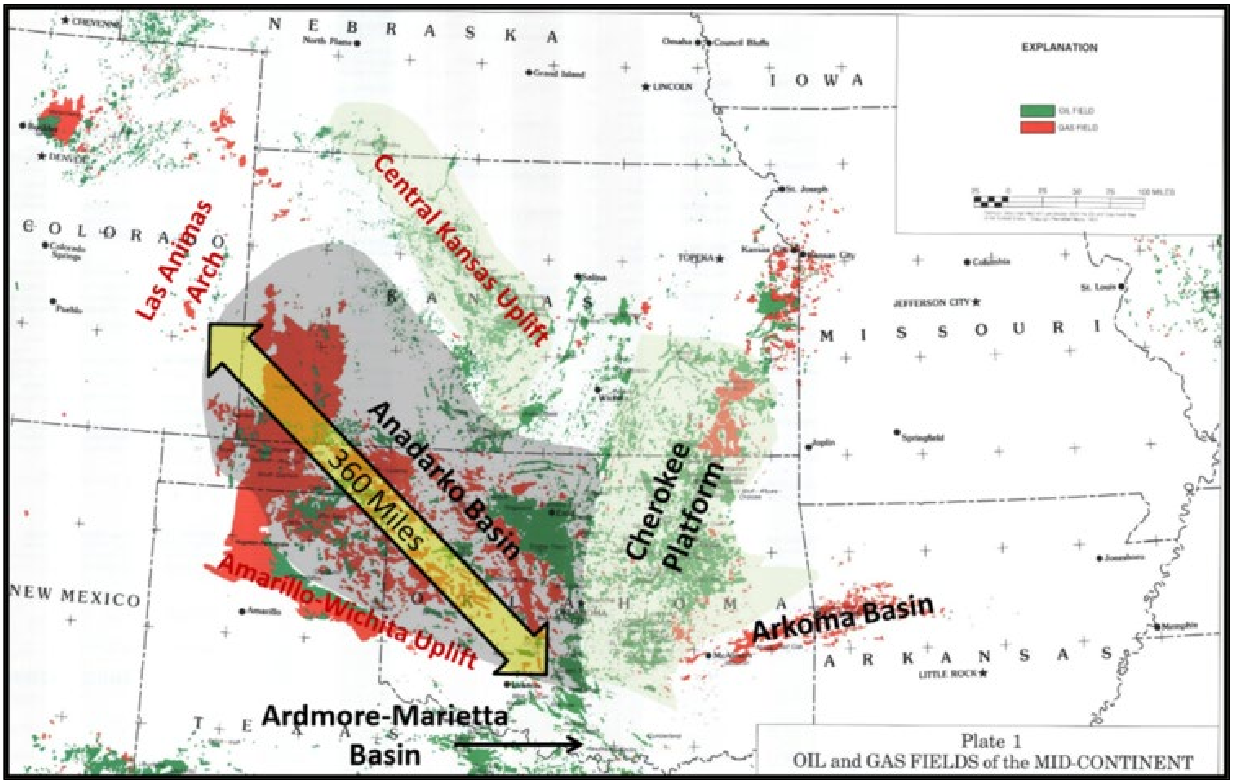
Before the severe cold weather began, available natural gas supply was sufficient to meet firm supply and transportation commitments. Some natural gas production facilities were out of service primarily due to mechanical/electrical problems. Most of these pre-existing (i.e., prior to February 8) natural gas production facility outages continued throughout the Event.

Any increased demands for natural gas, such as from residential heating needs or BES natural gas-fired generators, would need to be met by:

- increasing withdrawals from natural gas in storage during the Event,
- importing natural gas into the Event Area, or
- curtailing non-firm contract customers (e.g., generating units with non-firm transportation, interruptible industrial customers).

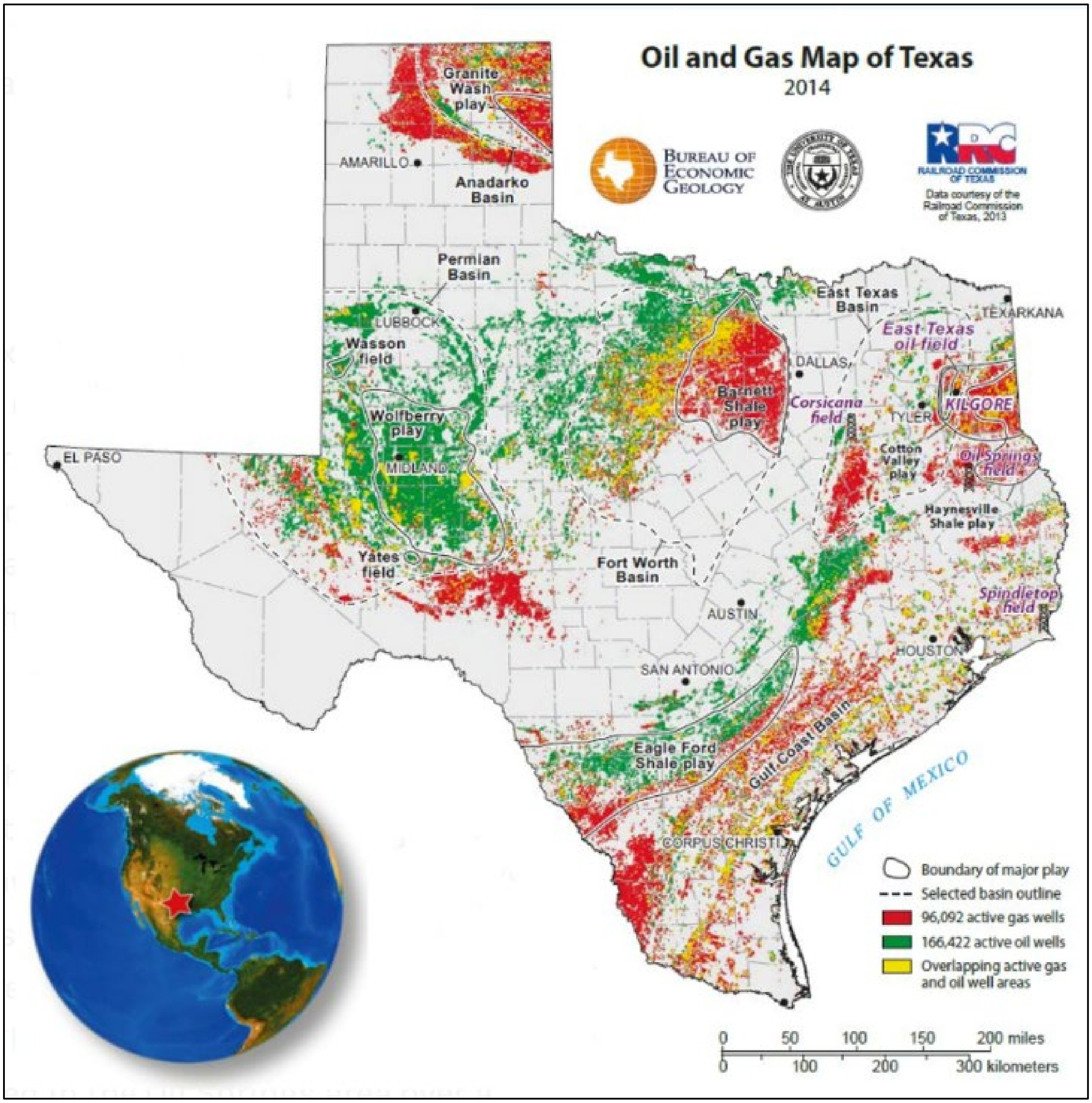
As shown in Figure 35, above, beginning on approximately February 7, as sub-freezing temperatures hit Oklahoma and Texas, home of the Anadarko, Permian and other important natural gas production basins (depicted in the following Figures 36 and 37), total natural gas production in the Event Area began to decline due to increased natural gas production facility impairments.

Figure 36: Anadarko and Arkoma Basins[164] Geographic Location



164 Anadarko Basin, Rascoe & Hyne, 1988

Figure 37: Texas Basins[165] Geographic Location

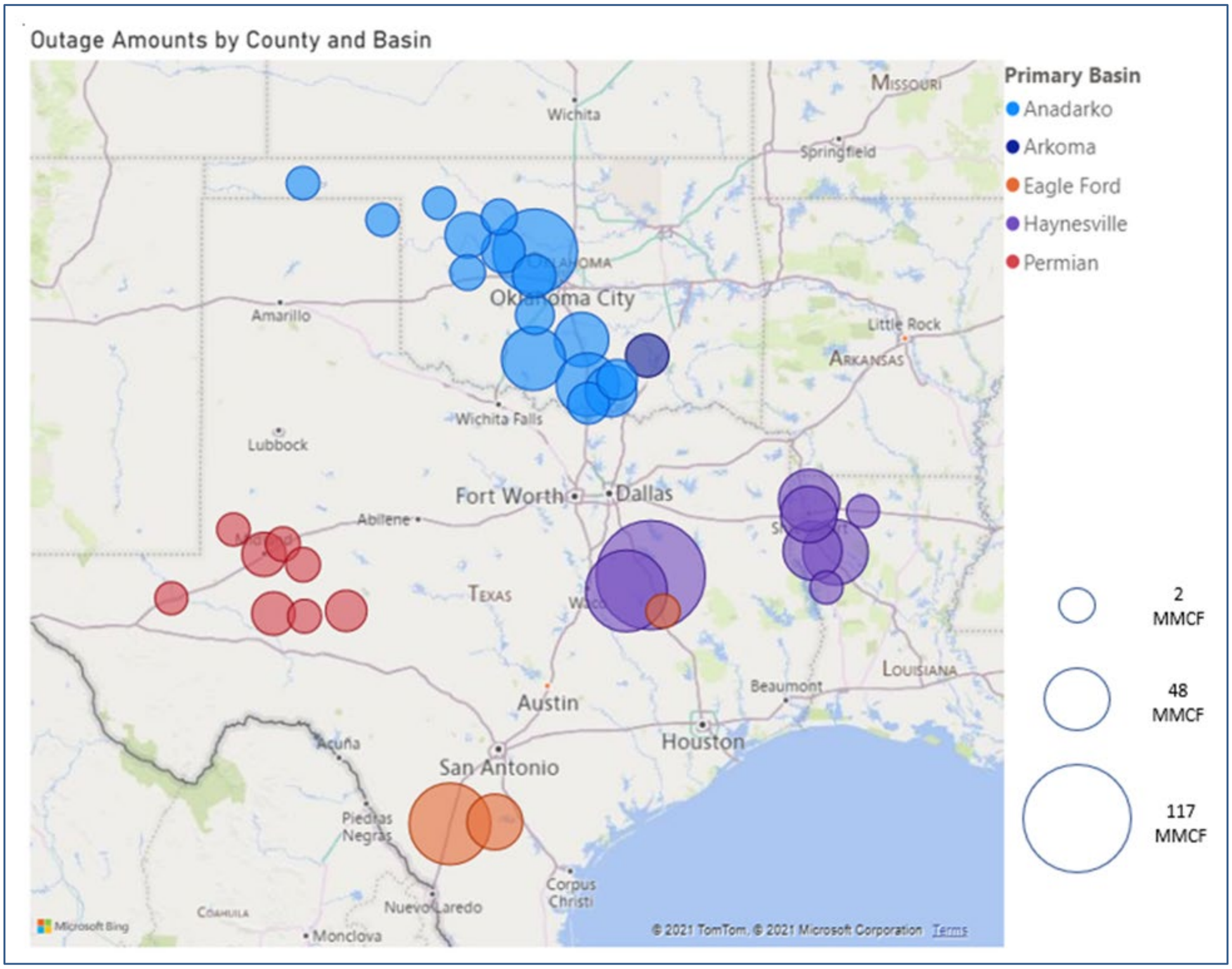


After February 7, natural gas pipeline data showed an increasing discrepancy between the amount of gas nominated and shipped, which resulted in increased pipeline critical notices to maintain pipeline system integrity. Figures 38a and 38b through 39a and 39b below show the locations and causes for producer outages on February 11 and 12 (again, the top figure in each pair shows the outages by

[165] Anadarko Basin, Rascoe & Hyne, 1988.

basin, while the bottom figure shows the causes as provided by the sampled producers), which can be compared with the baseline of February 5 in Figure 25a and 25b, above.

Figure 38a: Natural Gas Production Volumetric Outages by Primary Basin, February 11, 2021[166]



[166] All outage events smaller than 1 MMCF are excluded from figure.

Figure 38b: Natural Gas Production Volumetric Outages by Primary Cause, February 11

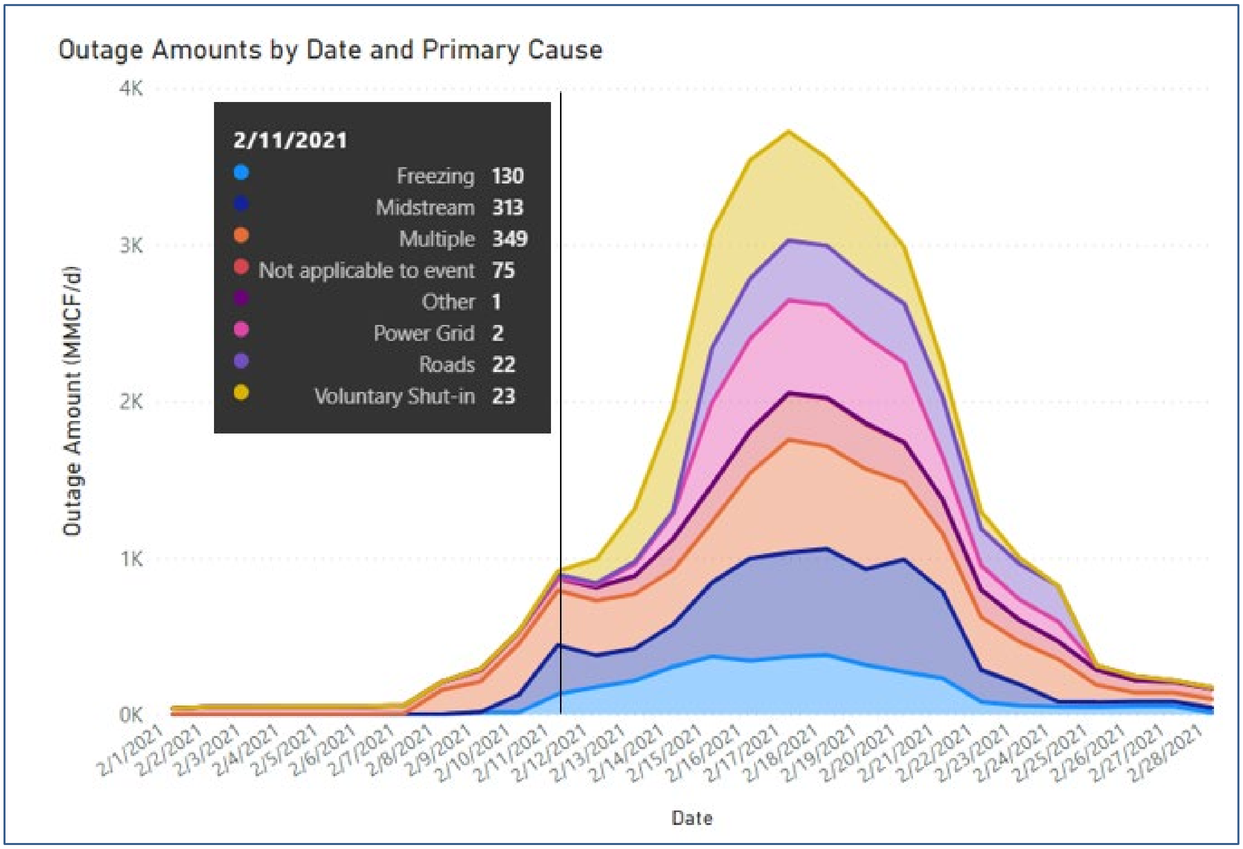
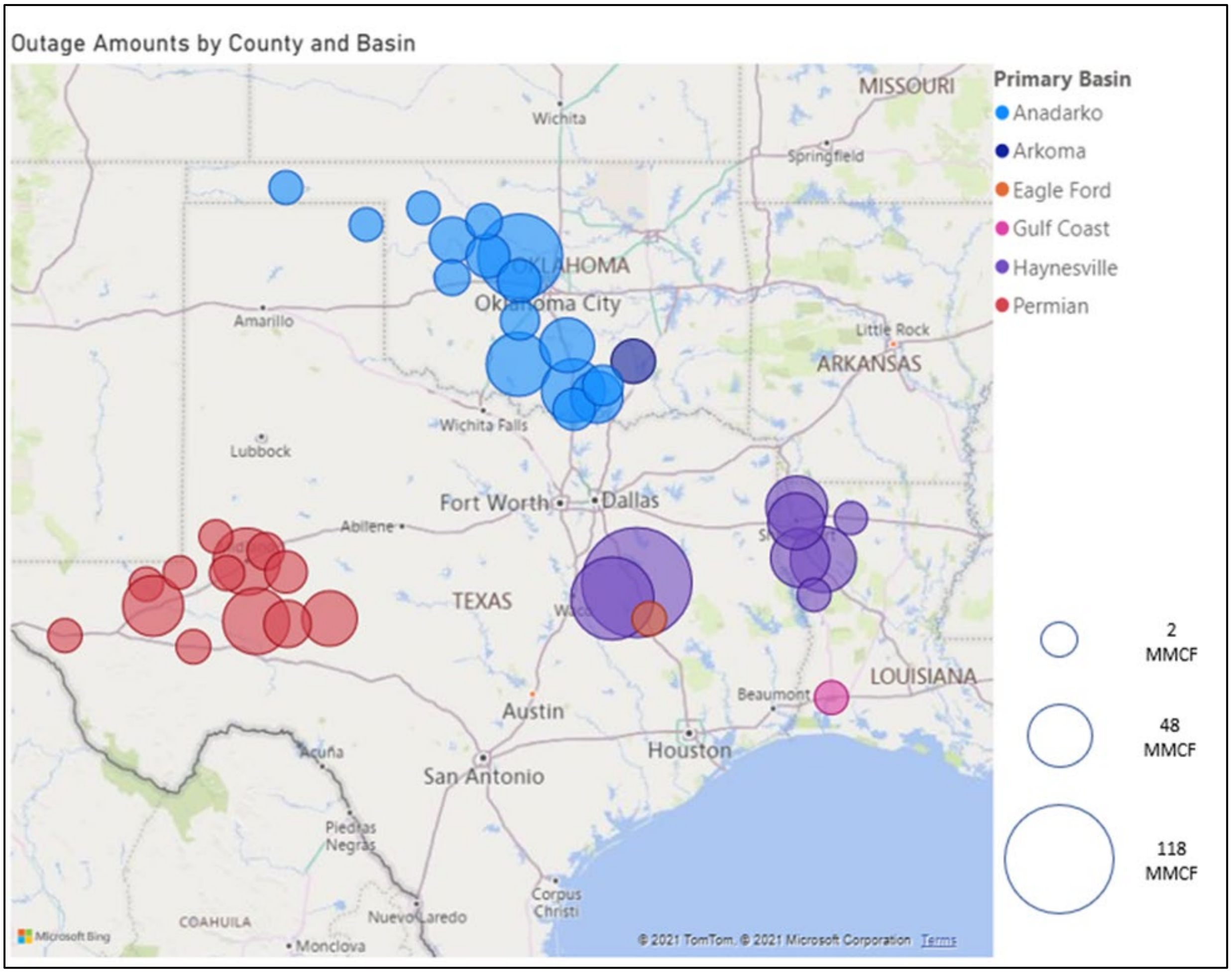
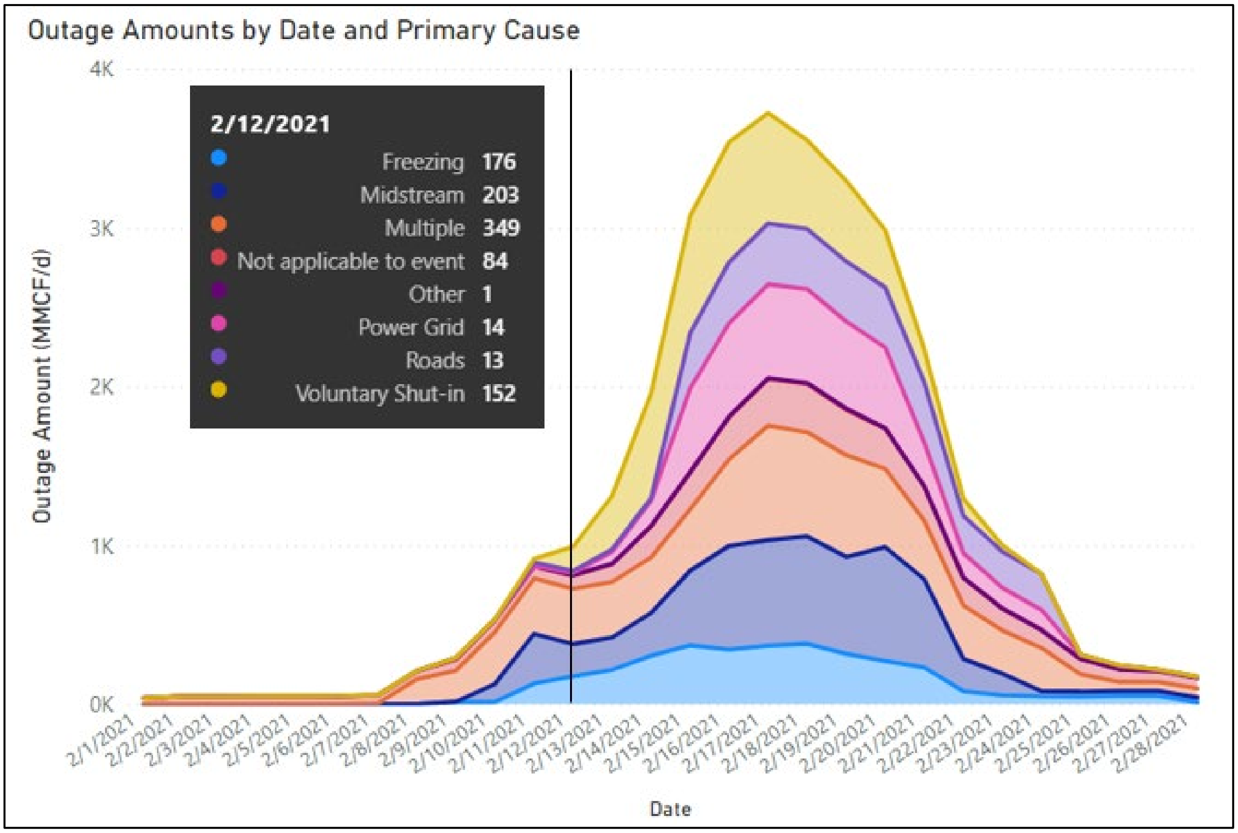


Figure 39a: Natural Gas Production Volumetric Outages by Primary Basin, February 12[167]



[167] All outage events smaller than 1 MMCF are excluded from figure.

Figure 39b: Natural Gas Production Volumetric Outages by Primary Cause, February 12



ii. Effect on natural gas processing - February 8 - 13

Natural gas processing facilities also incurred outages and reductions in output the week of February 7, due in large part to reduced production and gathering as shown in Figure 40, below.

Figure 40: Natural Gas Processing Outages and Causes, February 12-14, 2021

Processing Facility Event Causes on February 12

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
100%	Freezing Temperature and Weather Conditions (100% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	93%
		Freezing Issues at Processing Facilities	Processing Facility Disruption	7%
	Loss of Power (0% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	0%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

**There were a total of 14 causes of processing plants events occuring on February 12.*

Processing Facility Event Causes on February 13

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
100%	Freezing Temperature and Weather Conditions (100% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	95%
		Freezing Issues at Processing Facilities	Processing Facility Disruption	5%
	Loss of Power (0% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	0%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

**There were a total of 22 causes of processing plant events occuring on February 13.*

Processing Facility Event Causes on February 14

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
100%	Freezing Temperature and Weather Conditions (85% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	73%
		Freezing Issues at Processing Facilities	Processing Facility Disruption	12%
	Loss of Power (15% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	15%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

**There were a total of 34 causes of processing plants events occuring on February 14.*

iii. Status of natural gas pipelines - February 8 - 13[168]

Pipeline Communications[169]

Interstate pipelines issue a variety of communications and directives to shippers and, pursuant to FERC regulations (18 CFR §284.12 (2021)), post critical notices to describe strained operating conditions, to issue operational flow orders and, when applicable, to make force majeure announcements. Most intrastate pipelines provide similar information and instructions to shippers, either by posting or direct communications.

Critical notices describe situations when the integrity of the pipeline

[168] *See* Appendix L, Primer on Natural Gas Production, Processing, Transportation and Storage for background on natural gas terminology and concepts.

[169] *See* Appendix C for an example of a notice issued by a natural gas pipeline entity during the Event.

system is threatened. A critical notice will specify the reasons for and conditions making issuance necessary, and also state any actions required of shippers. Operational integrity may be determined by use of criteria such as the weather forecast for the market area and field area; system conditions consisting of line pack, overall projected pressures at monitored locations, and storage field conditions; facility status (e.g., horsepower utilization and availability); and projected throughput versus availability, for capacity and supply.

Operational flow orders (OFOs) are used to control operating conditions that threaten the integrity of a pipeline system. (Individual pipeline companies may have other names for operational flow orders such as alert days, performance cut notices or an emergency strained operating condition). OFOs request that shippers balance their supply with their usage daily, within a specified tolerance band. An OFO can be system-wide or apply to selected points. Failure by a shipper to comply with an OFO may lead to penalties. Pipelines may also limit services such as parking and lending of natural gas, no-notice (the provision of natural gas service without prior notice to the pipeline), interruptible storage and excess storage withdrawals and injections.

Force majeure, if authorized by the pipeline's tariff, is a declaration of the suspension of obligations because of unplanned or unanticipated events or circumstances not within the control of the party claiming suspension, and which the party could not have avoided through the exercise of reasonable diligence.

February 6 through February 10, 2021. Several days before the coldest weather hit the Event Area and the need for firm load shed began, intrastate natural gas pipelines in Texas, as well as interstate natural gas pipelines located in Texas, Oklahoma, Kansas, and Louisiana, began issuing critical notices and similar communications related to pipeline system integrity, due to expected cold weather. On February 9, intrastate pipelines in Texas began to issue OFOs to natural gas shippers, requiring them to balance their receipts and deliveries. Also, on February 9, one intrastate pipeline in Texas issued the first of what would be several critical notices, warning that there would be pipeline natural gas delivery restrictions to natural-gas fired generating units with interruptible natural gas transportation contracts in northern Texas area of ERCOT, effective for the February 10, 2021 gas day.[170] On February 10, another critical notice was issued by the same intrastate pipeline company for the February 11 gas day, notifying natural gas-fired generating units with interruptible natural gas transportation contracts in the Austin, Texas area of ERCOT that they would be subject to natural gas delivery restrictions.

Overall, the interstate and intrastate natural gas pipelines surveyed by the Team performed as expected and were largely able to fulfill their firm transportation obligations. They were not significantly affected by the cold weather and freezing conditions. They were only minimally

[170] The gas day is from 9:00 a.m. through 8:59 a.m. Central Prevailing Time for the entire United States.

affected by power outages because most have gas-fired compressors, redundant compression, and backup power.

February 11 through 13. Increasing numbers of intrastate and interstate pipelines issued critical notices and OFOs advising shippers to stay within their nominations to protect the integrity of their systems and restricting interruptible transportation service to some natural gas-fired generating units in ERCOT. Also, during this timeframe, pipelines issued notifications that placed limitations on natural gas storage withdrawals under interruptible contracts. These notices were issued in recognition of declining natural gas supply.

iv. Effect on natural gas-fired generating units - February 8 - 13

As outages of natural gas infrastructure facilities began to increase during the week of February 7, natural gas production began to decline. This led to natural gas-fired BES generating unit outages and derates in both SPP and ERCOT. From the start of the Event on February 8 to early Tuesday morning, February 9, SPP experienced unplanned outages and derates of natural gas-fired generating units totaling 450 MW caused by natural gas fuel supply issues. By Friday night, February 12, SPP had 3,200 MW of natural gas-fired generating units outaged or derated due to natural gas fuel supply issues, and by the evening of February 13, with the coldest weather conditions yet to arrive, natural gas-fired generating units outaged or derated due to natural gas fuel supply issues had jumped to 5,000 MW.

Figure 41: Natural Gas-Fired Generating Unit Production, February 8-12, 2021

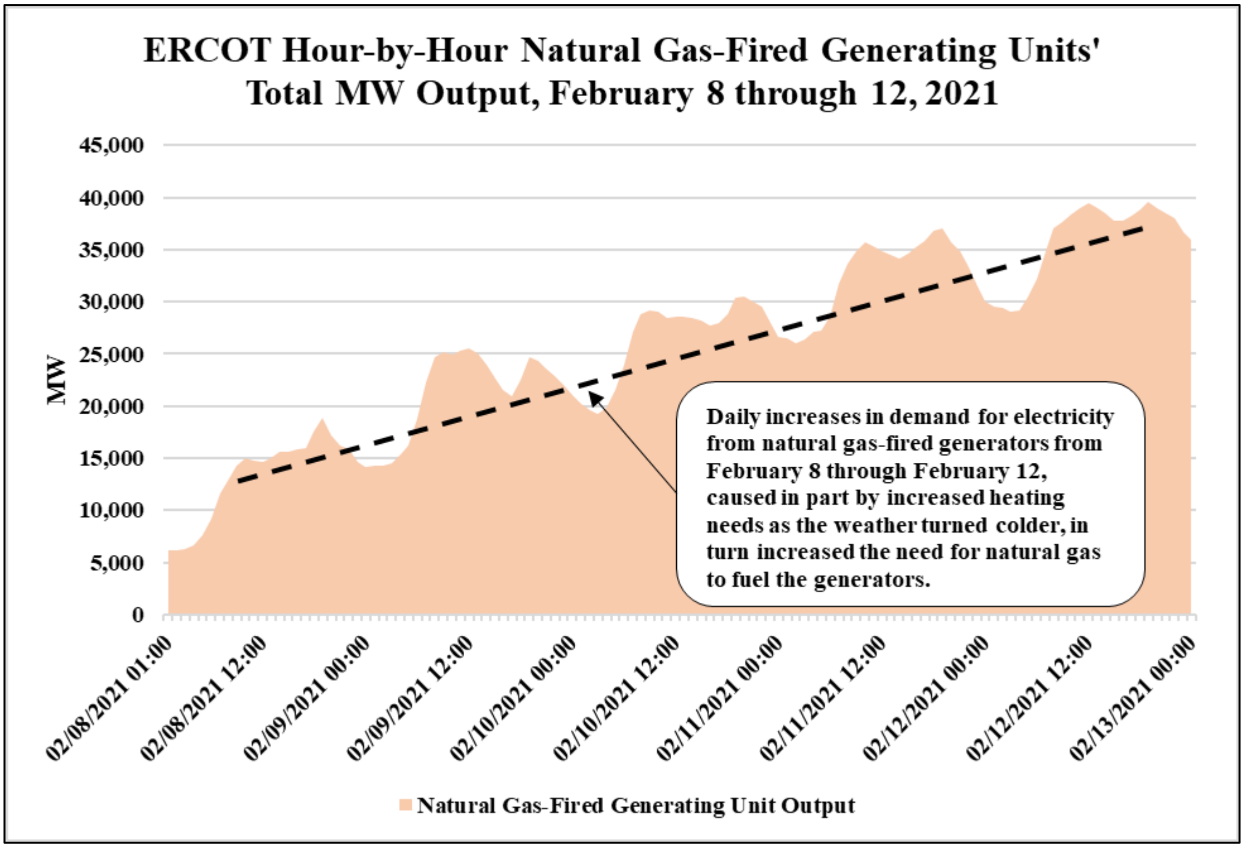
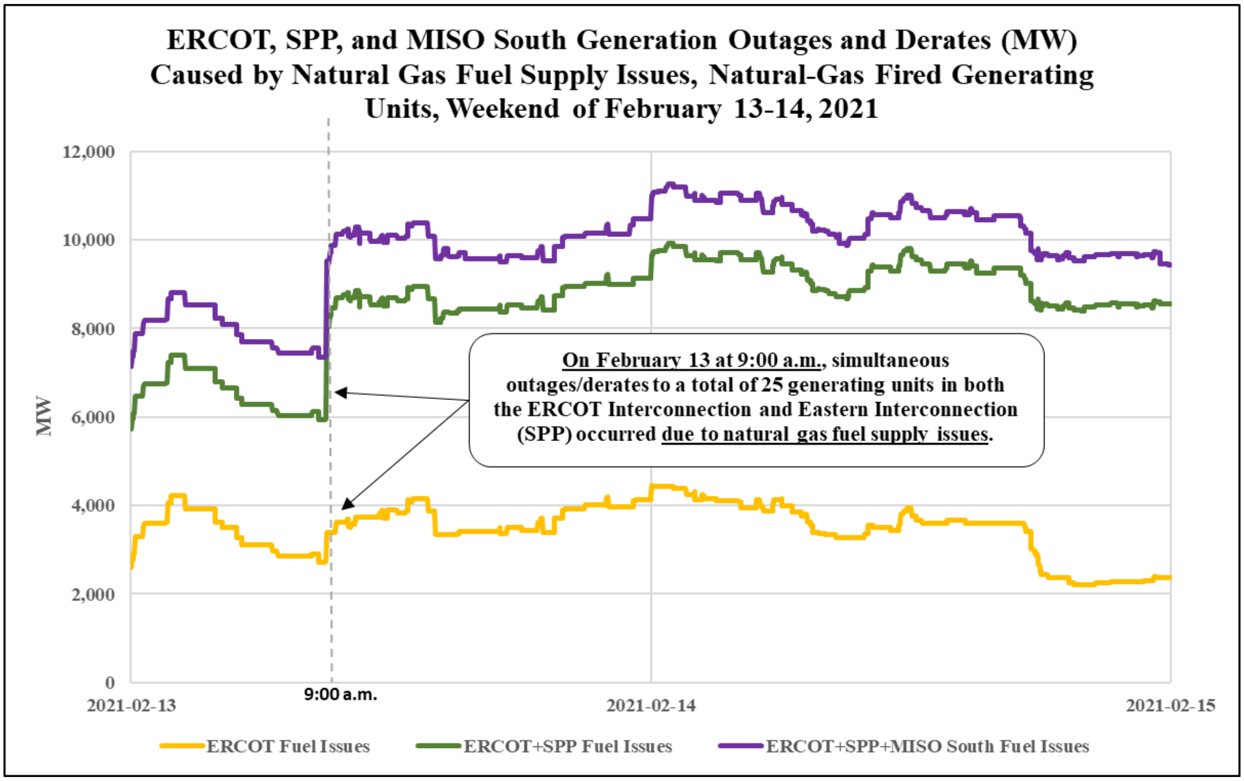


Figure 41, above illustrates the increased need for natural gas to fuel natural gas-fired generating units in ERCOT from February 8 through February 12, before increased demand from natural-gas fired generating units began to exceed available natural gas fuel supply in the Event Area. Outages and derates due to natural gas fuel supply issues began in ERCOT on February 11. By the close of the week on Saturday, February 13, with the coldest weather conditions yet to arrive in the ERCOT footprint, outages and derates of natural gas-fired generating units caused by natural gas fuel supply issues exceeded 4,000 MW. A substantial portion of these outages occurred at 9 a.m. on February 13, when nine natural gas-fired generating units in SPP supplied by Southern Star Central Gas Pipeline experienced fuel-related outages and derates, one GO/GOP in SPP derated 13 of its generating units due to natural gas fuel supply restrictions, and three units in ERCOT were outaged or derated due to a lack of fuel, causing simultaneous outages or derates of 25 natural gas-fired generating units in ERCOT and SPP, as shown on Figure 42, below.[171]

[171] The majority (17) of the 25 generating units had firm pipeline transportation and firm supply for at least some of their contracted volumes. Only nine of those generating units had their supply interrupted by the supplier. These 25 units had a combined nameplate capacity of 3,859 MW and contributed 2,791 MW of generation losses from 9:00-9:10 a.m.

Figure 42: ERCOT, SPP and MISO Generation Outages and Derates Due to Natural Gas Fuel Supply Issues – Weekend of February 13-14, 2021



4. BA/RC Real-Time Actions – February 8 – 13

a. ERCOT

ERCOT BA and RC operators were aware of the cold weather forecast and began issuing notices and advisories as shown in Figure 19 above. When the arctic air and freezing precipitation moved into northern Texas at the start of the week of February 7, ERCOT RC operators began to log reports of generating unit outages and derates and their causes. Beginning February 8, at 7:50 a.m., ERCOT saw its first reports of wind generating unit outages and derates due to turbine blade icing. ERCOT BA operators continued to receive reports of wind generating turbine blade icing around-the-clock for the remainder of the week.

On February 10, ERCOT BA learned that Atmos-Pipeline Texas was having difficulties in delivering natural gas due to the natural gas production declines and would be implementing fuel supply restrictions on February 12. The restrictions then remained in effect throughout the Event, until February 21. As the week progressed, generating unit outages in the ERCOT footprint increased, primarily due to freezing issues and natural gas fuel supply issues described in section B, above. The declining generation capacity, coupled with heating-load-driven energy demands steadily increasing throughout the week (as shown in Figure 27, above), resulted in a declining generation capacity margin to meet the demand, plus a sufficient cushion of "reserve" required above the demand, referred to in ERCOT as Responsive Reserve.[172]

By Friday February 12, even before the coldest weather had reached Texas, ERCOT's system load peaked at 63,997 MW, which was already 97 percent of its all-time historical winter peak load. On February 12 at 12:13 p.m., ERCOT BA notified the PUCT that it may need to declare an EEA during the afternoon, due to limited generation availability and high system load levels. On February 12 at 3:30 p.m. (and lasting until 5:11 pm), ERCOT BA declared a fuel supply emergency that could impact electric power system adequacy or reliability, although ERCOT did not end up declaring an EEA.[173] Cold temperatures and freezing precipitation also led to some transmission facility outages during the week of February 7, although ERCOT quickly returned most transmission facilities to service.

Normally, weekend loads are lower than weekdays; but with colder weather continuing to spread into southern Texas, electricity heating demands increased ERCOT's system load significantly during the morning hours of Saturday, February 13, peaking at 64,132 MW by 11:00 a.m. At 8:43 a.m., with higher-than-normal system loads, additional unplanned generating unit outages that occurred overnight due to natural gas fuel supply issues and wind turbine outages caused by blade icing, ERCOT's Physical Responsive Capability dropped below 3,000 MW. ERCOT issued a system Advisory, meaning that GOPs and TOPs may need to take actions in anticipation of an EEA.[174] At 8:49 a.m., ERCOT operators issued an Emergency Notice for the extreme cold weather event impacting the ERCOT footprint. ERCOT cancelled the advisory when its system load decreased somewhat on Saturday afternoon, returning its Physical Responsive Capability above 3,000 MW and avoiding the need to declare an EEA.

b. SPP

As shown earlier in Figure 19, SPP BA system operators also issued an Operating Condition Notice based on the extreme cold weather forecast for its footprint. On February 7 (two days earlier than in ERCOT), SPP BA began to receive critical notices from the interstate Gulf South gas pipeline,

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[172] ERCOT Responsive Reserve is an ancillary service that provides operating reserves intended to arrest frequency decay within the first few seconds of a significant frequency deviation using Primary Frequency Response and interruptible load; after the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal; provide energy or continued load interruption during the implementation of the EEA; and provide backup regulation. *See* ERCOT Nodal Operating Guide http://www.ercot.com/mktrules/guides/noperating.

[173] ERCOT OE-417 of February 12 at 3:30 p.m. stated, "[g]as fuel supplies are limited to generators impacting generation availability due to the extreme cold weather impacting the ERCOT region resulting in gas company curtailments."

[174] Based on its emergency operations protocols, ERCOT issues an Advisory when its "Physical Responsive Capability" or PRC drops below 3,000 MW. ERCOT system operators issued an Emergency Notice for extreme cold weather system beginning to have an adverse impact on its footprint. ERCOT instructed QSEs to make resources available that can be returned to service and keep COPs and high sustained limits for generating units updated, keep ERCOT informed of known or anticipated fuel restrictions, and notify ERCOT of any changes or conditions that could affect system reliability.

warning that limited input into the pipelines from natural gas production facilities could hinder deliveries of natural gas to natural gas-fired generating units in SPP's footprint. At least two interstate and two intrastate pipelines with facilities in the South Central region issued system-wide notices on February 6 of upcoming winter weather lasting for the next week or two. On February 9, SPP began regular communications[175] with Southern Star, one of the largest interstate natural gas pipelines that delivers to natural gas-fired generating units in its footprint. SPP and Southern Star staff continued discussions throughout the Event to coordinate gas issues and pipeline reliability as part of a proactive resource commitment approach. SPP did not have a similar relationship with other natural gas pipelines serving generating units within its footprint. By the end of February 13, SPP already had over 9,700 MW of natural-gas fired generating units unavailable, before the coldest temperatures arrived. But in addition to natural gas fuel supply issues, SPP began to lose wind turbines to blade icing—beginning February 8, at approximately 3:15 a.m., which quickly rose to 123 outages and 10,700 MW of wind generation capacity unavailable by February 9.

On February 11, SPP began committing generating resources using its multiday reliability assessment process, expecting more outages from natural gas fuel supply issues due to its close coordination with Southern Star. Instead of committing generating units one day ahead, as is standard practice, SPP began sending them instructions several days in advance that they would be responsible for serving load for the period Saturday, February 13 through Tuesday, February 16.

As the week of February 7 progressed, SPP's electricity demand or load steadily increased, driven by electric heating loads (as shown in Figure 27, above, and similar to ERCOT). Lower system load on Saturday February 13, and 2,000 MW of wind generation that had returned to service from blade icing outages, helped to offset a portion of the 4,000 MW of increased outages and derates of natural gas-fired generating units due to natural gas fuel supply issues. In summary, SPP had sufficient generation capacity to meet load in its footprint during the week of February 7 and thus did not need to implement emergency measures.

c. MISO / MISO South

Because MISO South began to experience the colder weather later than SPP and ERCOT, it did not experience any significant generation outages or derates during the week of February 7. However, the MISO BA operators knew that the severe cold weather conditions were forecast to reach deep into the South Central U.S. early in the week of February 14. See Figure 19. On February 8, SPP and MISO began management-level discussions about the forecast severe cold weather conditions and natural gas fuel restrictions expected. Discussions continued during the remainder of the week to ensure coordination as the weather worsened.

MISO transmission grid conditions during week of February 7. Overall, MISO's transmission system was normal operation during the week of February 7. Figure 43, below, shows the total actual import power which flowed on SPP's AC tie-lines (most of which are with MISO, listed in Figure 9, above) from February 11 through 13.

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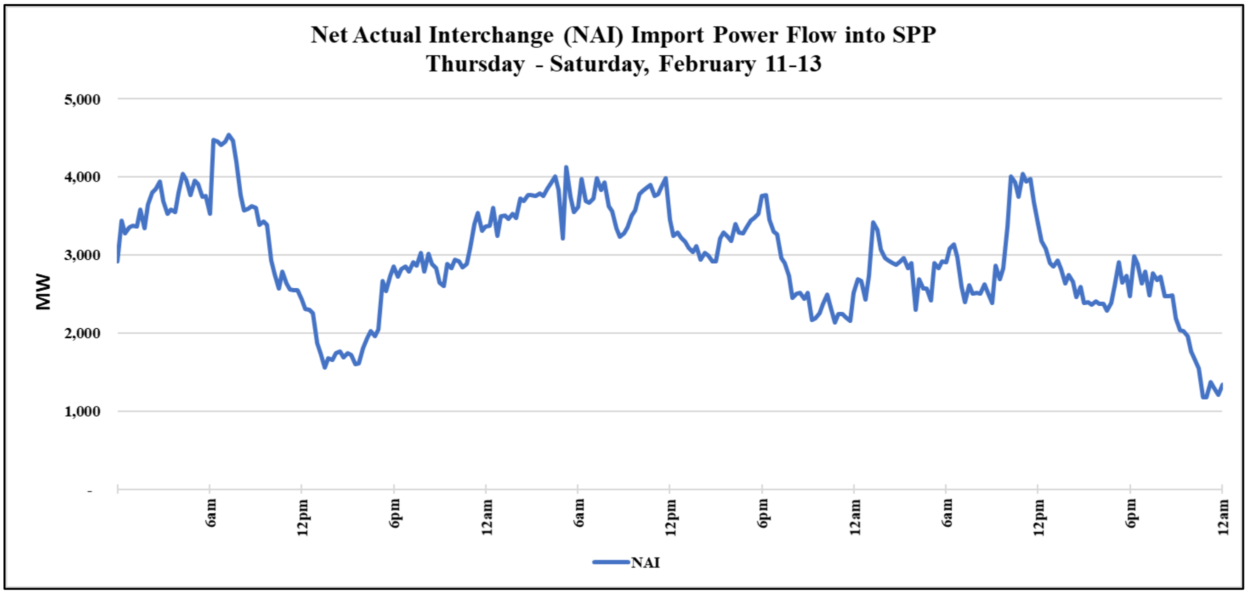
[175] This communication was part of an ongoing relationship between the two entities, including participation by SPP staff in the Southern Star users' group.

Figure 43: Transmission Import Power Flow into SPP, February 11-13



Even though SPP market imports reached as high as 4,600 MW on February 11 and 4,000 MW on February 13, MISO's transmission system was much less constrained during the week of February 7 than the following week, and normal (non-emergency) operations measures sufficed to manage transmission system reliability.[176] On February 11, as the expectation for the duration of extreme cold expanded, MISO extended its Cold Weather Alert through the end of the day February 16, and alerted operators to expect to be contacted about fuel restrictions. Even as MISO South's load began to increase with lower temperatures on February 11 and 12, it still had sufficient reserves and had only reached 83 percent of its all-time peak load.

> Power transfers (e.g., importing power from other Balancing Authorities) can be used to provide generation supply and reserves to areas where there may be generation shortfalls, but in addition to the specific transmission ratings on the lines over which the power is being transferred, there are other limitations to the amount of power that can be reliably transferred on the power grid. The importing BA (for example, SPP) simultaneously needs its remaining online generation to serve load (to avoid need for load shed) and to reduce transmission congestion via redispatch to accommodate import power transfers. Any remaining online generation used for one purpose is not available for the other. Attempting to transfer more power than

[176] SPP imports would similarly vary from 4,000 to nearly 6,500 MW on the morning of February 15; but on that day, SPP and MISO would be facing one of the coldest days and peak load periods of the Event, and generating unit outages would have greatly escalated in both footprints. Under those very different conditions, SPP import levels relatively similar to the week of February 7 would now need to be curtailed to alleviate transmission system emergency conditions in MISO. *See* Figure 79.

> can be supported by redispatch can create wide-area constrained grid conditions. When the grid is constrained on a wide area, the danger of violating SOLs or IROLs leads to constant contingency monitoring and redispatch or even firm load shed, as in the Event, for a transmission emergency. While east-to-west transfers played a critical role in helping MISO and SPP largely compensate for the generation outages during the Event, there eventually comes a limit to the amount of power that can be reliably transferred.[177]

As Sunday, February 14, approached, ERCOT, SPP and MISO BAs were fully aware of colder weather approaching. ERCOT and SPP had already weathered rising load and generating unit outages from natural gas fuel supply issues and blade icing, and all three BAs had ended the week of February 7 without taking emergency actions.

Everything was about to change in the coming week, in which the weather would worsen, and all three BAs would simultaneously face emergency conditions.

C. February 14 - 19: Extreme Below-Normal Cold Weather Conditions Lead to Widespread Generation Outages, Forcing Grid Operators to Make Hard Decisions

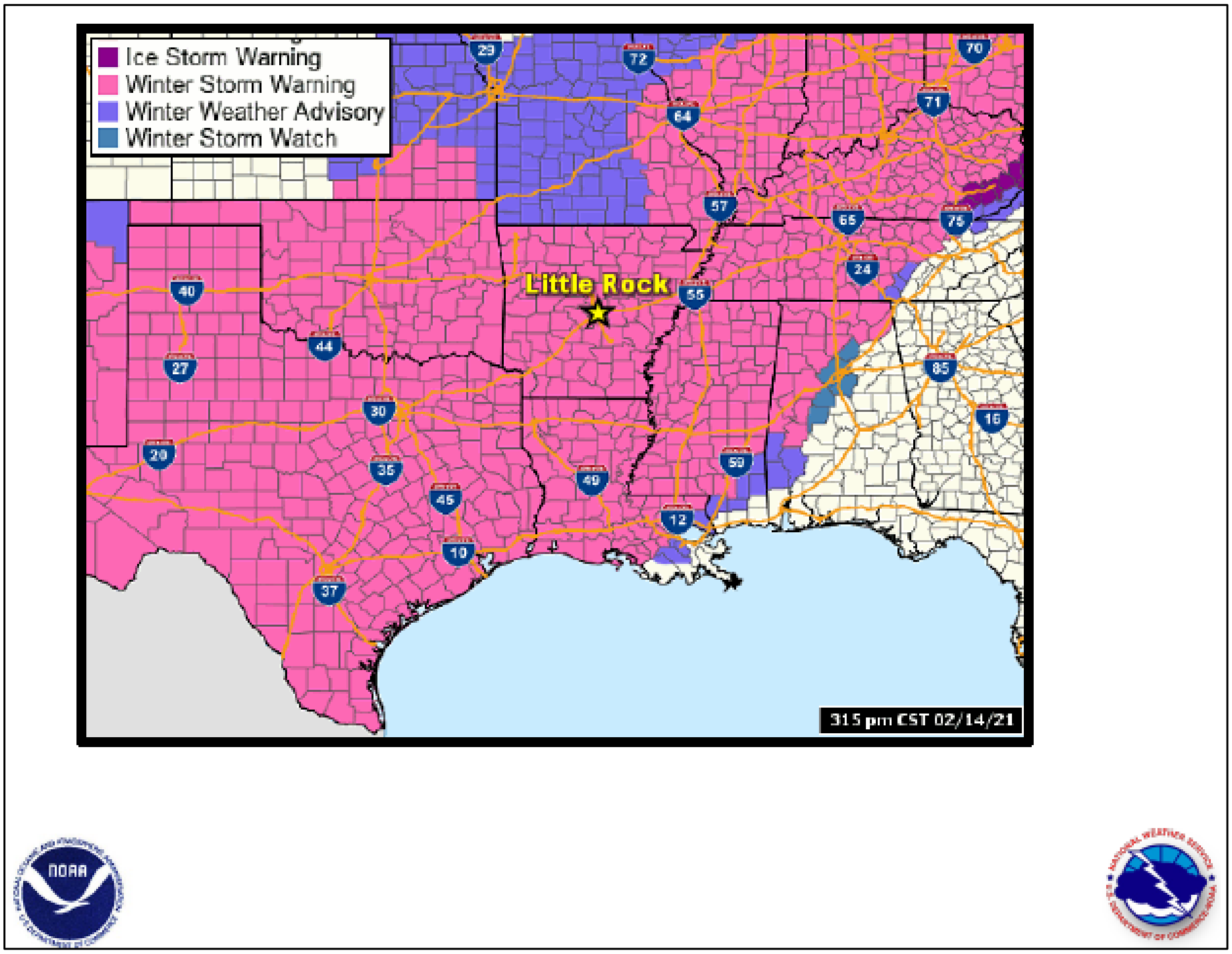
- *The Coldest Temperatures and Freezing Precipitation Begin*
- *Unplanned Generation Outages Increase*
- *Grid Operators Forced to Make Hard Decisions*

1. Overview of Worsening Weather Conditions

Beginning the weekend of February 13 and 14, and extending through Thursday, February 18, the Event Area experienced a wave of extreme cold temperatures, accompanied by snow, freezing rain and wind conditions. Precipitation began on February 13, with heavy snow occurring in Oklahoma and Arkansas, and rounds of snow, sleet and freezing rain continuing in parts of Texas, Louisiana, and Mississippi as late as Thursday, February 18. Figure 44 (below) shows the extensive area that was under a winter storm warning on February 14, while Figure 45 illustrates how low temperatures during the Event departed from normal lows on February 15.

[177] *See* 2018 Report at pages 93 – 94.

Figure 44: NOAA National Weather Service – Winter Storm Warning, February 14, 2021[178]



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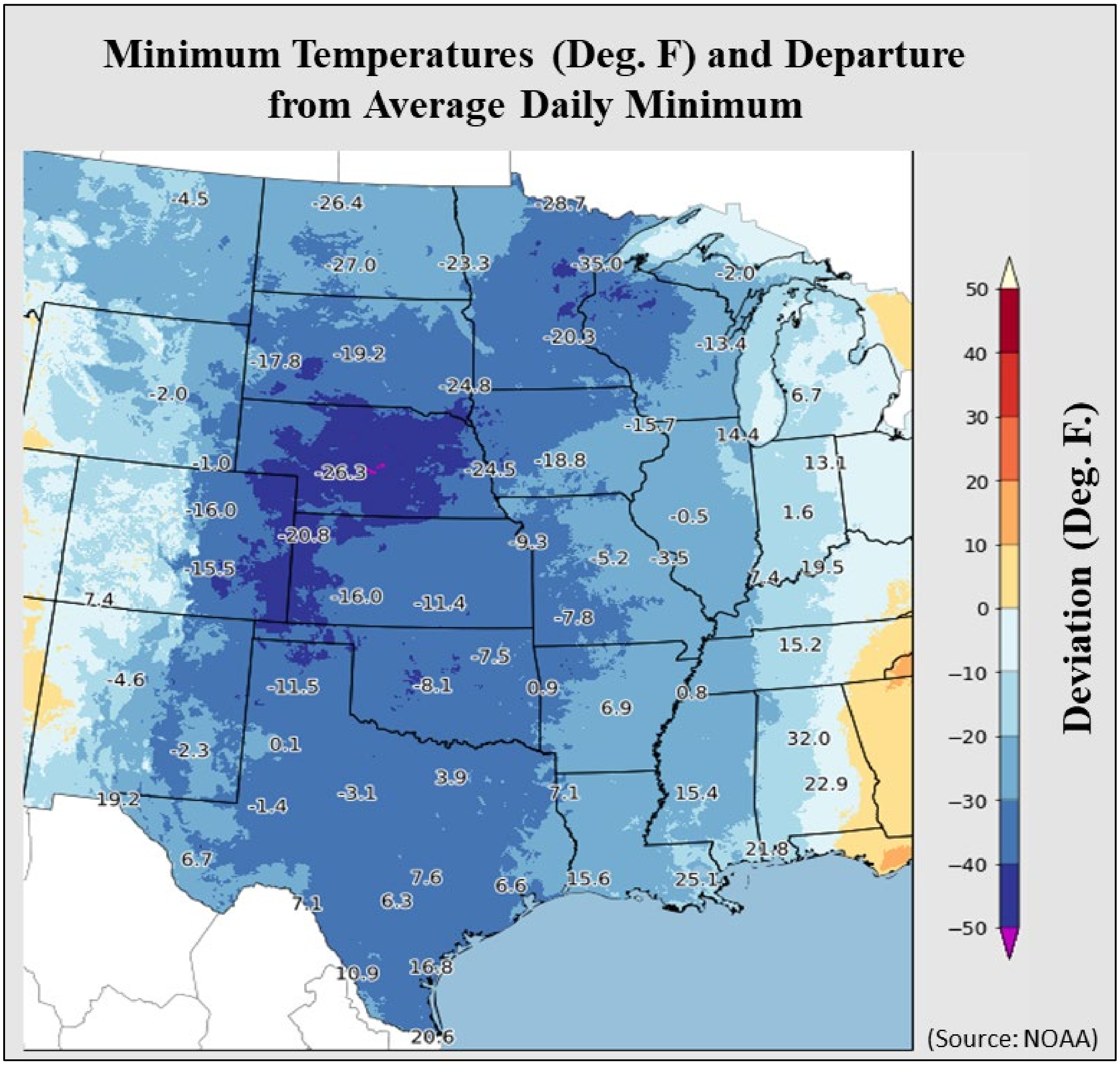
[178] A watch is used when the risk of a hazardous weather or hydrologic event has increased significantly, but its occurrence, location, and/or timing is still uncertain. It is intended to provide enough lead time so that those who need to set their plans in motion can do so. An advisory highlights special weather conditions that are less serious than a warning. It is used for events that may cause significant inconvenience, and if caution is not exercised, could lead to situations that may threaten life and/or property. A warning is issued when a hazardous weather or hydrologic event is occurring, is imminent, or has a very high probability of occurring. A warning is used for conditions posing a threat to life or property.

Figure 45: February 15, 2021 Minimum Temperatures and Departures from Average Daily Minimum



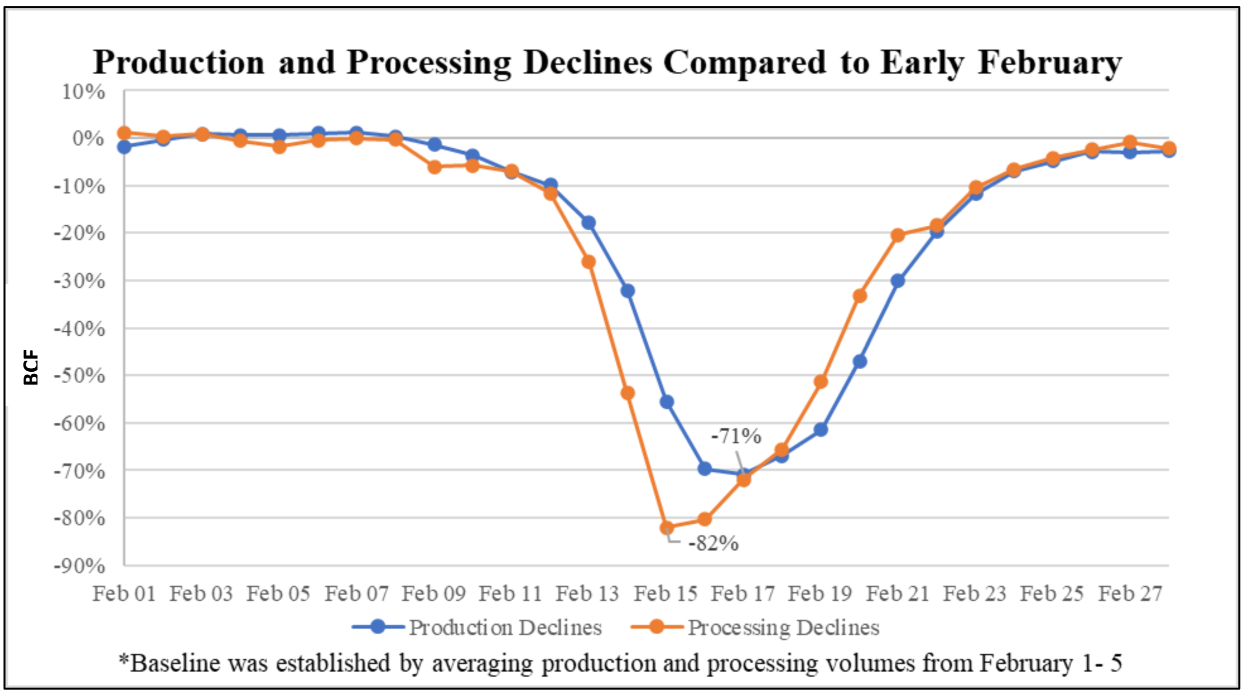
2. Effects on Natural Gas Infrastructure

a. Additional Natural Gas Production Declines in Texas and South Central U.S.

Natural gas infrastructure including wellhead, gathering, and processing facilities all suffered some degree of unplanned outages primarily due to the cold weather conditions that began on approximately February 7, resulting in a decline in natural gas supply. By February 14, natural gas wellhead and gathering facility production declined by over 30 percent, while processing declined by over 50 percent, as compared to February 1 through 5 production and processing levels, respectively. By February 15, processing had declined by over 80 percent and by February 17, production had declined by 71 percent. (See Figure 46 below).

On February 14, 88.4 percent of the volumetric contribution to the decline in natural gas production was related to the extreme cold weather. Slightly more than half of the production decline (52.2 percent) resulted from freezing issues or shut-ins to prevent freezing, while 18.1 percent resulted from loss of power (caused by a combination of ERCOT-wide firm load shed and local weather-related distribution line outages)[179] and 18.2 percent resulted from a combination of issues (for example, freezing and loss of power) (see Figure 47 below). Processing losses, analyzed by the day of maximum losses in each basin, were largely caused by reduced gas supply, as one would expect (see Figure 51). For example, the Fort Worth and Gulf Coast Basins on February 17 each had 100 percent of outages caused by reduced gas supply, the Anadarko Basin on February 16 had 81 percent, and the Permian and Eagle Ford on the February 16 and 17, respectively, each had over 50 percent of outages caused by reduced gas supply. In some basins, power outages played a larger role, with 77 percent of Haynesville Basin outages on February 19 reported to be caused by power outages/curtailments.

Figure 46: Production and Processing Declines Compared to Early February



[179] The February 14 gas day covers the 24-hour period beginning at 9 a.m. Central Prevailing Time on February 14 and ending at 9 a.m. on February 15. Between midnight February 14 and 9 a.m. February 15, ERCOT and MISO both shed firm load, and the producers did not provide data with sufficient granularity to allocate gas production data between the calendar days of February 14 and 15. *See* ERCOT Frequency Decline and Recovery: February 15, Approximately Midnight to 2 a.m., section III.C.4.(b)(i) for more information on ERCOT's orders for firm load shed, and III.C.4.(c)(i) and (iv) for more information on MISO's orders for firm load shed.

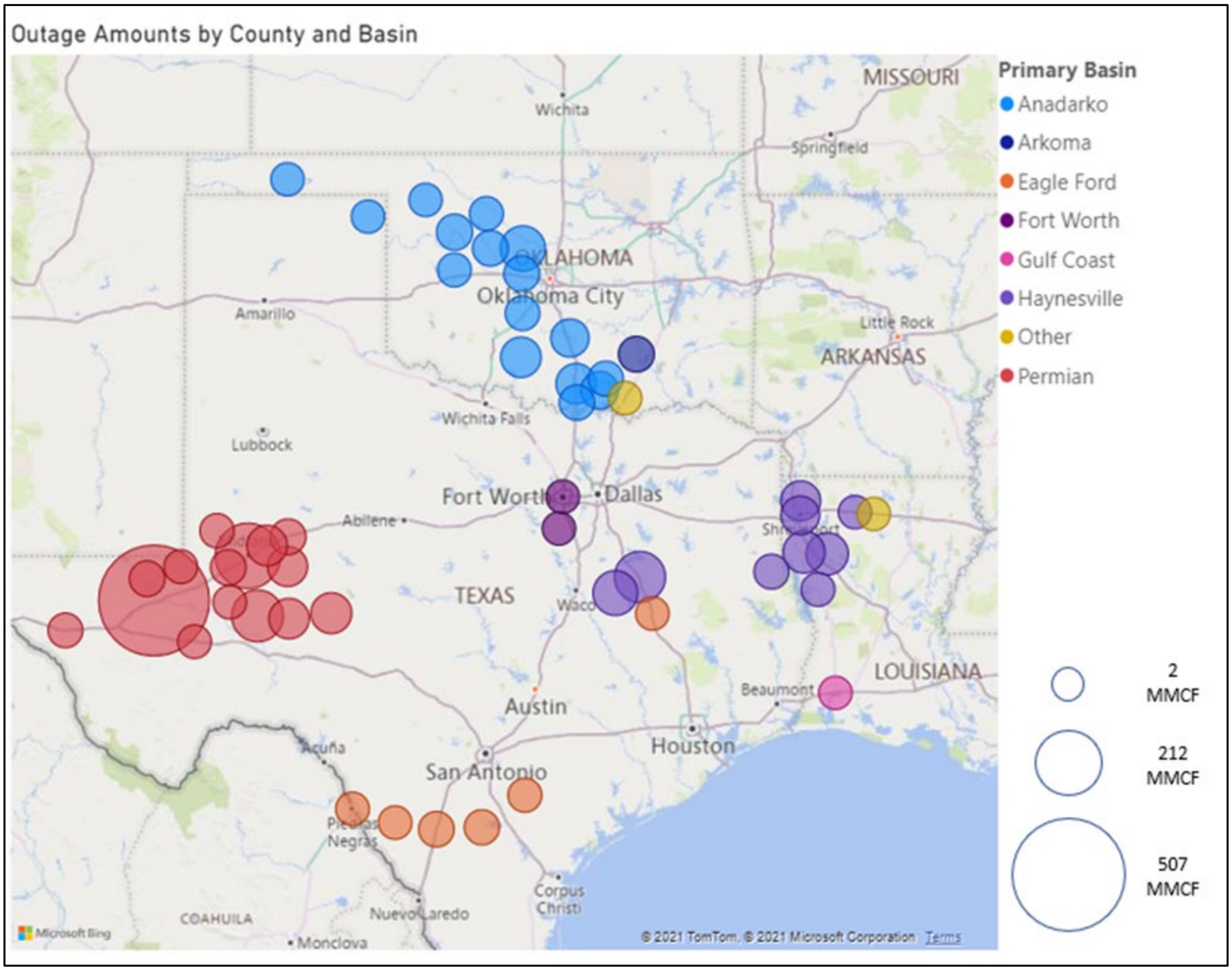
Figure 47: Volumetric Contribution of Production Outage Causes on February 14, 2021, 9:00 a.m. to February 15, 9:00 a.m. Gas Day (inclusive of ERCOT Load Shed)

Production Event Causes on February 14th (Gas Day, inclusive of a portion of ERCOT Load Shed Event)

88.4%

	Natural Gas Infrastructure Condition	Facility Event Causes
Freezing Temperature and Weather Conditions (52.1% of production disruptions)	**Facility Shut-ins to Prevent Imminent Freezing Issues**	**33.6%**
	Freezing Issues - Midstream	**2.2%**
	Freezing Issues at Well and Gathering Facilities	**15.6%**
	Freezing Issues on Roads/Access to Well and Gathering Facilities	**0.8%**
Loss of Power Supply (18.1% of production disruptions)	**Midstream - Loss of Power Supply**	**10.0%**
	Well/Gathering Facilities- Loss of Power Supply	**8.1%**
Multiple Issues (18.2% of production disruptions)	**Multiple Issues (combination of two or more of above issues)**	**18.2%**
Other Issues, Unrelated Issues (11.6% of production disruptions)	**Midstream - Line Pressure**	**1.6%**
	Midstream - Other	**0.0%**
	Well and Gathering Facility Issues - Not Applicable to Event	**10.0%**
Total		**100.0%**

Figure 48a: Natural Gas Production Volumetric Outages by Primary Basin, February 14[180]



180 All outage events smaller than 1 MMCF are excluded from figure.

Figure 48b: Natural Gas Production Volumetric Outages by Primary Cause, February 14

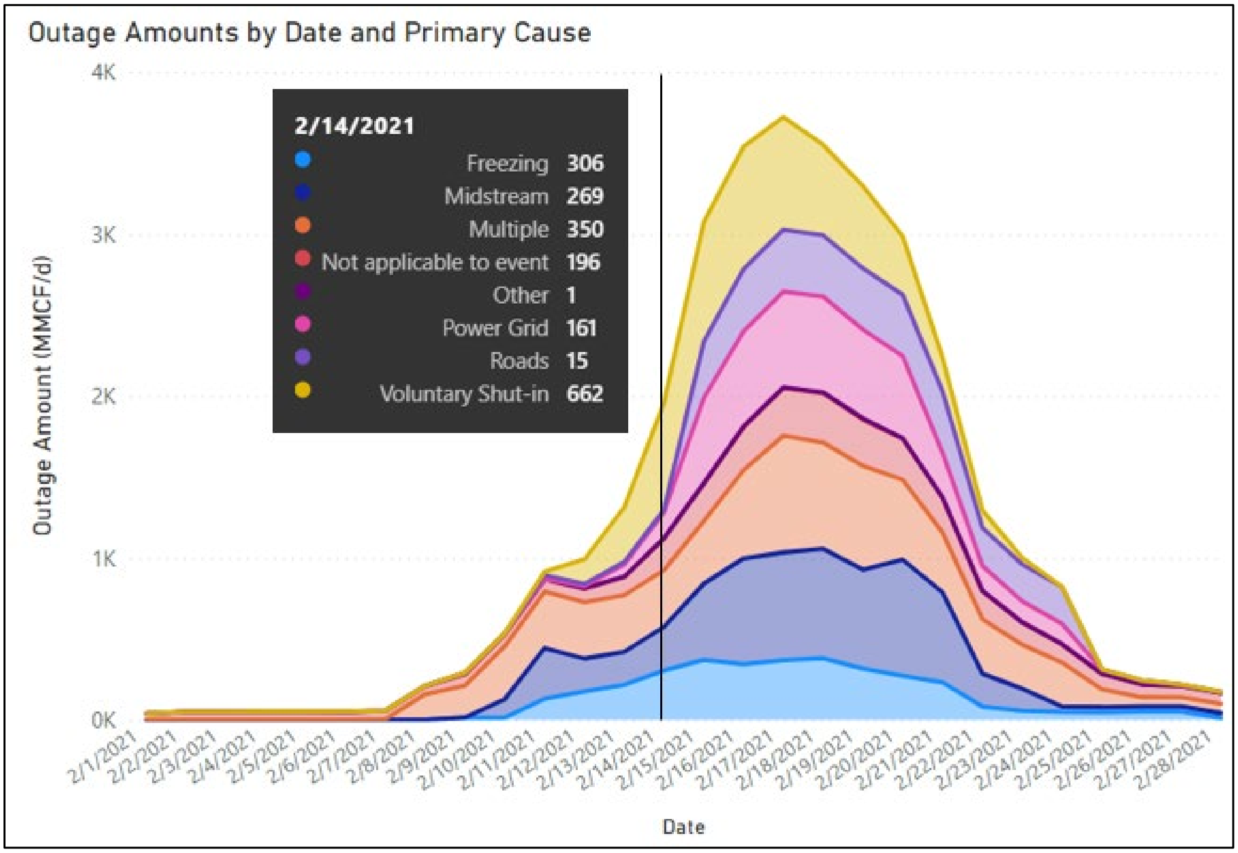
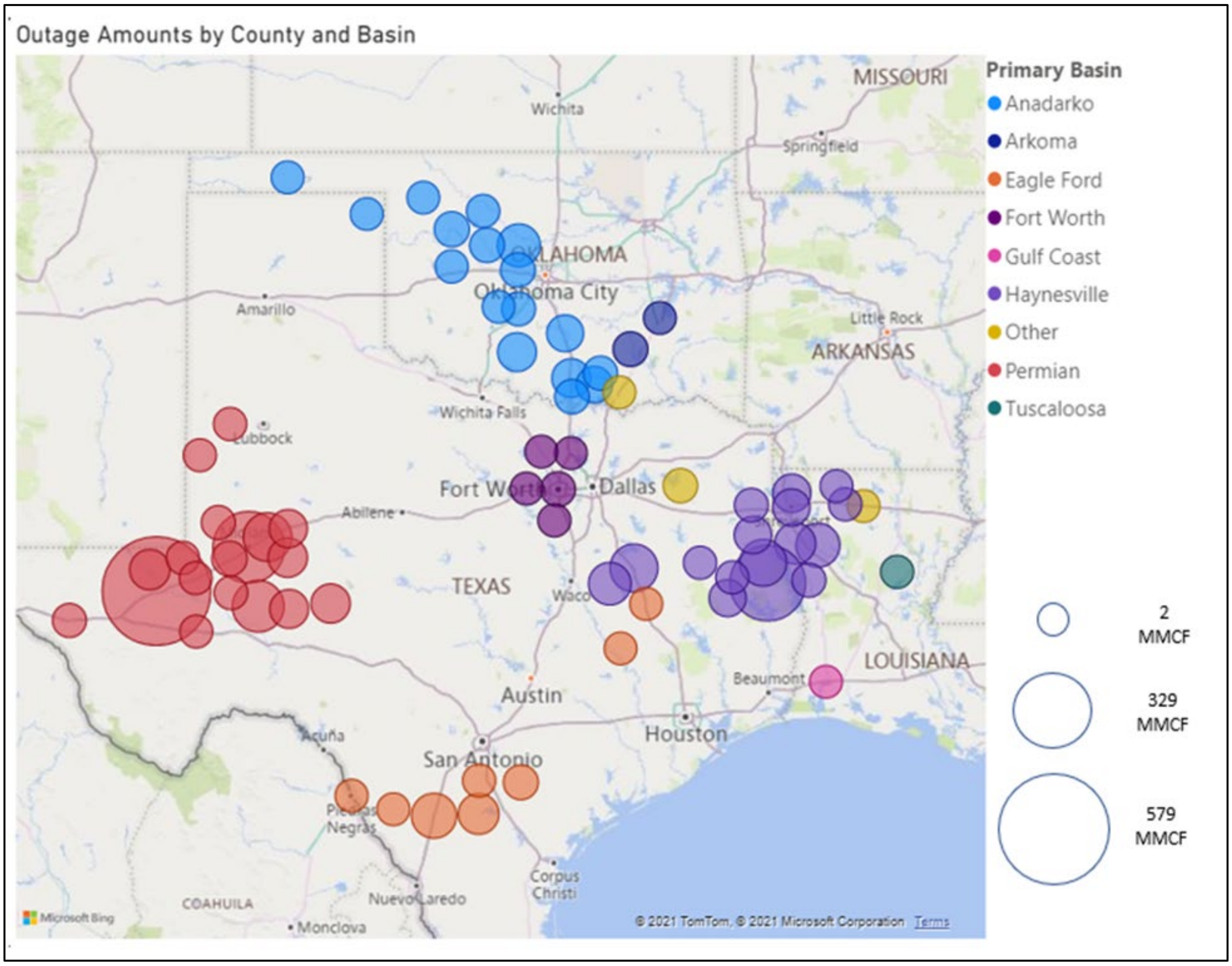


Figure 49a: Natural Gas Production Volumetric Outages by Primary Basin, February 15[181]



[181] All outage events smaller than 1 MMCF are excluded from figure.

Figure 49b: Natural Gas Production Volumetric Outages by Primary Cause, February 15

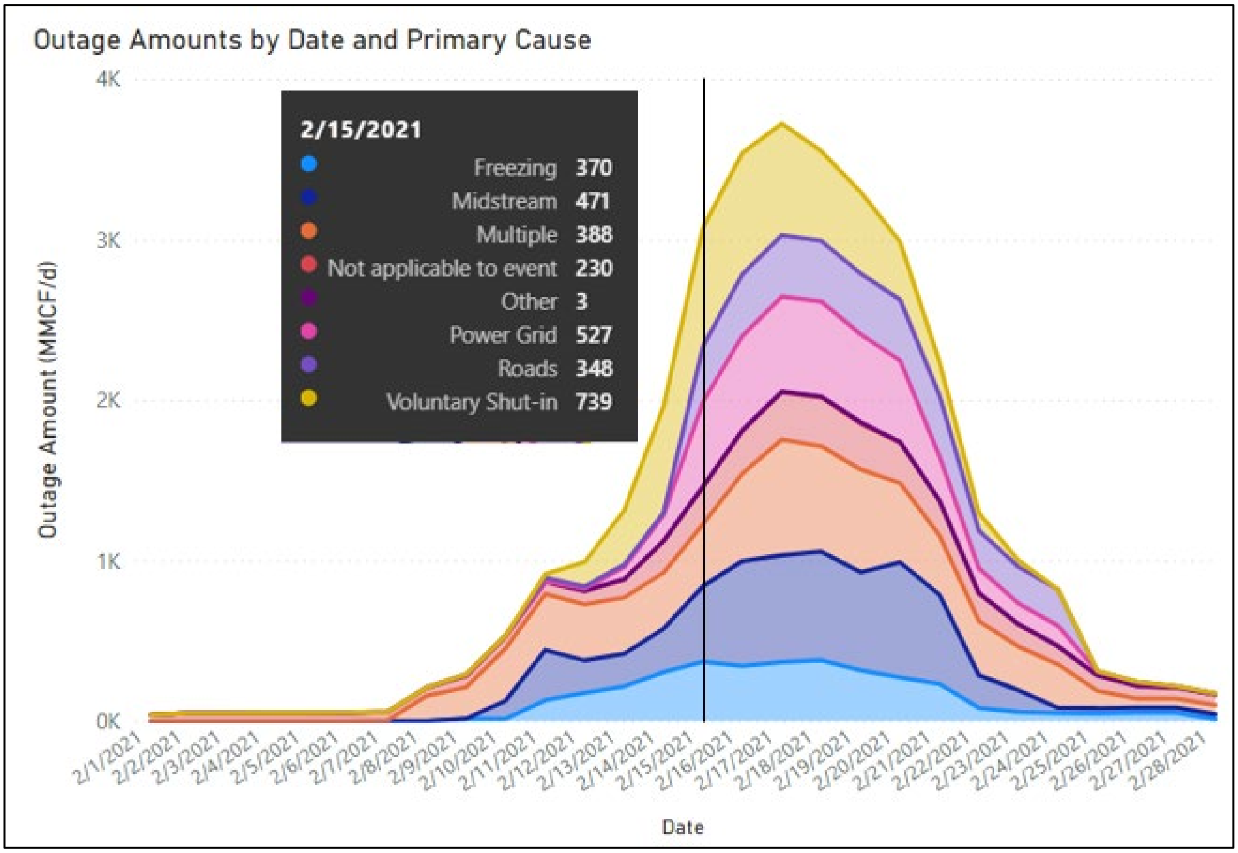
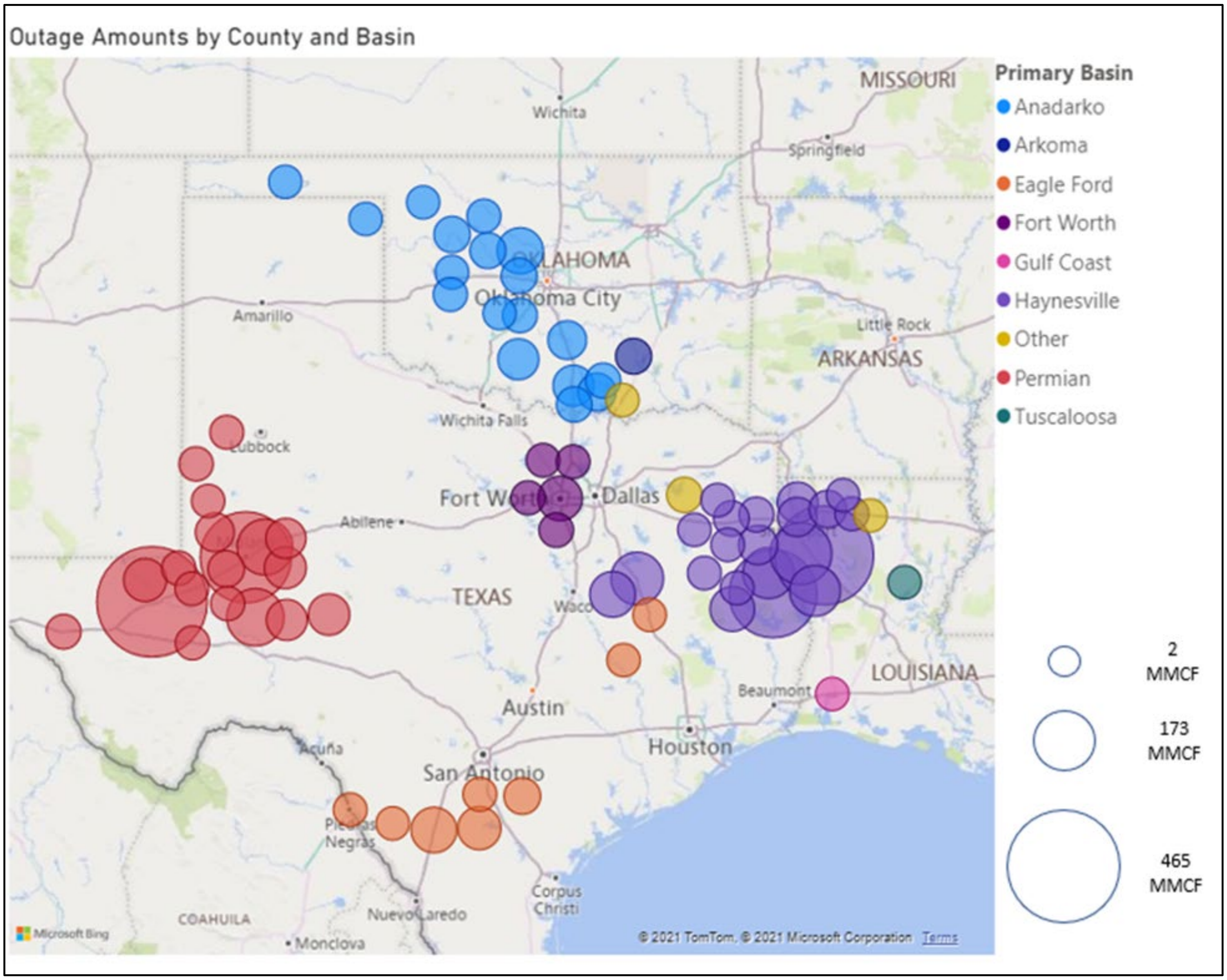


Figure 50a: Natural Gas Production Volumetric Outages by Primary Basin, February 17[182]



[182] All outage events smaller than 1 MMCF are excluded from figure.

Figure 50b: Natural Gas Production Volumetric Outages by Primary Cause, February 17

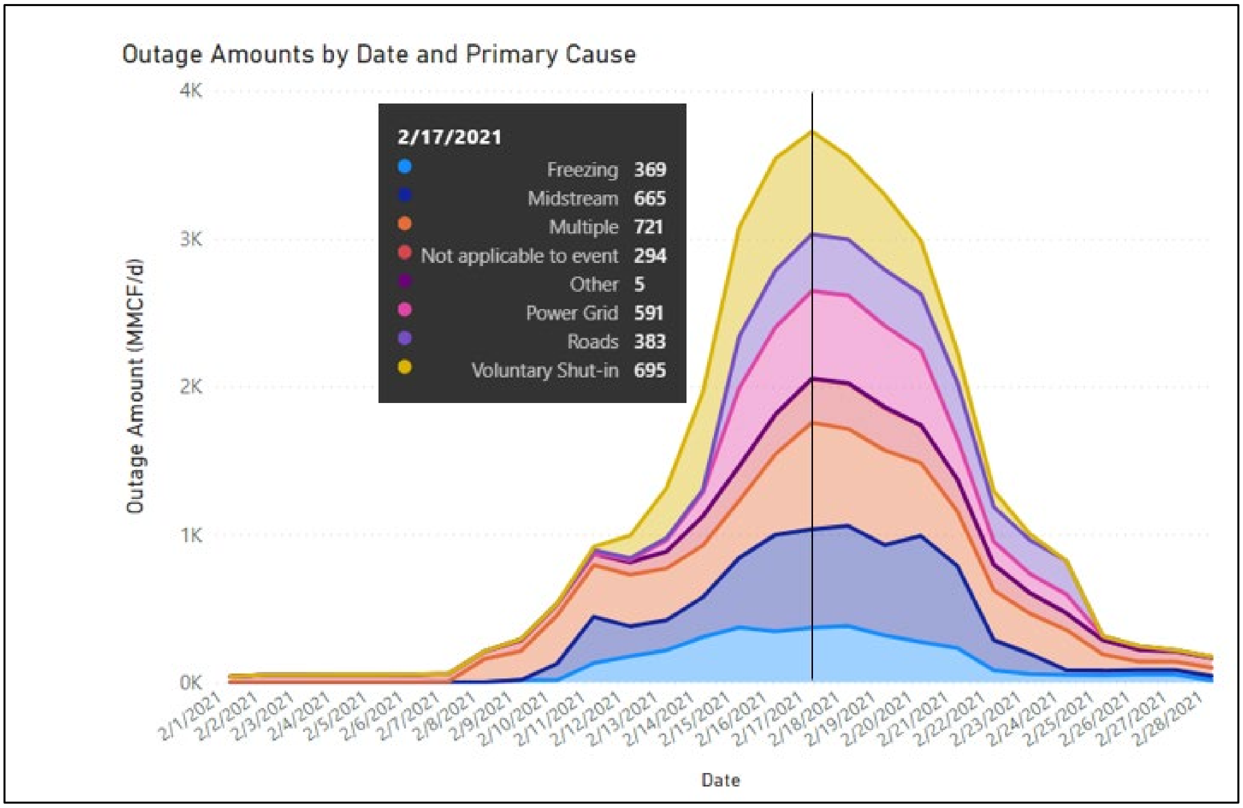


Figure 51: Volumetric Contribution Comparison of Sampled Processing Outages by Basin, February 16-19, 2021

BASIN	MAXIMUM DAILY PRODUCTION OUTAGE (Bcf)	MAXIMUM DAILY PROCESSING OUTAGE (Bcf)	CAUSES
Anadarko (Feb 16th)	1.23 Bcf	0.35 Bcf	81% Reduced Gas Supply, 6% Power Outages/Curtailments, 13% Mechanical failures not related to weather
Permian (Feb 16th)	2.01 Bcf	1.04 Bcf	58% Reduced Gas Supply, 25% Power Outages/Curtailments, 17% Mechanical failures related to weather
Fort Worth (Feb 17th)	0.6 Bcf	0.02 Bcf	100% Reduced Gas Supply
Eagle Ford (Feb 17th)	0.66 Bcf	0.09 Bcf	50% Reduced Gas Supply, 50% Power Outages/Curtailments
Gulf Coast (Feb 17th)	0.02 Bcf	0.38 Bcf	100% Reduced Gas Supply
Haynesville (Feb 19th)	2.09 Bcf	0.38 MMcf	25% Reduced Gas Supply, 75% Power Outages/Curtailments

Utility Curtailment Programs and Priority of Service in Emergencies. As compared to natural gas pipeline companies, which typically adhere to strict definitions of firm and interruptible or non-firm transportation, some states have outlined natural gas curtailment programs or priorities of service for utility customers during emergencies that prioritize human needs. These priorities of service can align with, or supersede, contractual terms and conditions. For example, the Texas RRC has rules that mandate that in emergencies, natural gas utilities provide the highest priority deliveries to residences, hospitals, schools, churches, and other human needs customers, small industrials and regular commercial loads.[183] Residential home heating load normally has firm pipeline transportation provided by its local distribution company, which also provides it with the highest level of contractual priority. In emergencies, industrial customers, including natural gas-fired generating units, would normally be interrupted or curtailed before residential and commercial customers, regardless of contractual priority. During the Event, the RRC issued an emergency order, effective February 12, which elevated "[d]eliveries of gas to electric generation facilities which serve human needs customers" as second in priority behind "deliveries of gas by natural gas utilities to residences, hospitals, schools, churches and other human needs customers, and deliveries to Local Distribution Companies which serve human needs customers."[184] This order had the effect of prioritizing deliveries of gas to generating units even if they did not have firm pipeline transportation contracts.

Natural Gas Usage by End-User Type for February 2021

Natural gas use by residential and commercial end-users:

- Home Heating/Residential Natural Gas Demand: due to the extreme cold weather, the demand for natural gas for home heating increased significantly. In February 2021, the residential sector consumption in Texas reached a monthly record high of 1.8 Bcf/d, 53 percent higher than February 2020 levels and 64 percent higher than the five-year average.[185]
- Commercial Natural Gas Demand: Commercial sector consumption of natural gas in Texas also increased in February, reaching 0.92 Bcf/d, the highest level since January 2018.[186]

Natural gas use by large industrial users: In February, industrial sector natural gas consumption in Texas fell to 4.1 Bcf/d, or 23 percent lower than February 2020 levels, the largest monthly decline on record, caused by the direct effects of the extreme cold weather, including power outages and equipment failure, and indirect effects, such as supply shortages (including natural gas liquids as raw materials) and extreme prices.[187]

Natural gas use by natural gas –fired generating units: Across the entire month of February, consumers of gas for electric power, which includes natural gas-fired generating units, increased by 4.6 percent over January 2021 use. The increased

[183] *See* https://www.rrc.texas.gov/gas-services/curtailment-plan.
[184] Railroad Commission of Texas, *Emergency Order* (2021), https://rrc.texas.gov/media/cw3ewubr/emergency-order-021221-final-signed.pdf.
[185] Mike Kopalek & Emily Geary, *February 2021 weather triggers largest monthly decline in U.S. natural gas production*, Today In Energy (May 10, 2021) https://www.eia.gov/todayinenergy/detail.php?id=47896
[186] *Id.*
[187] *Id.*

consumption occurred on days in February where natural gas supply *was* available to meet the increased demand of the online natural gas-fired generating units to generate more electricity. Figure 52 below shows the changes in *monthly volume* consumptions of natural gas for end-users from January to February 2021 for Texas, Oklahoma, and Louisiana, and Figure 53, below shows natural gas demand changes from November 2020 – February 2021.

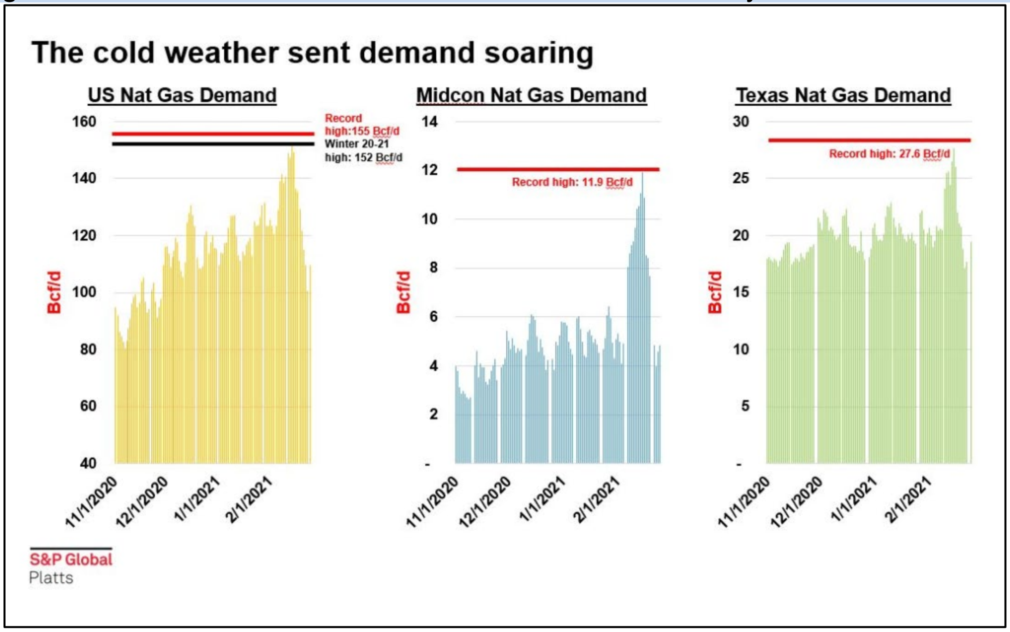
Figure 52: Natural Gas Consumption by End Use, January – February, 2021[188]

Natural Gas Consumption by End Use			
			Percent
	January 2021	February 2021	Change
	(Bcf)	(Bcf)	
Residential - LA	6.9	7.4	7.3%
Residential - OK	13.0	13.9	7.0%
Residential - TX	39.0	50.6	29.9%
Commercial - LA	3.6	3.9	9.1%
Commercial - OK	7.5	8.2	9.4%
Commercial - TX	24.5	25.7	4.9%
Industrial - LA	101.9	83.7	-17.9%
Industrial - OK	20.3	13.8	-32.2%
Industrial - TX	176.7	116.1	-34.3%
Electric Power - LA	20.9	22.6	8.0%
Electric Power - OK	21.4	21.7	1.4%
Electric Power - TX	119.4	124.9	4.6%
(Source: EIA)			

The volume of natural gas consumed by natural gas-fired generating units increased on some days in February 2021, which contributed to the overall increased monthly consumption by electric power as compared to January, as shown in Figure 52, above.

188 *See* U.S. Energy Info. Adm., *Natural Gas Consumption by End Use*, data1 (2021), https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_STX_M.htm.

Figure 53: Natural Gas Demand November 2020 – February 2021



b. Imports of Natural Gas from Other Regions[189]

Natural gas pipelines provided operational flexibility and used reversible flows to import from areas with less demand where possible. The Midcontinent and Texas regions, traditionally suppliers of natural gas to neighboring states, continued to export gas but also imported gas from nearby regions to meet their peak demand. On balance during the Event, the Midcontinent region became a net importer of natural gas on high demand days and Texas saw drastic reductions of exports, as shown in Figure 54 below. In the Midcontinent, exports to northeast Texas experienced a significant decline, by around 1 Bcf/d during the peak days of February 15 and 16. Similarly, Texas reduced its gas exports to nearby states during the storm. The Texas portion of the Permian basin in particular experienced a significant decline in exports to the southwest region by around 0.5 to 0.6 Bcf/d from early February levels on February 15 and 16. South Texas gas flows to serve LNG export markets and Mexico declined by around 2 Bcf/d on February 16.

During the peak of the Event on February 15 and 16, Midcontinent and Texas temperatures tumbled more than 40 degrees below normal, with Midcontinent dipping below zero degrees. As a result, natural gas demand in the Midcontinent hit a new single-day high of 11.9 Bcf/d on February 15, and Texas hit a record of 27.6 Bcf/d on the same day. Figures 54-56 illustrate the change in

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[189] Information in this section sourced from Luke Jackson, *What Caused Midcon/Texas Natural Gas Price Spikes and What are the Implications for US Summer 2021 Balances?* (Feb. 25, 2021, 4:42 PM), S&P Global Platts, https://benport.bentekenergy.com/spotlight/2021/02/what-caused-midcontexas-natural-gas-price-spikes-and-what-are-the-implications-for-us-summer-2021-balances/. Graphics reprinted with permission.

pipeline flows to meet increased natural gas demands in South Central U.S. and Texas during February 2021.

Figure 54: South Central U.S. Natural Gas Inflows and Outflows, February 1 – 20, 2021

Texas Natural Gas Inflows/Outflows Deltas

The tables show natural gas pipeline flow changes between the peak of the storm (Feb. 17-20) vs. pre-storm levels (Feb. 1-10):

- For the most part, Texas sent less natural gas out, which is represented by outflows showing negative figures. Therefore, Texas sent less natural gas out to LNG, Mexico and the West (SW toward California).
- Texas only received more natural gas from South LA (+1 Bcf/d), specifically from TETCO and Transco pipelines.

Inflows/Outflows (Bcf/d)	Feb 1-10	Feb17-20	Delta
Permian to SW	0.6	0.1	-0.5
Permian to MidCon Prod	1.0	0.5	-0.5
LNG	3.3	1.0	-2.3
Mexico	1.7	1.2	-0.5
ArkLa	2.4	0.9	-1.5
Total Outflows	**9.0**	**3.7**	**-5.3**
South LA to Houston	0.9	1.9	+1.0
MidCon Prod to NE Texas	0.6	0.1	-0.5
Total Inflows	**1.5**	**2.0**	**+0.5**

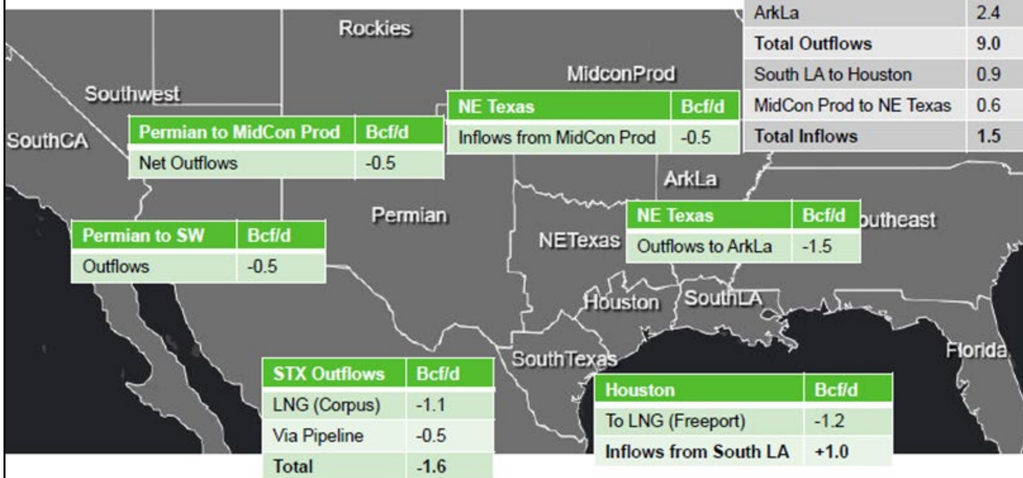


Figure 55: Texas Natural Gas Inflows and Outflows, February 1 – 20, 2021

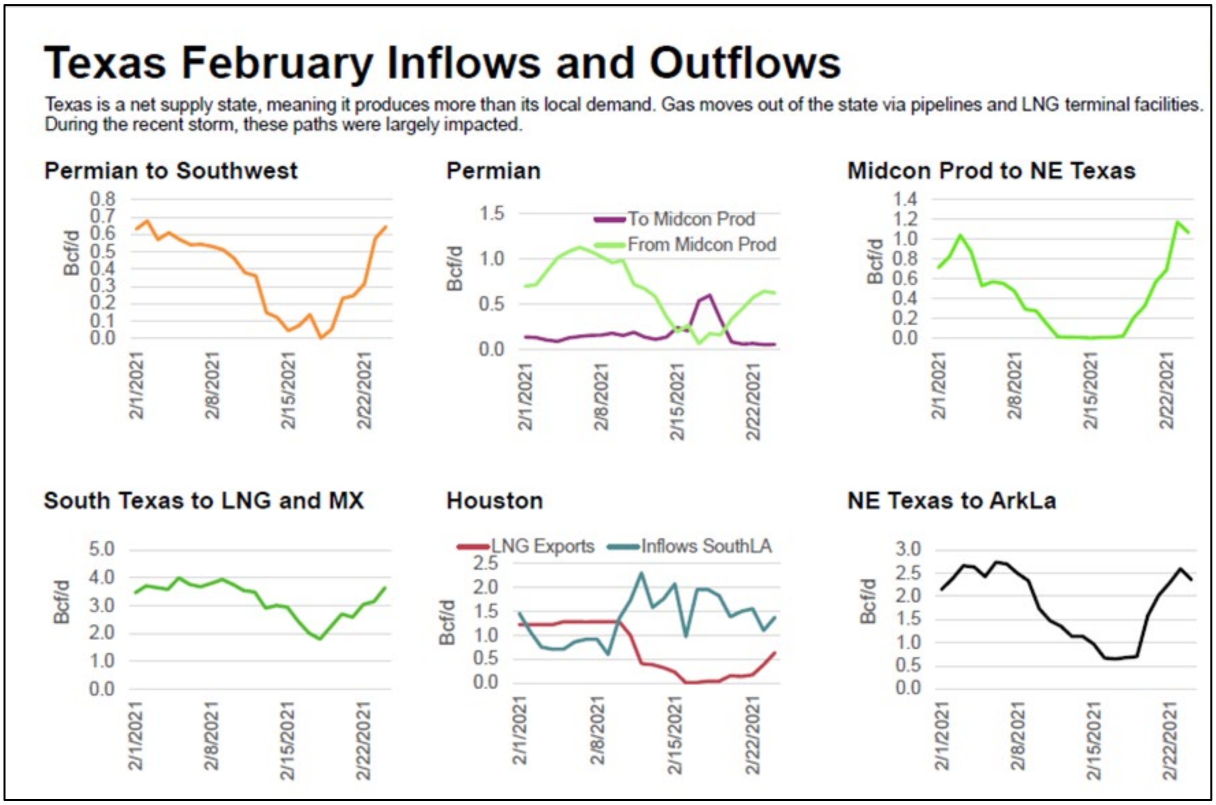
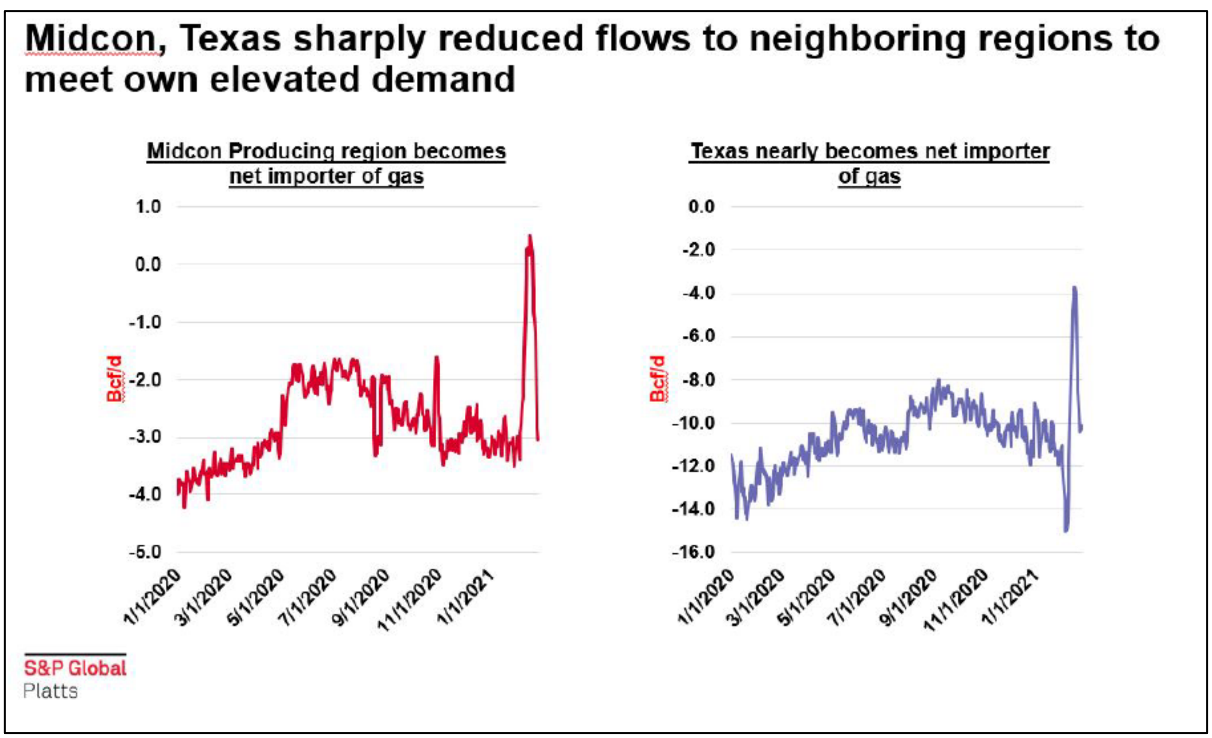


Figure 56: Texas Natural Gas Flow Changes to Neighboring Regions

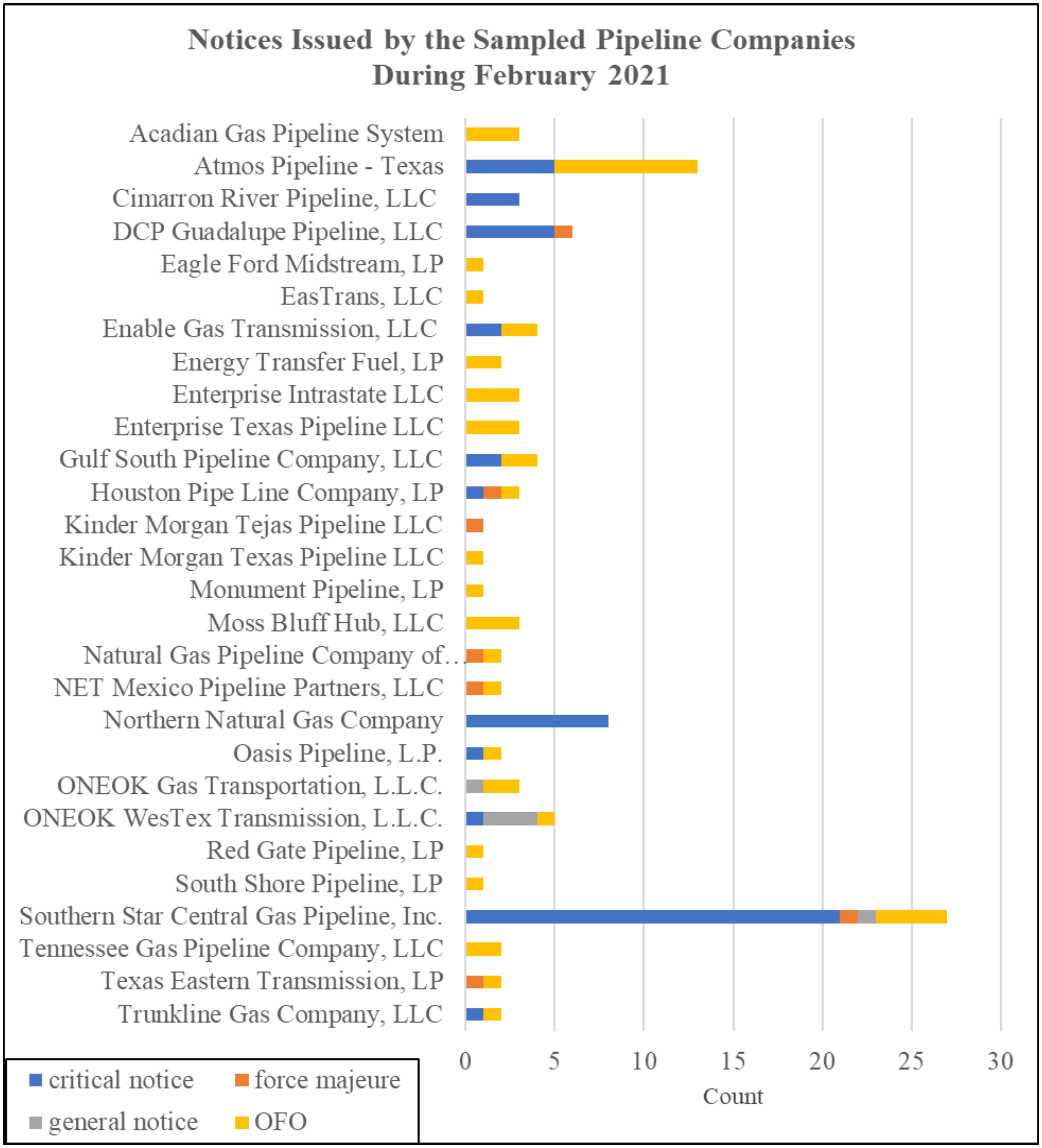


c. Natural Gas Pipeline Conditions - February 14 - 20

During the Event, interstate and intrastate natural gas pipelines throughout the Event Area were only minimally affected by power outages (because most used natural gas-fired compressors and have backup power for control systems) and were largely able to meet their firm transportation commitments. Seven pipelines issued notices of force majeure that affected 14 firm shippers, including four natural gas-fired generating units. See Figure 57, below. Intrastate Kinder Morgan pipelines issued force majeure notices to their non-human-needs industrial customers under the Texas RRC's emergency order. Pipeline communications via system-wide OFO, critical, and other notices conveyed to customers that the pipelines were in an emergency situation and would not tolerate customers shorting the pipelines[190] or going over their capacity allotment.

[190] "Shorting" a pipeline occurs when a customer shipping gas on a pipeline system takes off more gas than its commodity seller had placed onto the system. This forces the pipeline to balance the supply shortfall. In periods of high demand, multiple shippers taking more than they placed on the system can lower the pipeline's system pressure. If the pipeline's operating pressure declines significantly, it can cause service reliability problems. Understanding this, during high demand periods, pipelines often issue critical notices, OFOs or low line pack warnings and impose stricter balancing tolerance levels. During the Event, pipelines were concerned about customers taking more gas than they were entitled to, so many issued low OFO penalties tightening the tolerance levels and imposing high OFO penalties (consistent with their tariff) for violations in order to discourage this behavior.

Figure 57: Notices Issued by Pipeline Companies During February 2021



<u>February 14 through 16.</u> On February 14, as colder weather and freezing precipitation moved throughout the Event Area, more natural gas processing plants reported outages that were attributed to either lack of natural gas supply, mechanical failure due to weather, or power outages. During this timeframe, pipelines issued the greatest number of critical notices for the need to curtail deliveries, primarily due to loss of natural gas supply. For example, at 8:30 a.m. on the morning of February 14, Northern National Gas Company, the largest interstate pipeline company in the U.S., issued a critical notice effective for the gas day beginning at 9 a.m. on Monday, February 15. The notice mentioned temperatures would be "well below normal" through the weekend, and that "Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects." Also, on February 14, the first force majeure notices were issued by an intrastate natural gas pipeline in ERCOT, because of lack of natural gas supply and a pipeline equipment failure. These force majeure notices resulted in a limited number of delivery curtailments to natural gas-fired generating units in ERCOT with firm natural gas transportation contracts.

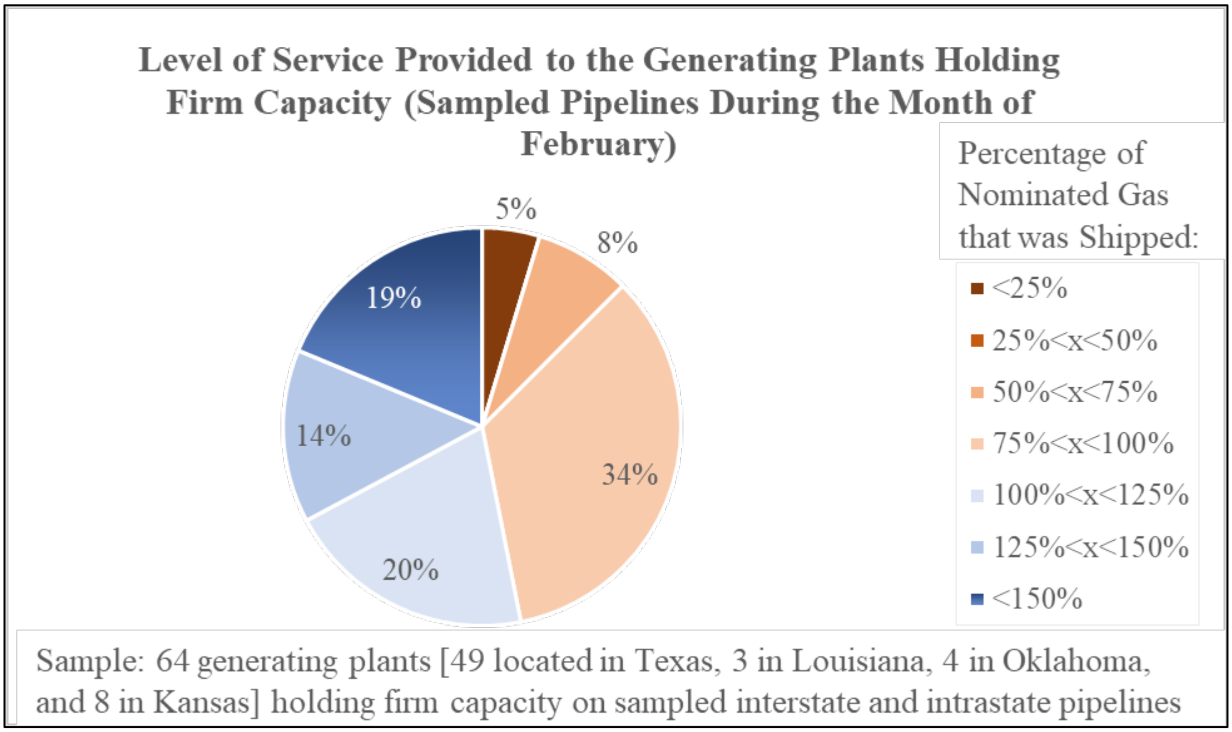
On February 15 and 16, after ERCOT had ordered firm load shed, several force majeure notices were issued which resulted in curtailment of natural gas deliveries. Causes included compressor station mechanical problems, loss of compressor electric power supply, and curtailments to industrial natural gas customers due to the RRC's emergency order for priority for human needs. Some of these force majeure conditions lasted through February 18.

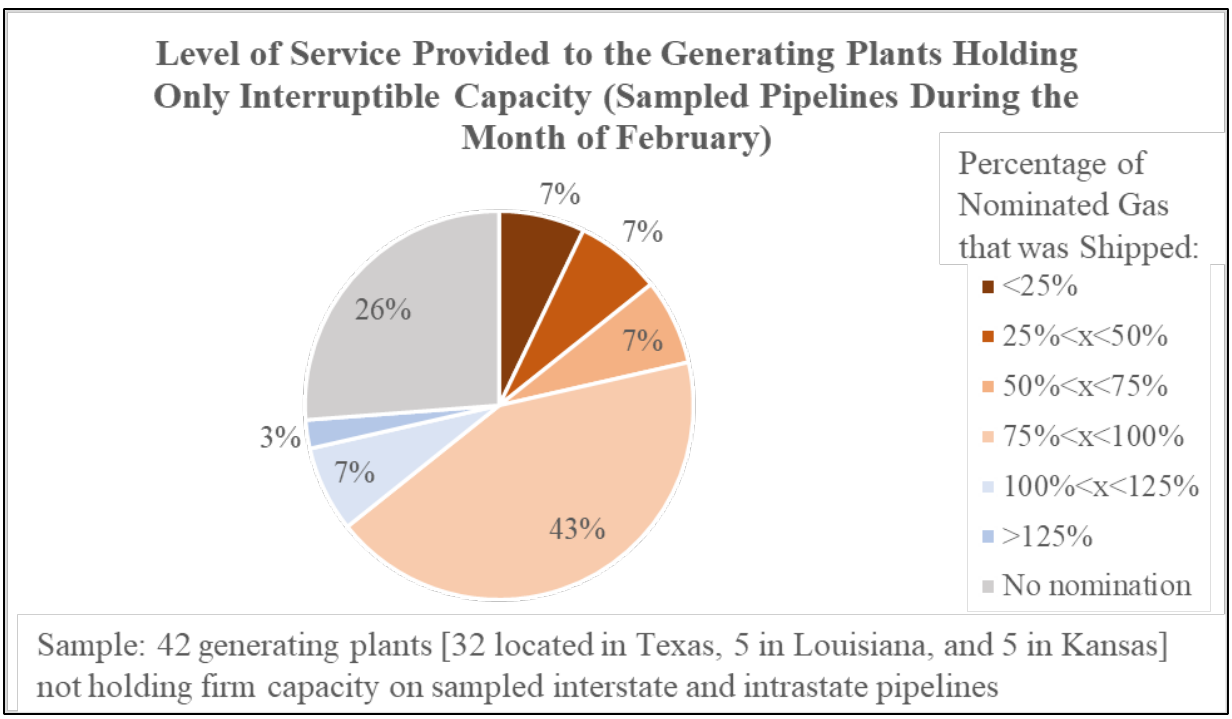
February 17 through 20. Intrastate and interstate pipelines continued to issue critical notices during this period, primarily due to natural gas supply shortfalls, but to a lesser extent, because weather conditions gradually improved. Although there were no declarations of force majeure, pipelines issued several OFOs due to declines in both natural gas supply and line pack.

Over the entire Event, despite the issuance of some force majeure notices and OFOs, interstate and intrastate pipelines were able to ship a substantial percentage of the gas nominated by firm shippers. Thirteen pipelines provided daily data which the Team used to evaluate the level of transportation service provided to natural gas-fired generating units during the month of February. Specifically, the Team examined the daily amount of gas each generating unit (referred to as "plant" by the pipeline) nominated and what percentage of that nominated gas was actually shipped. Over half of the generating plants holding firm capacity on the sampled pipelines (53 percent) had 100 to 150 percent or more of their nominated gas shipped.[191] Most generating plants that did not hold firm capacity still had some gas shipped: over fifty percent of the generating plants holding only interruptible capacity had 75 to over 125 percent of their nominated gas shipped. Marketers are not represented in this data. See Figure 58, below.

[191] As shown in Figures 59 and 60 below, the nominations were not always consistent with contracted volumes.

Figure 58: Level of Service Provided to the Generating Plants Holding Firm Capacity (Sampled Pipelines During the Month of February)





The graphs in Figures 59 and 60, below, depict interstate and intrastate volumes nominated, volumes shipped and volumes contracted throughout the Event Area, demonstrating the potential value of firm transportation during the winter months and underscoring that the peak for natural gas as a whole still occurs during the winter months, although natural gas-fired generating units often serve a summer peaking region (as in ERCOT).

Figure 59: Firm Natural Gas Pipeline Capacity Contracting and Scheduling by Natural Gas-Fired Generating Plants – Interstate Pipelines

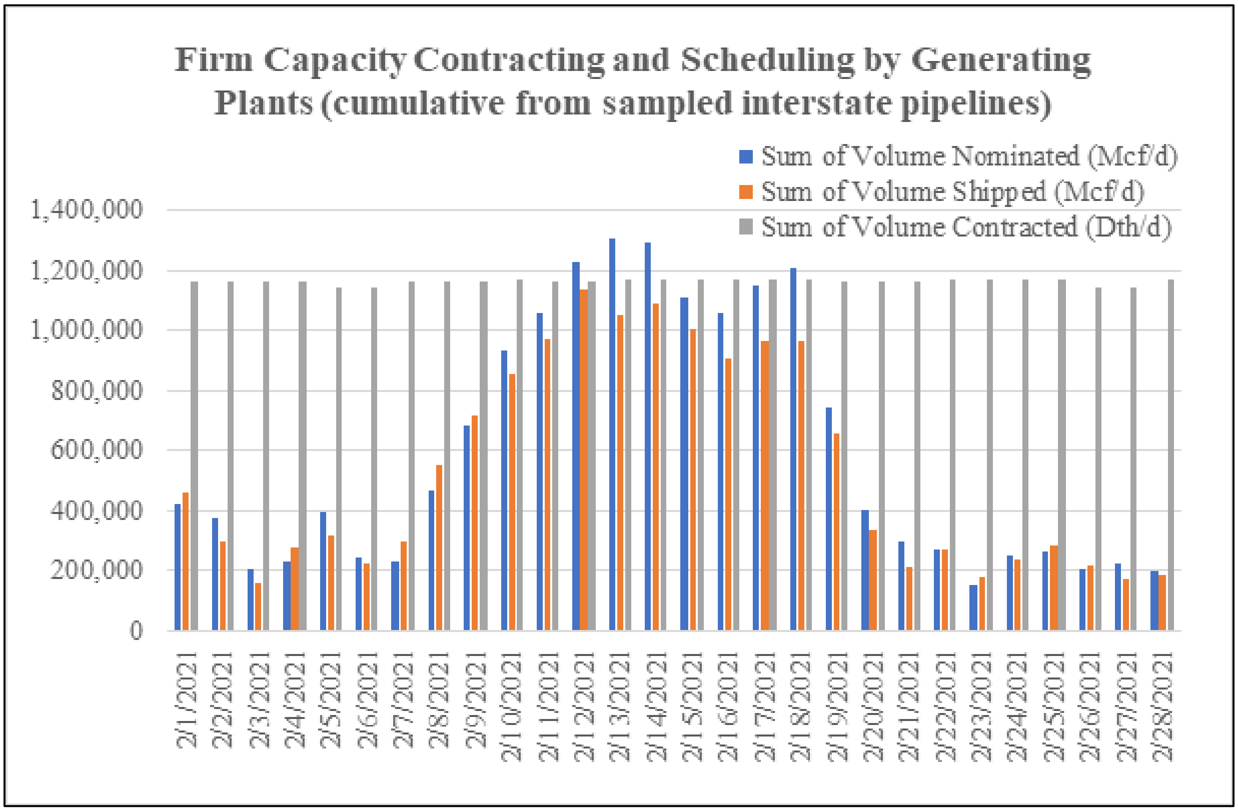
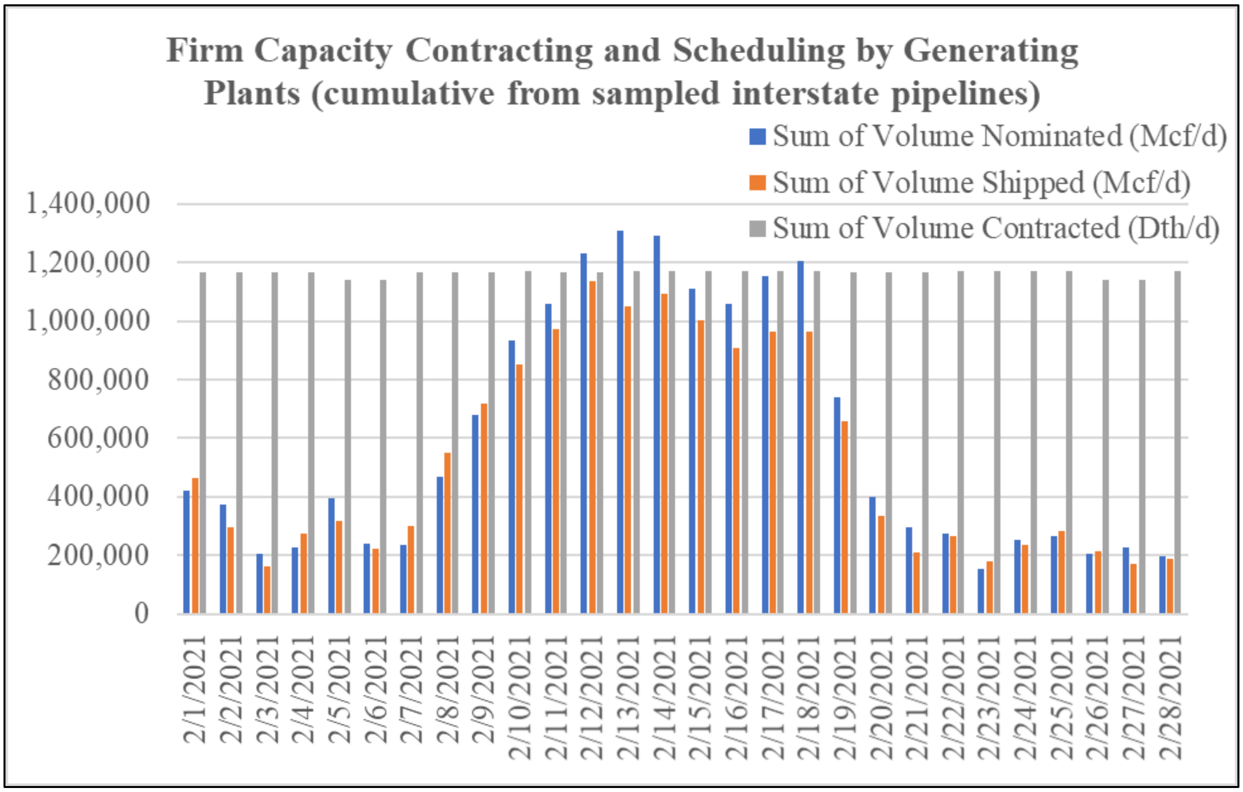


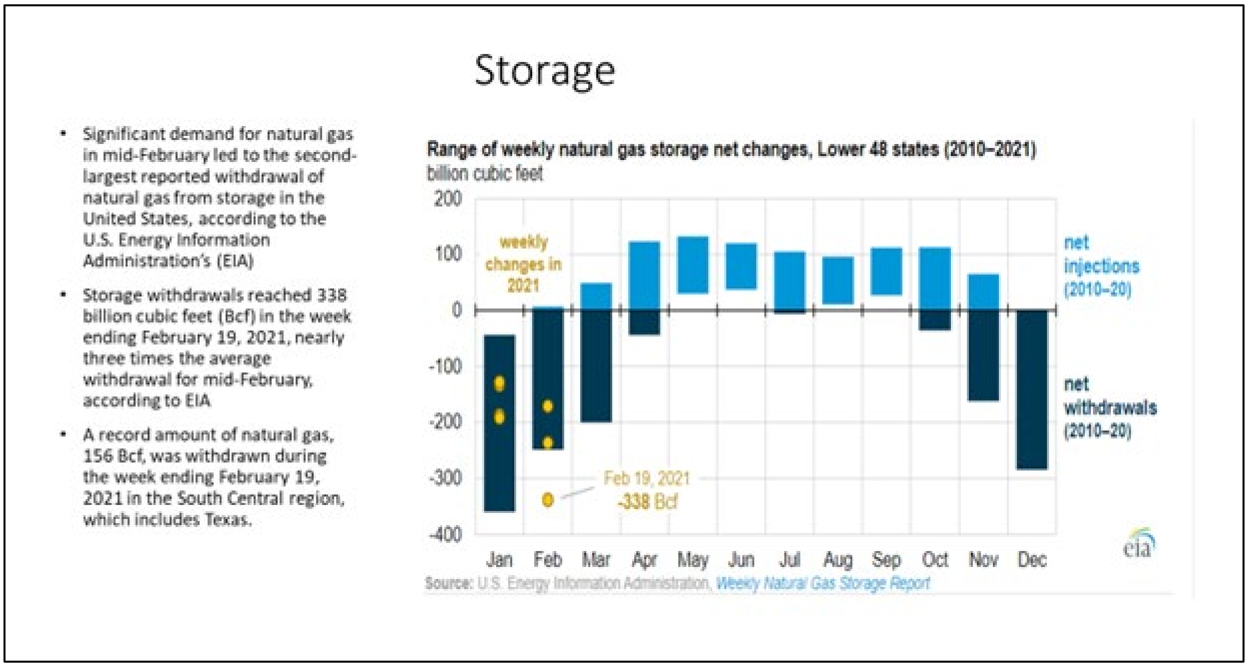
Figure 60: Firm Natural Gas Pipeline Capacity Contracting and Scheduling by Natural Gas-Fired Generating Plants – Intrastate Pipelines



d. Natural Gas storage

Natural gas pipelines and shippers were able to meet their obligations partly due to the effective use of production- and market-area storage fields. Hit with the combination of freeze-induced natural gas production declines in Texas and the South Central U.S., increased natural gas consumption from residential and commercial customers, and increased demands from natural gas-fired generating units, pipelines and shippers relied on storage facilities, making record withdrawals for February, as shown in Figure 61 below. Pipelines made storage injections prior to the Event and withdrawals during the Event to meet natural gas demand in the Event Area.

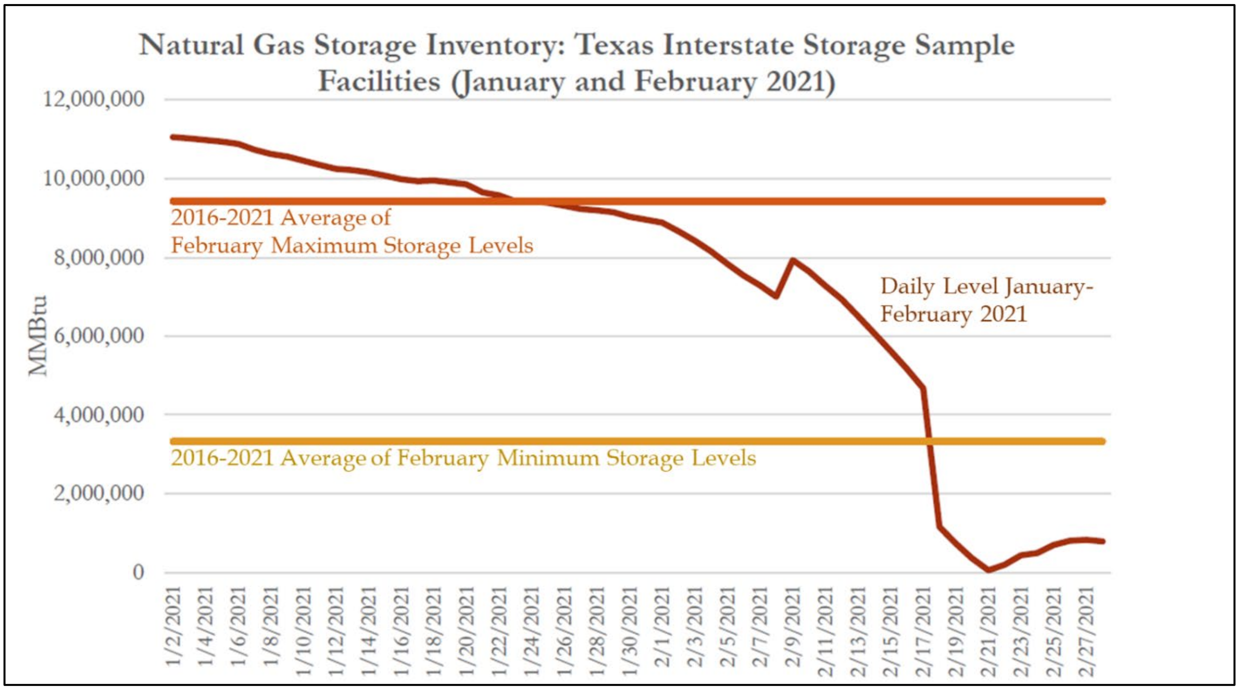
Figure 61: Natural Gas Storage Withdrawals and Injections, Lower 48 States (2010 to February 2021)[192]



Storage fields reached maximum withdrawal rates between February 17 and 18 (as shown in Figure 62 below), based on a sample of daily levels at five interstate storage facilities compared to average levels for February over the past six years. Most storage fields did not see injections restart until February 21. Storage generally performed as expected relative to its inventories, pressures, and deliverability curves throughout the Event.[193]

[192] United States Energy Information Administration (EIA), *Cold weather results in near-record withdrawals from underground natural gas storage*, Today in Energy (Feb. 26, 2021), https://www.eia.gov/todayinenergy/detail.php?id=46916.
[193] UT Report at 47.

Figure 62: Natural Gas Storage Inventory[194]



e. Natural Gas Pipeline Outages

Natural gas pipelines were largely unaffected by wide scale power outages. Notably, most compressor stations are gas-powered, and pipelines have backup generators and/or batteries at their major facilities. Isolated electrical power loss occurred at compressor stations, storage facilities, and meter stations. Figure 63, below describes reported natural gas pipeline outages due to power loss that impacted pipeline flows.

[194] UT Report, Figure 2w (attributed to Wood Mackenzie).

Figure 63: Natural Gas Pipeline Power Outages that Impacted Flows

Date(s)	Facility(ies)	Cause	Effect
2/15/21	One compressor station	Loss of commercial electric power	Deliveries curtailed until backup generation became available
2/15/21	Storage facility	Loss of commercial electric power	55% reduction of maximum withdrawal capacity for about eight hours
2/15-2/16/21	Two compressor stations	Loss of commercial electric power	Issued a Force Majeure notice, impacted one commercial, non-generating-unit location
2/16-2/18/21	One compressor station	Loss of commercial electric power, failure of backup generator	Issued a Force Majeure notice
2/19/21	Meter station	Loss of commercial power	Unable to receive gas for about seven hours
2/16/21	One compressor station	Loss of commercial power	Fell short of nominated volumes
2/14-2/15/21	Storage facility	Losses of commercial power (twice)	Interrupted operation of the glycol dehydration unit, reducing operational ability
2/17/21	Meter station	Loss of power, backup generator failed	Unable to receive gas for about two hours until portable generator delivered

Approximately a third of the pipelines that provided data to the Team (10 of 32) had some facilities (meter stations, compressor stations, storage facilities) designated as protected or critical load. All pipelines had backup generators and/or batteries at their major facilities. None of the pipelines participated in demand response programs. Only approximately 16 percent of the 128 reported pipeline-related events affecting compressor stations resulted in associated flow reduction.[195] The majority of the 128 pipeline-related events were the result of mechanical issues that did not affect operations, and since the majority of pipelines deployed personnel to compressor stations around-the-clock, even compressor station events that affected operations were resolved on average within 25 hours.

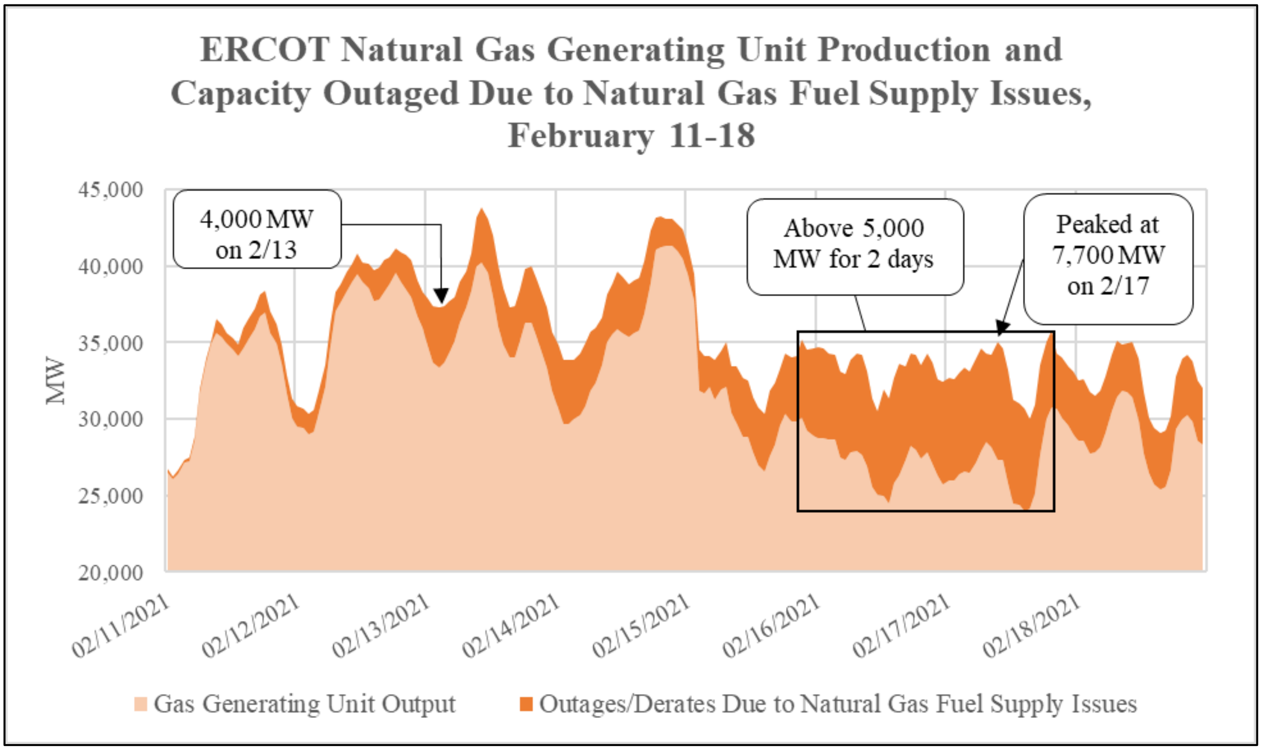
[195] Only four of these events were related to power outages (whether caused by rotating load shed or local, weather-related distribution outages). They are described in more detail in Figure 63, above.

3. Unplanned Generating Unit Outages Begin to Escalate

Increased Generating Unit Outages Due to Natural Gas Supply Issues. On February 14, the ERCOT, SPP and MISO footprints combined averaged over 10,300 MW in generating unit outages and derates due to natural gas fuel supply issues. Going into February 15, ERCOT had approximately 2,300 MW of unplanned generating unit outages and derates due to natural gas fuel supply issues, while SPP had over 6,000 MW and MISO South had 700 MW.

As natural gas fuel supply issues worsened during the week of February 14, reductions in natural gas-fired generating unit output followed, as shown in Figure 64, below.

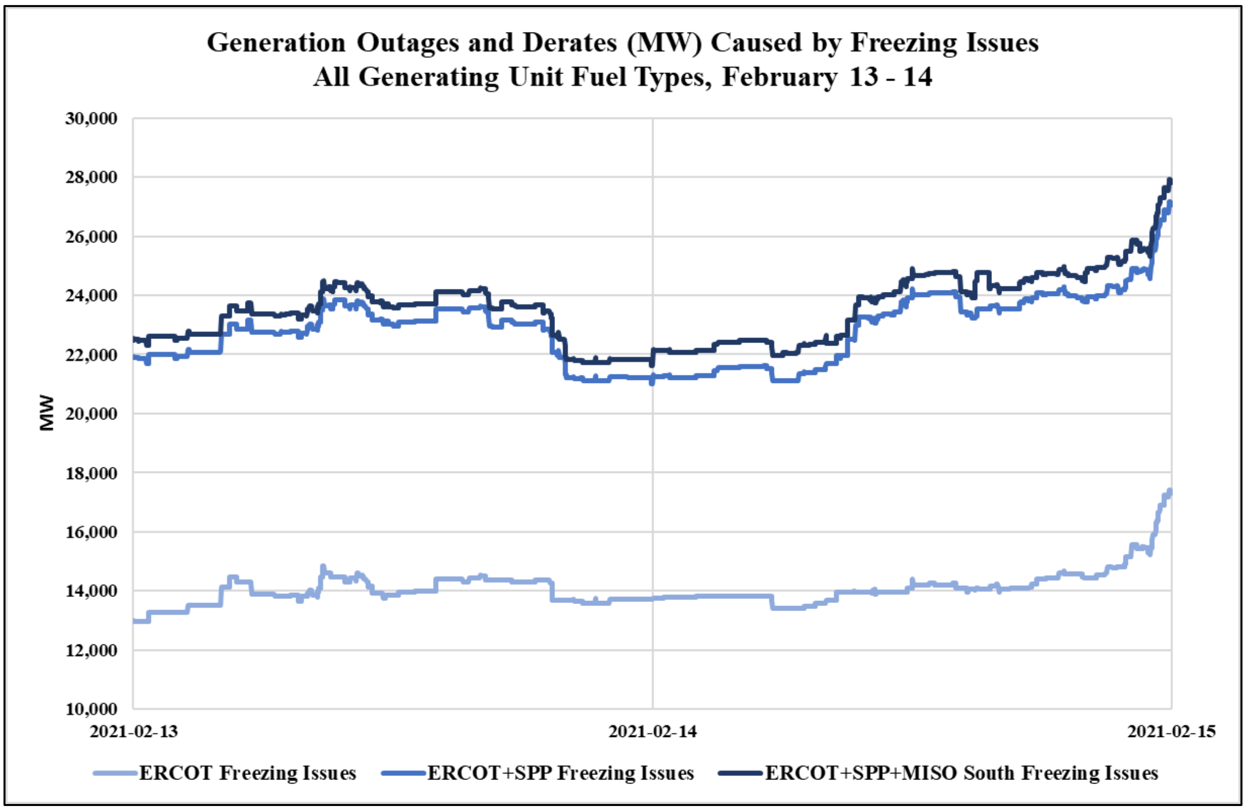
Figure 64: ERCOT Natural Gas-Fired Generating Unit Production and Capacity Outaged Due to Natural Gas Fuel Supply Issues, February 11 – 18



Additional Generating Unit Outages due to Freezing Issues. By the weekend of February 13 and 14, ERCOT unplanned generating unit outages and derates due to freezing issues averaged over 14,000 MW. ERCOT had all available units operating on February 14, in an attempt to avoid failures to start. Temperatures in Dallas fell to four degrees by the morning of February 15, compared to a normal daily minimum temperature for the same day of 39 degrees, accompanied by freezing precipitation and wind in a large portion of the Event Area. Additional generating units experienced freezing issues, resulting in a sharp upward trend in the number of generating unit outages and derates in the Event Area by the late evening hours of February 14, into the early morning of February 15. At the start of February 15, the number of freezing-related unplanned generating unit outages increased sharply to over 17,400 MW.

Over the weekend of February 13 and 14, in SPP, generating unit outages and derates due to freezing issues averaged over 8,700 MW, increasing to over 9,700 MW by the start of February 15. In MISO South, generating unit outages and derates due to freezing issues were still relatively minimal as compared to ERCOT and SPP (as seen in Figure 65, below), since the colder temperatures and freezing precipitation arrived there after reaching SPP and ERCOT. MISO South cumulative freezing-related generating unit outages and derates averaged 700 MW. ERCOT, SPP and MISO freezing-related generating unit outages and derates in total climbed from approximately 22,400 MW to 27,800 MW during the period from February 13 to the start of February 15, as shown in Figure 65, below.

Figure 65: Generation Outages and Derates Due to Freezing Issues – February 13 - 14



To gain additional insight on generation unavailable during early part of the week of February 14, Figure 66a, below, provides perspectives on total unavailable generation (including the causes of the unplanned generation outages) at different times on February 14 through 16, as compared to the onset of the cold weather (February 8) within the three BA footprints, and for the entire Event Area. Figures 66b and 66c illustrate the total unavailable generation over time, by BA footprint. Total unavailable generation exceeded 90,000 MW in the Event Area on February 16 at 5 p.m., as shown in Figures 66a and 66c below.

Figure 66a: Unavailable Generation at Different Points in Time, February 14 -16[196]

		Point of Time During Event:						
Generation Outages and Derates (Nameplate MW)	***Before Onset of Colder Weather (MW)***	**As of Sunday Feb. 14 12 a.m. (MW)**	**As of Monday Feb. 15 12 a.m. (MW)**	**As of Monday Feb. 15 12 p.m. (MW)**	**As of Tuesday Feb. 16 12 a.m. (MW)**	**As of Tuesday Feb. 16 12 p.m. (MW)**	**As of Tuesday Feb. 16 5 p.m. (MW)**	***Non-Coincident Event Area Peak Time (MW)***
ERCOT Footprint								
Planned:	3,079	1,859	1,859	1,859	1,859	1,812	1,812	1,812
Unplanned:	10,633							
Freezing Issues:		13,712	17,308	29,680	27,548	26,143	26,918	29,704
Fuel Issues:		4,259	2,435	4,194	6,239	6,320	6,746	4,400
Mechanical/Electrical Issues:		4,675	5,659	7,432	8,237	9,037	8,038	8,211
Other Issues:		238	1,015	3,617	2,164	1,778	1,598	3,617
Incremental Unplanned:		**12,251**	**15,784**	**34,290**	**33,555**	**32,645**	**32,667**	**35,299**
Total Unavailable:	13,712	**24,743**	**28,276**	**46,782**	**46,047**	**45,090**	**45,112**	**47,744**
Percent of Installed Capacity:	11.1%	20.1%	23.0%	38.0%	37.4%	36.6%	36.7%	38.8%
SPP Footprint								
Planned:	6,238	4,999	4,569	3,996	3,811	3,811	3,811	3,811
Unplanned:	11,264							
Freezing Issues:		7,292	9,744	11,520	11,672	11,311	11,634	12,472
Fuel Issues:		5,411	6,361	6,771	8,092	9,199	9,405	9,866
Mechanical/Electrical Issues:		3,680	4,561	4,225	4,027	3,937	3,911	4,297
Other Issues:		890	1,275	792	792	792	792	792
Incremental Unplanned:		**6,009**	**10,677**	**12,044**	**13,319**	**13,975**	**14,478**	**16,163**
Total Unavailable:	17,502	**22,272**	**26,510**	**27,304**	**28,394**	**29,050**	**29,553**	**31,238**
Percent of Installed Capacity:	18.6%	23.6%	28.1%	29.0%	30.1%	30.8%	31.4%	33.2%
MISO South Footprint								
Planned:	1,793	1,500	1,500	1,455	1,280	1,280	1,280	1,280
Unplanned:	1,406							
Freezing Issues:		606	756	4,938	5,219	7,607	8,247	8,247
Fuel Issues:		1,730	1,291	1,237	1,753	2,279	3,671	3,671
Mechanical/Electrical Issues:		1,971	1,231	2,006	1,958	2,342	2,873	2,873
Other Issues:		-	-	736	736	775	775	775
Incremental Unplanned:		**2,901**	**1,872**	**7,511**	**8,260**	**11,597**	**14,160**	**14,160**
Total Unavailable:	3,199	**5,807**	**4,778**	**10,372**	**10,946**	**14,283**	**16,846**	**16,846**
Percent of Installed Capacity:	7.6%	13.9%	11.4%	24.8%	26.1%	34.1%	40.2%	40.2%
Total Event Area								
Incremental Unplanned:		**21,161**	**28,333**	**53,845**	**55,134**	**58,217**	**61,305**	**65,622**
Total Unplanned:	23,303	**44,464**	**51,636**	**77,148**	**78,437**	**81,520**	**84,608**	**88,925**
Total Unavailable:	34,413	**52,822**	**59,564**	**84,458**	**85,387**	**88,423**	**91,511**	**95,828**
Percent of Installed Capacity:	13.3%	**20.4%**	**23.0%**	**32.6%**	**32.9%**	**34.1%**	**35.3%**	**37.0%**

[196] "Before Onset of Colder Weather" column refers to February 8, 12 a.m. Percent of Installed Capacity is based on 123,057 MW, 94,232 MW and 41,865 MW for ERCOT, SPP and MISO South, respectively. The "Non-Coincident Event Area Peak" of unplanned generation outages and derates was 65,622 MW, which occurred at different points in time: in ERCOT on February 15 at 1:05 p.m., MISO South on February 16 at 5:01 p.m., and SPP on February 17 at 12:17 a.m. The coincident peak of incremental unplanned generation in the Event Area was 61,305 MW which occurred on Tuesday, February 16 at 5 p.m., as shown in Figure 66a ("As of Tuesday, February 16, 5 p.m." column.).

Figure 66b: Total Unavailable Generation over Time, February 8 - 20, by BA Area

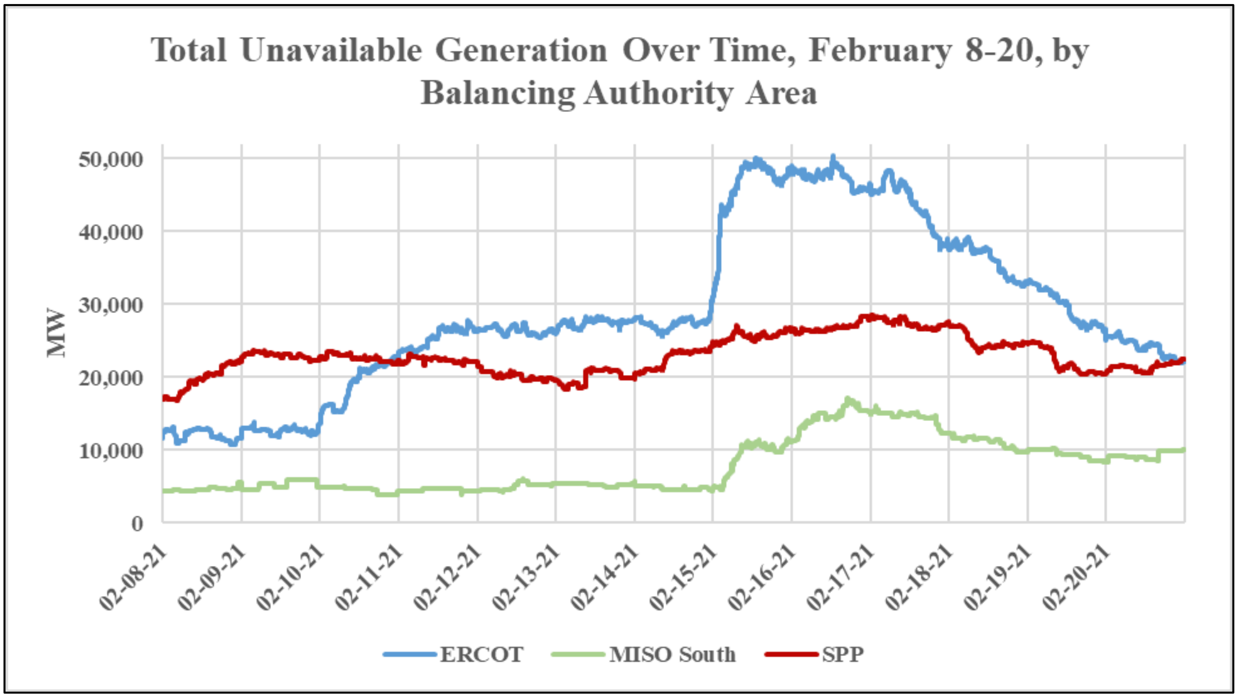
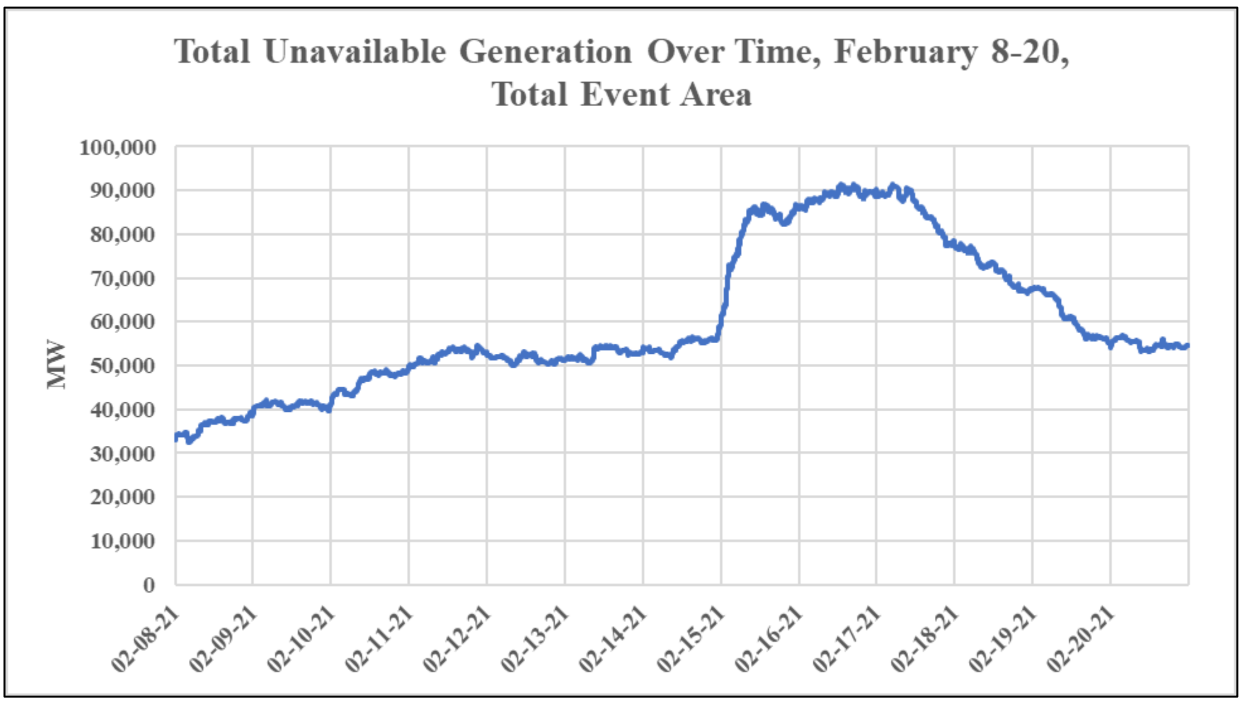


Figure 66c: Total Unavailable Generation over Time, February 8 - 20, Total Event Area



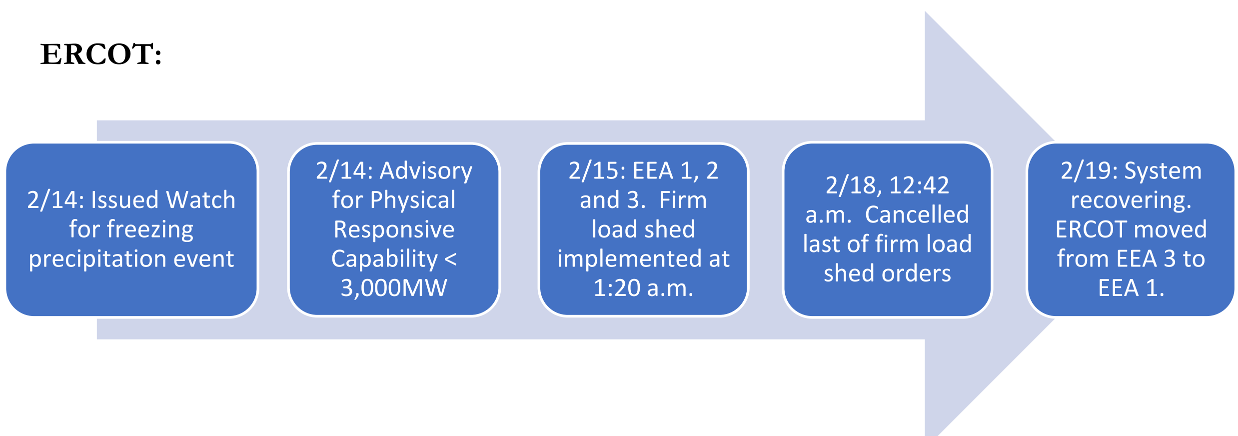
4. Grid Operators' Real-Time Actions Due to Unplanned Generating Unit Outages

a. Overview

With freezing precipitation and severe cold temperatures invading the region, ever-increasing unplanned generating unit outages, coupled with forecast record- or near-record peak electricity demands for February 15 and 16, ERCOT, SPP and the MISO BA and RC operators were faced with "the perfect storm." Increases in generating unit unavailability continued in ERCOT, MISO South and SPP, and all three declared energy emergencies during the week of February 14 for this core reason. The most prominent problem that faced ERCOT and SPP grid operators was balancing load against remaining available electric generation output. ERCOT's challenge was most severe, due to the magnitude of unplanned generating unit outages in its area, coupled with its limited ability to import power to help offset generation shortfalls.[197] While MISO and SPP had the ability to import power from the east where weather conditions were less severe to make up for a large portion of their generation shortfalls, they reached transmission limits in doing so (only so much power could be reliably imported), requiring MISO to declare transmission emergencies[198] in addition to SPP and MISO South's energy emergencies. Figure 67, below, provides a summary of the alerts declared by all three entities during the week of February 14, 2021.

Figure 67: Alerts Issued by ERCOT, SPP and MISO, February 14-20, 2021

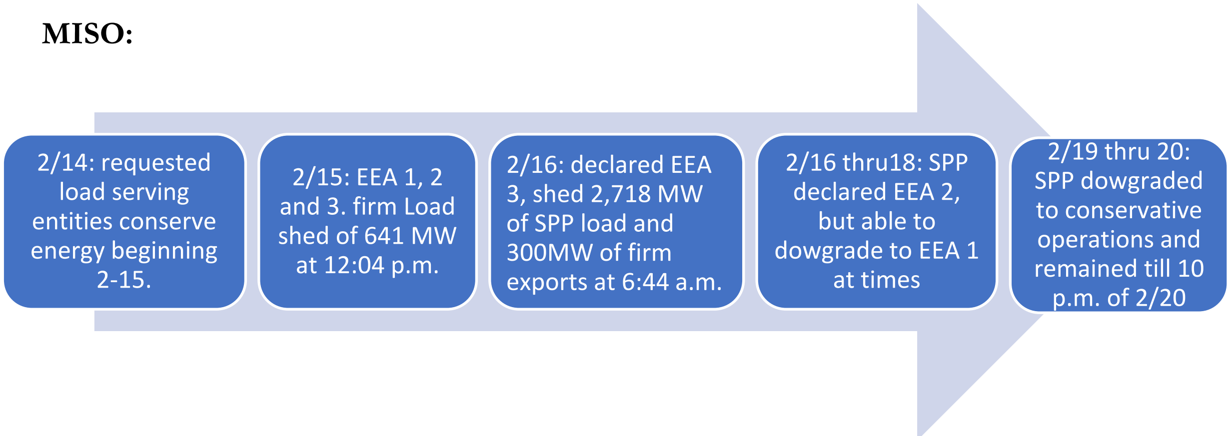
ERCOT:



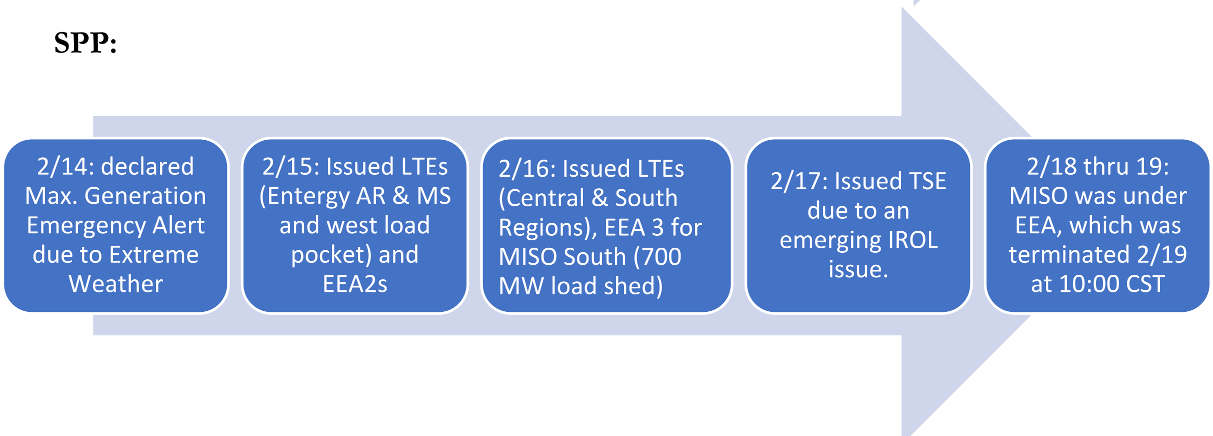
[197] The entire ERCOT Interconnection has a maximum total import limitation of only 1,220 MW over its direct current ties with SPP (Eastern Interconnection) and CENACE (Mexico). ERCOT did schedule power to be imported to the extent available from the Eastern Interconnection. ERCOT, unlike MISO and SPP (who collectively imported nearly 13,000 MW) did not have the ability to import many thousands of MW from the Eastern Interconnection. Had ERCOT been able to import more power, it likely would have decreased the amount that MISO and SPP would have been able to import.

[198] At different times and locations, MISO declared local transmission emergencies (LTEs) and transmission system emergencies (TSEs) to maintain BES reliability.

MISO:



SPP:



b. ERCOT Operator Actions: Maintaining Frequency Despite Generation Outages to Prevent Grid Collapse

While ERCOT was able to avoid energy emergency measures through Saturday February 13, on Sunday, February 14, ERCOT was faced with even colder temperatures than Saturday, with the arctic air spreading into southern Texas, and additional electricity heating demands driving system load nearly ten percent higher than the day before.[199] At 9:21 a.m., ERCOT notified the PUCT that an EEA declaration might be needed that day. ERCOT had several ongoing 345kV transmission facility outages on Sunday, which primarily resulted from by freezing precipitation.[200] At 11:33 a.m. on February 14, similar to Saturday morning, ERCOT's Physical Responsive Capability[201] dropped

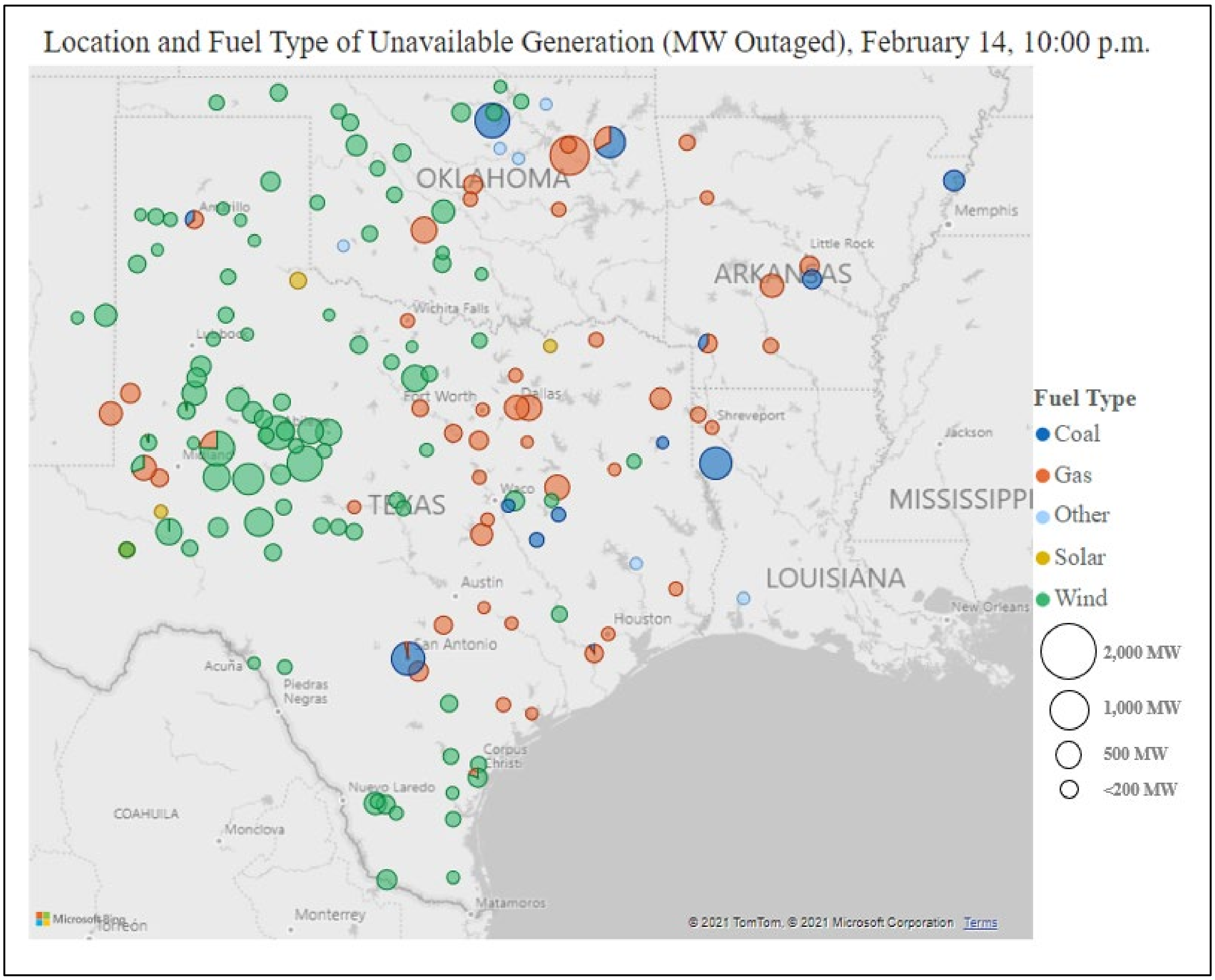
[199] On February 13, ERCOT peaked at 64,181 MW, but the next-day forecast for February 14 projected a peak of 70,327 MW (9.6 percent higher than the actual February 13 peak).

[200] Fortunately, these outages ended by Sunday evening, and the ERCOT RC/TOP implemented post-contingency mitigation measures to remain within system operating limits.

[201] Physical Responsive Capability values in this section are based on ERCOT's historical database of recorded values provided during the Event from the QSEs. ERCOT discovered after the Event that some QSEs were not updating the responsive reserve amounts for their generating units promptly during the Event. See Recommendation 23.

below 3,000 MW, which meant ERCOT BA no longer had sufficient contingency reserves above the current system load level. ERCOT issued an Advisory, meaning it recognized that conditions were developing such that GOPs and TOPs may need to take actions in anticipation of an EEA. At 3:17 p.m., ERCOT issued a Watch for a projected reserve capacity shortage, with no market solution available for hours ending 5:00 p.m. through 9:00 p.m., which translated to a high risk of an EEA event. On Sunday night, February 14, at hour-ending 8 p.m., ERCOT's system load reached an all-time winter peak of 69,871 MW, which remains ERCOT's highest recorded actual winter peak load to date, since ERCOT operators needed to shed large amounts of firm load on Monday and Tuesday. Then-committed generating units remained online during the Sunday evening peak and for about two hours more, so ERCOT BA operators did not need to declare an EEA.

Figure 68: Location of Unplanned Generation Outages and Derates, (MW Outaged), by Fuel Type, Total Event Area, February 14, 10 p.m.



System load decreased and Physical Responsive Capability recovered toward 3,000 MW after 9 p.m., and at 9:58 p.m., ERCOT cancelled its Watch for a projected reserve capacity shortage. Figure 68, above shows the generating unit outages in the Event Area as of February 14 at 10 p.m. The improved conditions in ERCOT did not last long.

At approximately 10:00 p.m. on February 14, and continuing into the early morning hours of February 15, unplanned generation outages and derates sharply increased, as shown in Figure 69, below. Over a three-hour period, approximately 6,000 MW of additional unplanned generation outages and derates occurred. These outages were primarily caused by freezing issues (52 to 60 percent of the outages during that period, as shown in Figure 70, below).

Figure 69: ERCOT Sharp Increase in Generation Outages and Derates

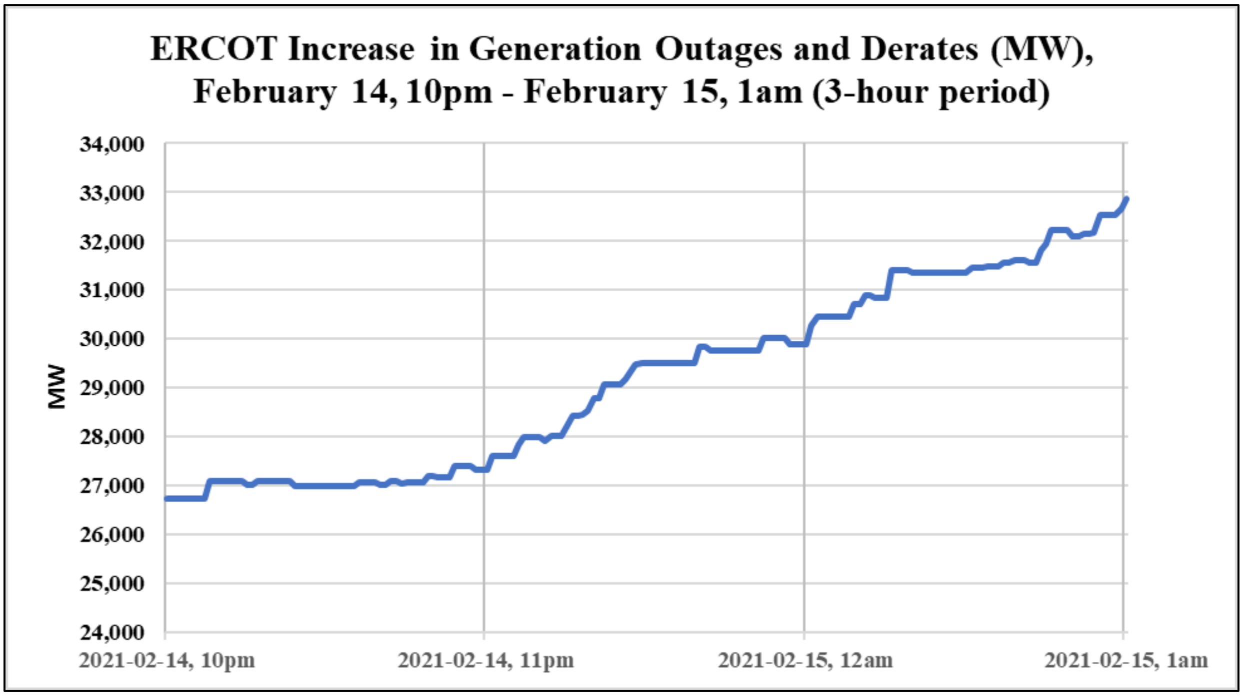
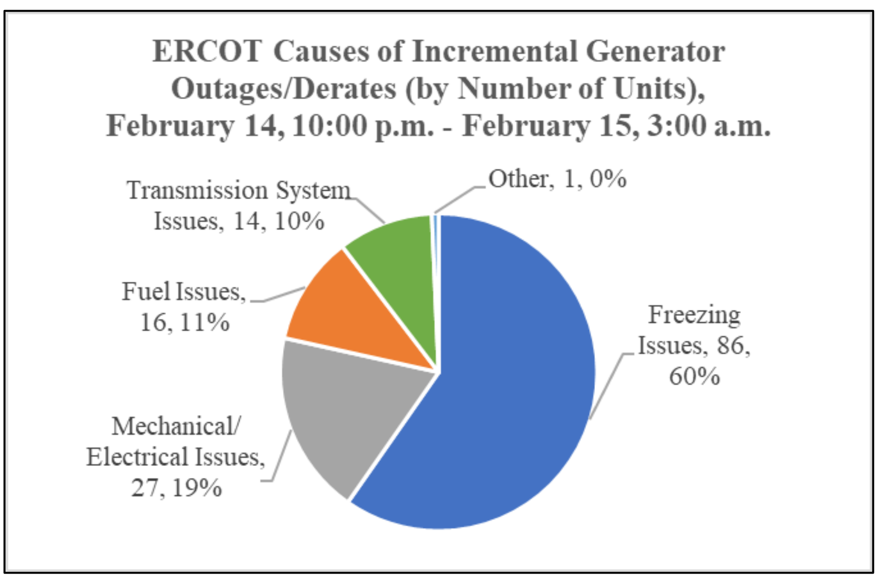
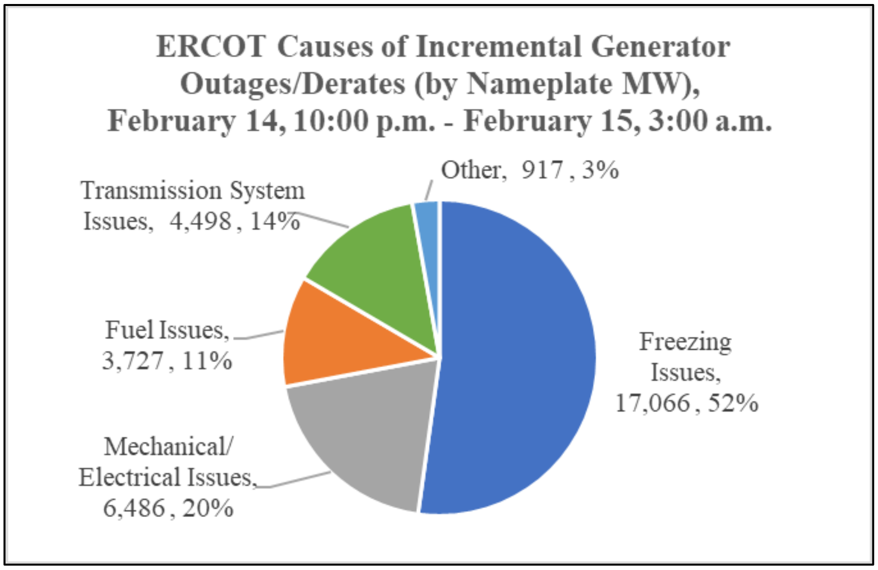


Figure 70: ERCOT Causes of Incremental Generator Outages/Derates, February 14, 10 p.m. – February 15, 3:00 a.m.





At 11:32 p.m., ERCOT issued an Advisory for Physical Responsive Capability less than 3,000 MW. ERCOT System Operators also issued two additional Advisories via hotline and ERCOT notifications due to Physical Responsive Capability falling below 3,000 MW.

Frequency Response Overview[202]

Frequency as a measure of the reliability status of a power system (in this case, ERCOT BA) can be likened to pulse or heart rate as a measure of human health. It provides a key indicator of the BA's continued ability to reliably meet demand. Maintaining frequency requires balancing a system's aggregate generation output to load moment-to-moment. It also requires having sufficient reserves of generation available at all times to withstand the sudden loss of the largest generator on the system, in order to instantaneously make up for the loss of power and reestablish balance.

Normal Frequency Control and Response

During normal operating conditions, system frequency is maintained through the automatic generation control (AGC) system, which maintains a balance between load and resources and keeps tie line flows at prescribed levels. In ERCOT, all external tie lines are DC converter stations, so the ERCOT system operates on a frequency bias only. Several generating resources automatically raise or lower their output at the direction of the AGC system to maintain frequency. This action is called secondary frequency response (SFR) and requires frequency responsive reserves to be effective for excursions in frequency.

[202] See Appendix E, Characteristics of Interconnection Frequency During the Event, for an in-depth look at the frequency and related characteristics of the ERCOT system during the Event.

A much faster-acting form of frequency control and response called primary frequency response (PFR) comes from automatic generator governor response, load response (typically from motors), and other devices that provide an immediate response (within seconds) to arrest and stabilize frequency in response to frequency deviations, based on local (device-level) control systems. Those actions are autonomous and are not directly controlled by the AGC system or the system operator. Again, the effectiveness of PFR is subject to the availability of "headroom" (unloaded "spinning reserves" on the online generation. For example, a generating unit with a maximum output limit of 500 MW and current output of 475 MW, could have 25 MW output available for PFR).

Tertiary frequency control is the next level of frequency management, in which a Balancing Authority redispatches generation, (e.g., starts additional generation), or calls on demand response to restore frequency responsive reserves for PFR and SFR following a low-frequency excursion. This action may include manual shedding of load by the system operator to restore reserves.

The need to maintain frequency to prevent a collapse of the system was the fundamental driving force behind ERCOT's decision to shed firm load. Because ERCOT is not synchronously connected to either the Eastern or Western Interconnections, all frequency response must come from resources internal to ERCOT's BA area. And because ERCOT is smaller than the other interconnections, the loss of any given generating unit results in a comparatively steeper frequency decline, necessitating a more robust frequency response. In 1988, ERCOT established a minimum responsive reserve requirement of 2,300 MW, based on an N-2 criterion—the simultaneous loss of two system elements, in ERCOT's case, covering one nuclear-powered unit and the next largest unit on the system. The purpose of the responsive reserves, both generation and load, is to ensure there is sufficient frequency response availability (i.e., Physical Responsive Capability)[203] arrest frequency declines before they reach 59.3 Hz (the trigger threshold for the first block of automatic underfrequency load shedding (UFLS. Should load resources be deployed manually by system operators, they are no longer available to provide frequency response. Should generation resources be dispatched to meet load, they would no longer be reserved to provide frequency response until recalled.

Frequency Conditions and The Decision to Shed Load

Load shedding is implemented to correct an electrical power imbalance if load exceeds supply and system operators cannot bring the system back into balance through other measures. Load shedding may be used to reduce an overload condition (such as when thermal limits on a transmission line are exceeded), to

[203] Physical Responsive Capability is a representation of the total amount of frequency responsive resource capability online in real time. ERCOT Nodal Protocols Section 2.1. It is calculated based on resource telemetry (e.g. from QSEs for generating units). ERCOT Nodal Protocols Section 6.5.7.5(1)(m).

> recover from an underfrequency condition, or to return voltage to a normal level. The operation can be manual (operator-initiated) or automatic (initiated by protective relays), depending on how quickly the frequency is decaying or the voltage is falling. For slowly-declining frequency or voltage issues, the manual option is usually chosen. For rapidly-declining frequency or voltage, the automatic relays will activate without operator intervention. ERCOT maintains and closely monitors its frequency responsive reserve levels (also referred to by ERCOT as its Physical Response Capability, or PRC), to comply both with its own 2,300 MW criterion and with the 1,430 MW minimum criterion required by NERC Reliability Standards.[204] ERCOT relies on demand-side load resources to provide up to 60 percent of its 2,300 MW responsive reserve requirement. These resources automatically disconnect when the frequency declines to 59.7 Hz.

i. ERCOT Frequency Decline and Recovery: February 15, Approximately Midnight to 2 a.m.

After ERCOT issued its advisory for Physical Responsive Capability dropping below 3,000 MW, at 11:32 p.m. on February 14, its frequency was 59.963 Hz, still within the normal range. Shortly after midnight heading into February 15, as generating units continued to trip or run back (also known as ramping down), ERCOT BA operators experienced the most dangerous two hours of ERCOT's existence. Due to the unrelenting generating unit losses during this period, the actions ERCOT BA operators took to restore Physical Responsive Capability and maintain normal frequency (initially, calling on demand response, then ordering small blocks of firm load shed) could not keep up, and frequency continued to drop. ERCOT BA operators were forced to shed larger blocks of firm load, and within minutes of one another, to restore frequency. Generating units failed at such a rapid pace that frequency dropped to the point of triggering a nine-minute time delay on generator underfrequency relays. Had ERCOT's frequency remained under this level for nine minutes, rather than over 4 minutes as actually happened, approximately 17,000 MW of additional generation would have tripped, potentially blacking out all of ERCOT. ERCOT BA operators were able to restore frequency to within the normal range by shortly after 2 a.m. and avoided tripping the underfrequency relays that could have caused a blackout, by shedding firm load as needed, to a cumulative total of 10,500 MW by 2 a.m. The following chronology examines the two-hour frequency decline and recovery in more detail. **All times are on February 15.**

From 12:06 a.m. through 12:11 a.m., four generating units ran back or tripped totaling 326 MW, and ERCOT's frequency declined to 59.940 Hz. At 12:10 ERCOT issued a Watch for Physical Responsive Capability less than 2,500 MW.

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[204] NERC Reliability Standard (Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability."

At 12:15 a.m., ERCOT entered emergency operations for the first time during the Event and declared an EEA 1[205] because its reserves dropped below the minimum responsive reserve requirement of 2,300 MW at 12:09 a.m. At 12:15 a.m., frequency was 59.958 Hz and Physical Responsive Capability was 2,269 MW.

At 12:15 a.m., in response to its responsive reserves dropping below 2,300 MW, ERCOT deployed 847.15 MW of 30-minute Emergency Response Service (ERS-30).[206] However, this deployment did not resolve ERCOT's low reserves because an additional five generating units totaling 473 MW had tripped or run back in the last 10 minutes.

From 12:35 a.m. through 12:54 a.m., five more generating units ran back or tripped totaling 428 MW. Frequency declined from 59.942 Hz to 59.911 Hz. At 12:57 a.m., one unit ramped down from 325 MW to 133 MW (tripping at 01:18), and another 41 MW tripped offline. At 12:59 a.m., ERCOT frequency fell below 59.91 Hz (to 59.908 Hz).

At 1:07 a.m., ERCOT declared an EEA 2[207] when it was unable to maintain frequency above 59.91 Hz for more than 7 minutes. ERCOT also deployed 51.6 MW of ERS-10.[208] Frequency had declined from 59.912 Hz to 59.872 Hz in about 10 minutes.

At 1:07 a.m., ERCOT issued an initial Verbal Deployment Instruction (VDI) to all QSE's representing Load Resources, preparing to deploy Groups 1 and 2 of those demand response resources. Frequency was at 59.868 Hz, and Physical Responsive Capability was 1,761 MW. At 1:11 a.m., ERCOT sent resource-specific electronic instructions to deploy Group 1 and Group 2. This action reduced load from 65,000 MW to 64,577 MW (a 423 MW reduction) and reduced Physical Responsive Capability load from 907 MW to 391 MW over the next five minutes. During this time, system frequency began to decline because of unplanned generation outages, and at 1:15 a.m., reached 59.88 Hz, although it recovered quickly—by 1:16 a.m., in response to ERCOT's EEA 2 actions, frequency recovered to above 59.95 Hz, within its normal range of 59.95 – 60.05 Hz.

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At 1:18 a.m., a generating unit tripped at 133 MW, resulting in a frequency drop from 59.955 Hz to 59.924 Hz (approximately 31 mHz).[209] This was a frequency sensitivity[210] of -2.59 mHz/second/100 MW loss. Figure 71 below illustrates the second-by-second change in ERCOT system frequency caused by losing even a relatively small generating unit at that time. Frequency dropped to 59.923 Hz before stabilizing at 59.934 Hz. Primary frequency response was limited at this time due to lack

205 According to the ERCOT operations desk procedures: EEA level 1 means that Physical Responsive Capability is less than 2,300 MW and is not expected to be recovered above 2,300 MW within 30 minutes without use of EEA level 1 procedures.

206 ERS-30 is Emergency Response Service, an aggregated demand response product that must be able to deploy in 30 minutes or less.

207 According to the ERCOT operations desk procedures: EEA level 2 means that Physical Responsive Capability is less than 1,750 MW, or operators are unable to maintain frequency above 59.91 Hz, and Physical Responsive Capability is not expected to be recovered above 1,750 MW within 30 min without use of EEA level 2 procedures.

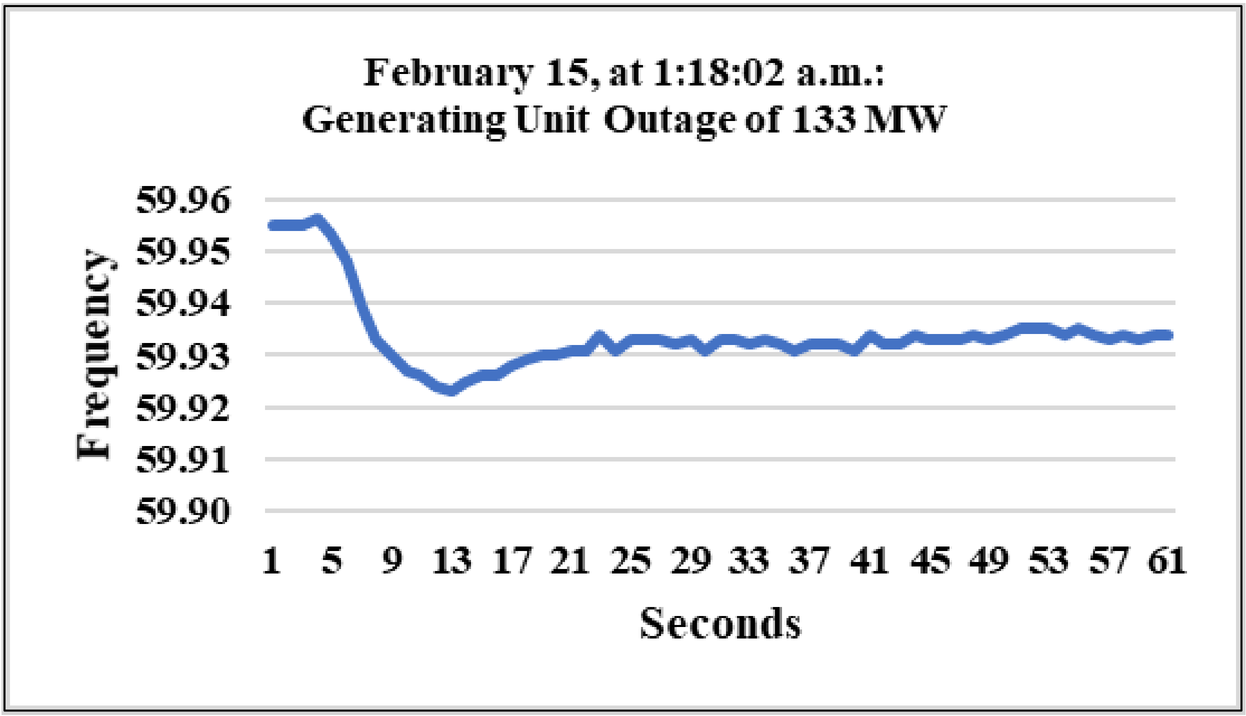
208 ERS-10 is another Emergency Response Service, similar to ERS-30, an aggregated demand response product, but must be able to deploy in 10 minutes or less.

209 Millihertz, which represents one-thousandth of a hertz.

210 The frequency sensitivity metric is described in greater detail in Appendix E.

of available headroom remaining for the generating units that were online and because turbine governors were already deployed in response to the low system frequency before the unit tripped.

Figure 71: Generation Outage and Effect on System Frequency, February 15 at 1:18:02 a.m.

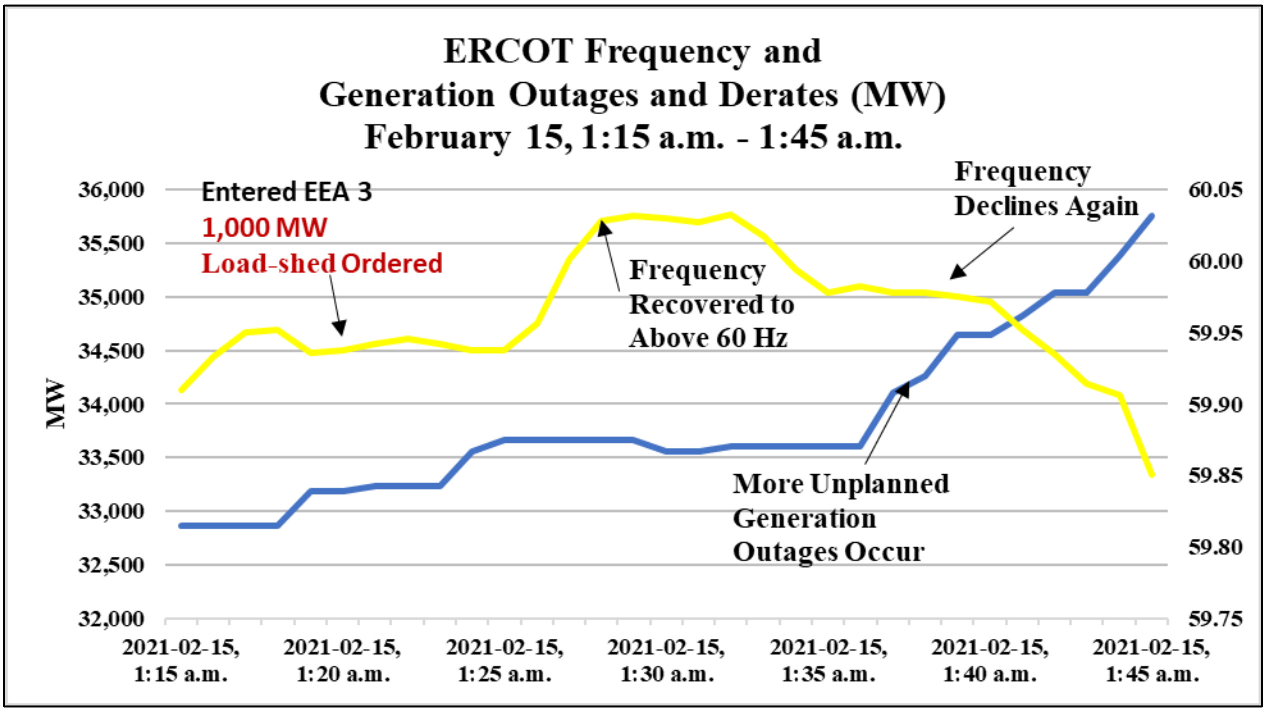


At 1:18 a.m., ERCOT Physical Responsive Capability fell below 1,430 MW (criteria for EEA 3) to 1,377 MW. Frequency was at 59.932 Hz. At 1:20 a.m., ERCOT declared EEA 3 and instructed TOPs to shed 1,000 MW of firm load. System load was 64,256 MW and frequency was 59.944 Hz.

At 1:20 a.m., a small generating unit tripped at 23 MW, resulting in a frequency drop from 59.942 Hz to 59.938 Hz in 4 seconds, a frequency sensitivity of -4.35 mHz/second/100 MW loss, showing that ERCOT BA's ability to respond was even less robust two minutes after the last frequency sensitivity calculation at 1:18 a.m. At 1:26 a.m., frequency recovered to 60.001 Hz after 1,000 MW of manual load shed, with load at 63,840 MW and Physical Responsive Capability at 1,281 MW, but soon began to decline. By 1:33 p.m., frequency declined to 59.975 Hz, a 45 mHz drop within one minute.

At 1:35 a.m. through 1:44 a.m., frequency dropped from 59.978 Hz to 59.823 Hz (a 155 mHz drop over almost 5 minutes) as over 1,500 MW more generating units in the ERCOT footprint experienced outages and run backs, causing frequency to steadily decline. Figure 72 below shows further increases in generation outages and derates and their effects on ERCOT frequency. ERCOT was about to enter the most dangerous 15 minutes of its history.

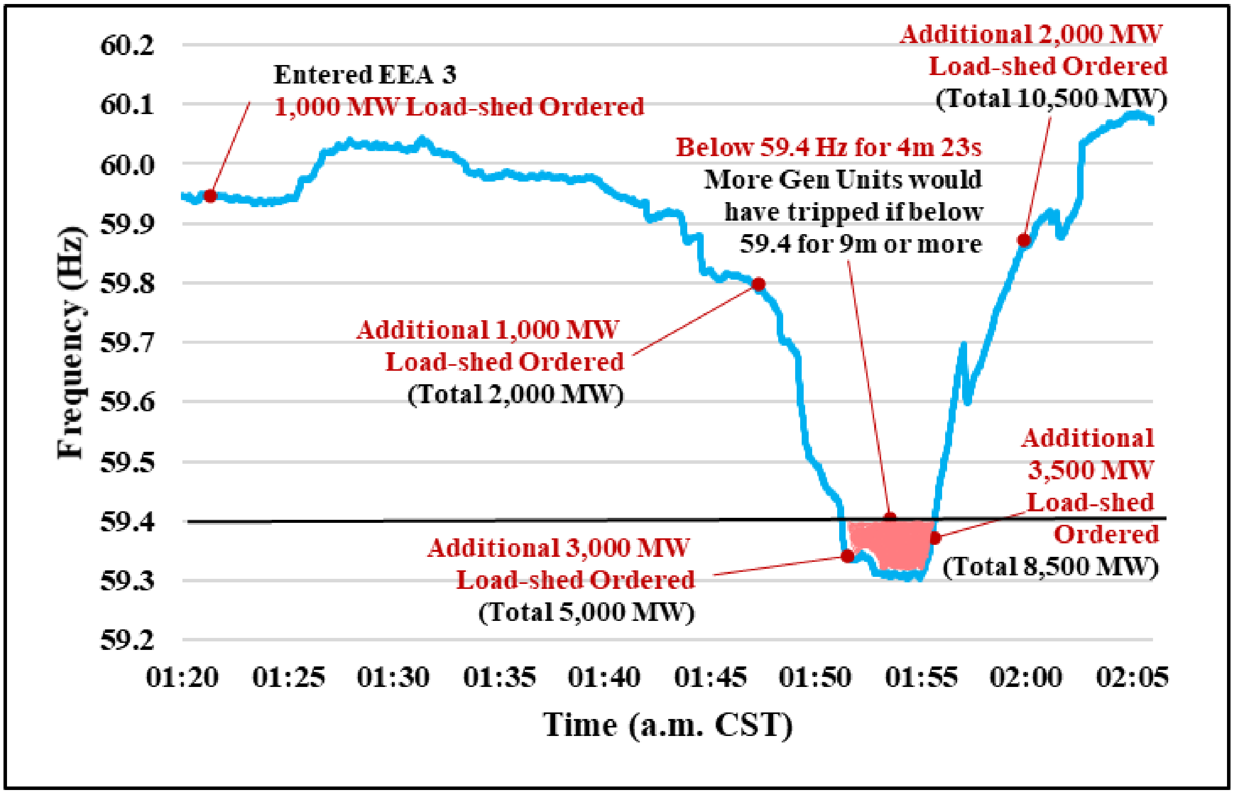
Figure 72: EEA 3 1,000 MW Firm Load Shed, Increase in Generation Outages and Derates and their Effects on ERCOT Frequency, February 15, 1:15 – 1:45 a.m.



From 1:44 a.m. through 1:49 a.m., another five generators tripped or ran back to zero output, totaling 1,712 MW within five minutes. Frequency fell from 59.817 Hz to 59.504 Hz, generation output was 61,205 MW, system load was 62,405 MW, and Physical Responsive Capability was 1,549 MW.

At 1:45 a.m., ERCOT instructed TOPs to shed an additional 1,000 MW of firm load (2,000 MW of firm load had been shed by that time), as indicated in Figure 73, below. Frequency was 59.820 Hz, generation output was 61,494 MW, system load was 62,690 MW, and Physical Responsive Capability had fallen from 1,694 MW to 1,267 MW in 10 minutes.

Figure 73: ERCOT System Frequency, February 15, 1:20 - 2:05 a.m.



At 1:51 a.m., frequency fell below the 59.4 Hz generator underfrequency relay trip level, starting the nine-minute time delay on those relays (see "Below 59.4 Hz for 4m 23s" caption and red shaded area in Figure 73, above). If the underfrequency relays had tripped, approximately 17,000 MW of generation would be outaged, potentially causing a total blackout of the ERCOT BA footprint. ERCOT ordered another 3,000 MW of load shed at 1:50 a.m., with total load shed then at 5,000 MW. Frequency was 59.496 Hz, generation output was 61,273 MW, system load was 61, 469 MW, and Physical Responsive Capability was 1,435 MW.

From 1:51 a.m. through 1:59 a.m., another three generators tripped or ran back to zero output, totaling 534 MW. At 1:54 a.m., ERCOT frequency reached its lowest level of the Event at 59.304 Hz. Generation output was 60,381 MW, system load was 61,590 MW, and Physical Responsive Capability was 1,044 MW. Approximately 276 MW of load tripped by UFLS relays at this time, although system frequency was not actually recorded as at or below 59.3 Hz, due to the close proximity of system frequency to the relay setpoints at 59.3 Hz.

At 1:55 a.m., ERCOT instructed TOPs to shed an additional 3,500 MW of firm load (total load shed was then 8,500 MW). Frequency was at 59.306 Hz, generation output was at 60,374 MW, load was at 61,583 MW, and Physical Responsive Capability was 1,403 MW.

At 1:55 a.m., frequency rose to 59.401 Hz, above the generator underfrequency relay protection trip level, after remaining below 59.400 Hz for four minutes and 23 seconds. However, ERCOT's system was not yet stable. Generation output was 60,120 MW, system load was 61,328 MW, and Physical Responsive Capability was 1,127 MW.

At 1:57 a.m., frequency rose to 59.689 Hz with system load at 60,454 MW and Physical Responsive Capability at 1,556 MW, but shortly thereafter, from 1:57 a.m. through 2:01 a.m. seven generators tripped or ran back, totaling 1,165 MW. The impact of this resource loss was offset by an additional 2,000 MW of load shedding ordered by ERCOT at 2:00 a.m., bringing the total load shed to 10,500 MW, as indicated in Figure 73, above. The combination of the 3,500 MW load shedding ordered at 1:55 a.m. and the 2,000 MW shedding ordered at 2:00 a.m. caused the frequency to continue to rise despite the loss of 1,165 MW of resources from 1:57 through 2:01 a.m.

At 2:02 a.m., system frequency rose above 60.0 Hz, with generation output at 57,002 MW, system load at 58,197 MW, and Physical Responsive Capability improved at 1,636 MW. The last 5,500 MW of load shed ordered was still taking effect. At 2:09 a.m., system frequency improved to 60.094 Hz as the effects of load shedding and resources losses balanced out. Generation output was at 53,578 MW, system load was 54,775 MW, and Physical Responsive Capability was a greatly-improved 2,952 MW.

By 2:30 a.m., ERCOT had ordered TOPs to restore 1,500 MW of load that had been shed, leaving 9,000 MW still disconnected, and had recalled other load resources that had been deployed. With frequency at 60.062 Hz and Physical Responsive Capability at 3,017 MW, the ERCOT system was considered stable.

Ultimately over the course of the Event, responsive reserves were less than 1,430 MW for approximately 4.5 hours on February 15, 1.9 hours on February 16, and 0.7 hours on February 17, and ERCOT shed a maximum of 20,000 MW of firm load by 7:00 p.m. on February 15. Throughout the low frequency event, ERCOT operators maintained system inertia.[211] Currently, ERCOT uses a critical inertia value of 94 GW-seconds, with 100 GW-seconds used as a minimum value for operations purposes. At 120 GW-seconds, ERCOT operators begin committing additional synchronous reserves and at 105 GW-seconds, they deploy non-spinning reserves. Inspection of the 1-second inertia data for the Event showed that system inertia during the period ranged from 254 GW-seconds to 349 GW-seconds, well above ERCOT's critical inertia level.

> **"What-if" Considerations**
> Had ERCOT lost a large contingency during the time that its Physical Responsive Capability was low, its reserves may have been insufficient to arrest the frequency decline above the first stage of underfrequency load shedding. The result may have been a sharp frequency decline which, when it crossed 59.3 Hz, would have triggered the first block of underfrequency load shedding, tripping five percent of ERCOT's system load. Even though the underfrequency load shedding would have tripped automatically, it would have taken out firm load and would be in addition to any firm

[211] Kinetic energy stored in spinning generators. "Inertial response provides an important contribution to reliability of the system in the initial moments following a generation trip event and determines the initial Rate of Change of Frequency [how quickly frequency initially declines]." Danya Pysh, *Inertia: Basic Concepts and Impacts on the ERCOT Grid*, ERCOT Pub. (Apr. 4, 2018), http://www.ercot.com/content/wcm/lists/144927/Inertia_Basic_Concepts_Impacts_On_ERCOT_v0.pdf.

> load that operators may have already shed. Depending on the circumstances surrounding the moment of activation of the automatic underfrequency load shedding, it is possible that an overvoltage condition could have occurred in one or more localized areas, that frequency could have significantly overshot the 60 Hz nominal frequency, or that other electrical perturbations could have developed that would have resulted in the tripping of even more generation. Only a detailed dynamic simulation could answer the question as to how widespread the February 2021 blackout would have been had the automatic underfrequency load shedding been triggered.

By 2:15 a.m., after beginning EEA 3 at 1:15 a.m. with 1,000 MW firm load shed, and having ordered a total of 10,500 MW of firm load shed, ERCOT system load had decreased by 10,745 MW (as shown in Figure 75, below). Although ERCOT would be required to shed additional firm load, peaking at 20,000 MW at 7:15 p.m. on February 15, ERCOT system operators had successfully faced the most dangerous challenge to the stability of the interconnection, and temporarily restored frequency to normal. ERCOT's fellow BAs MISO and SPP were facing their own emergencies caused by cold-weather-induced generating unit outages.[212] Figure 74, below shows the increase in generation outages in the Event Area, as compared to the conditions at 10 p.m. shown in Figure 68. Figure 75, below shows the trend of firm load shed in MW and change in ERCOT system load.

[212] Although both SPP and MISO South footprints experienced significant increases in generation outages and needed to declare emergencies, the Eastern Interconnection frequency remained within its normal range of 59.95 – 60.05 Hz during the morning of February 15.

Figure 74: Location of Unplanned Generation Outages and Derates, (MW Outaged), by Fuel Type, Total Event Area, February 15, 3:00 a.m.

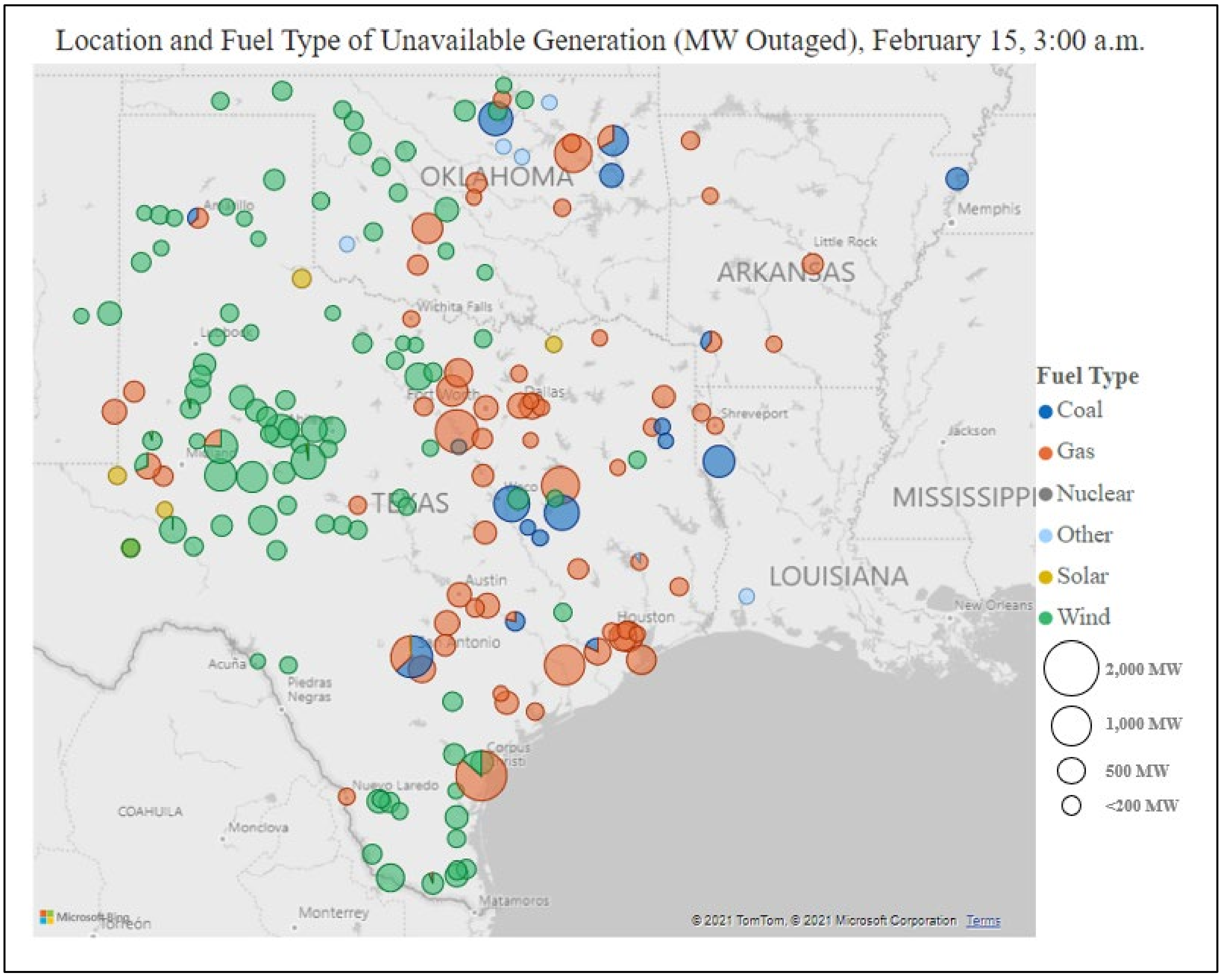
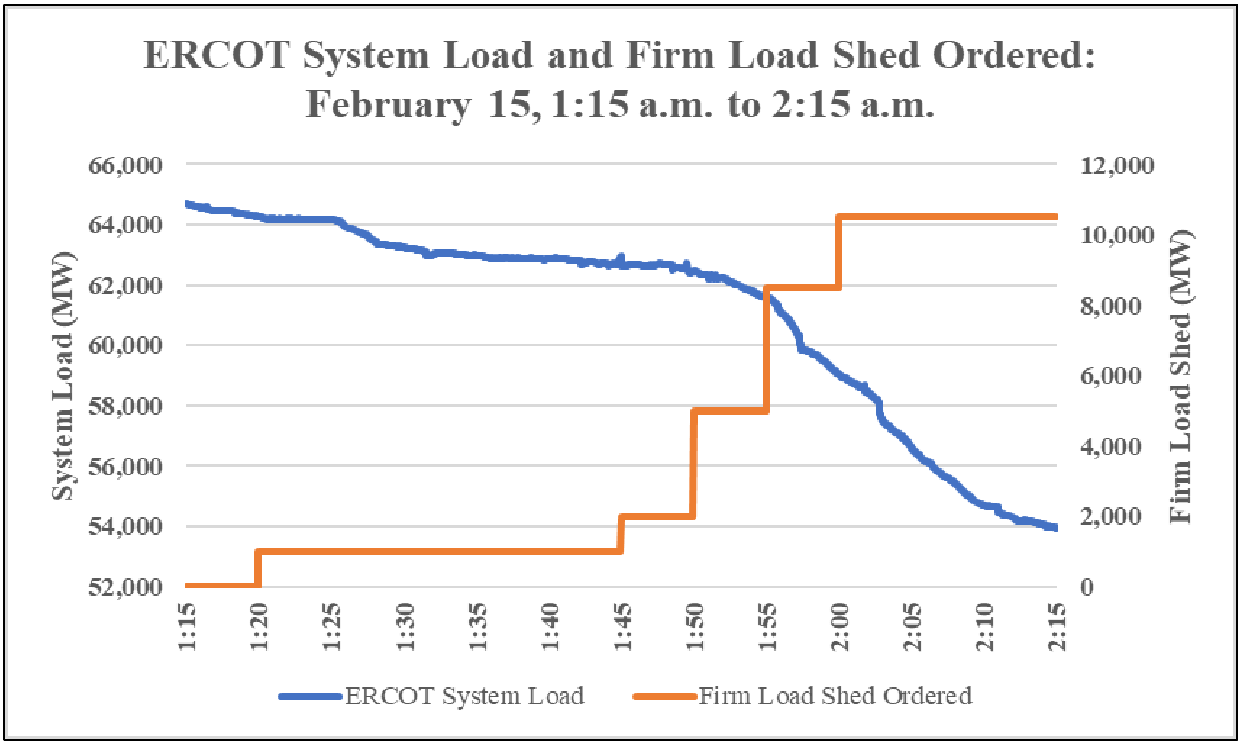


Figure 75: ERCOT Firm Load Shed and Changes in System Load, February 15, 1:15 - 2:15 a.m.



c. Transmission and Energy Emergencies in MISO and SPP

i. MISO South Transmission Emergencies

While ERCOT was experiencing energy emergency conditions early the morning of February 15, MISO South was also experiencing constrained transmission conditions due to significant increases in unplanned generation outages, as well as increasing load levels in both MISO South and southern SPP (shown in Figure 76, below). As a result, MISO system operators were required to declare a Local Transmission Emergency (LTE) for one of its load pockets in MISO South. To make up for generation shortfalls and increasing load levels, both MISO and SPP BAs scheduled power from BAs located in the eastern portion of the Eastern Interconnection that were not experiencing the extreme cold. These scheduled east-to-west imports increased east-to-west power flows into[213] and through MISO's transmission system, including through MISO South into southern SPP during the early morning hours of February 15 (shown in Figure 77, below).

[213] During the week of February 14, like SPP, MISO also needed to import power from BAs in the eastern portion of the Eastern Interconnection to alleviate generation shortfalls in its footprint.

Figure 76: MISO South and Southern Area of SPP

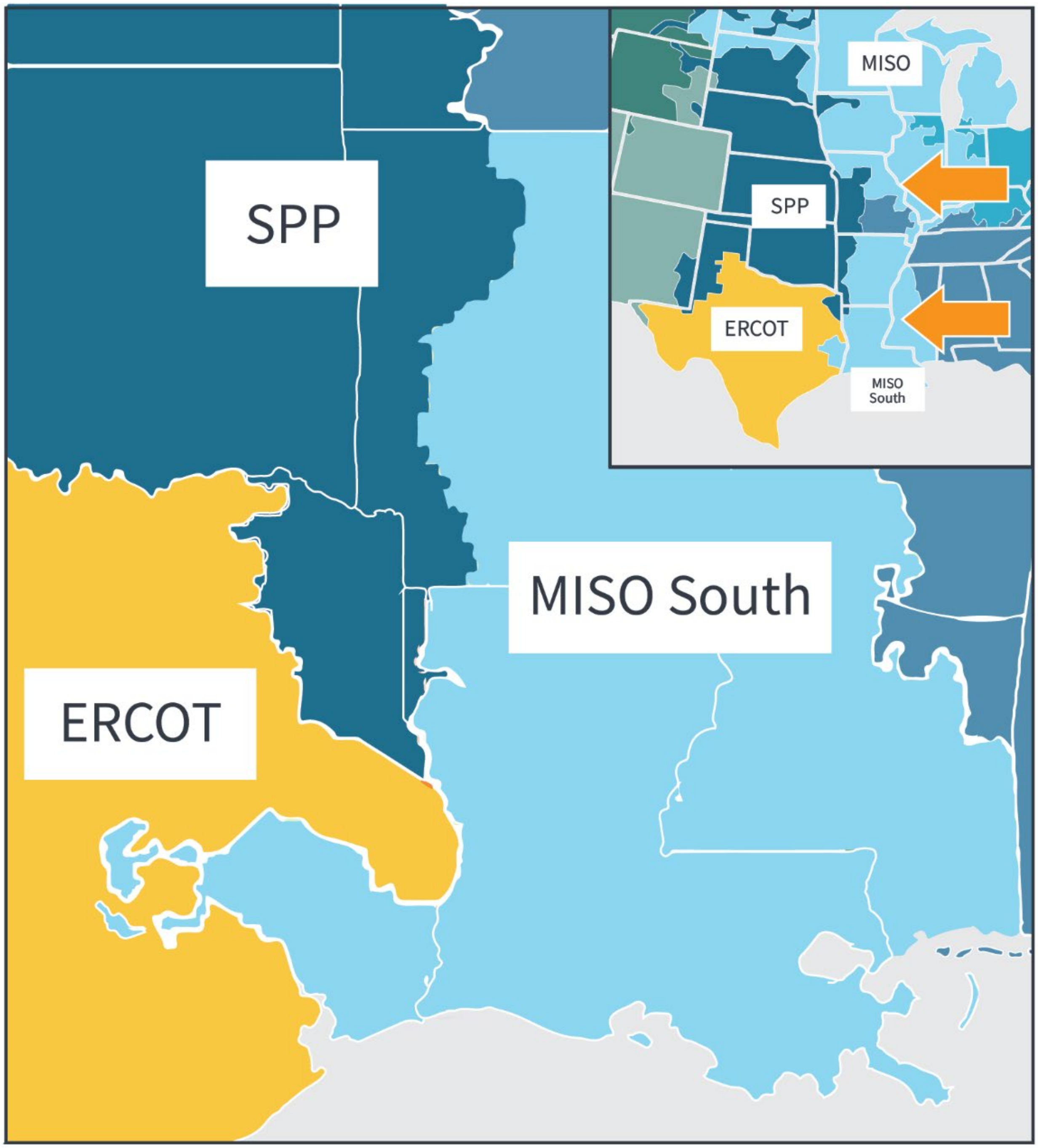
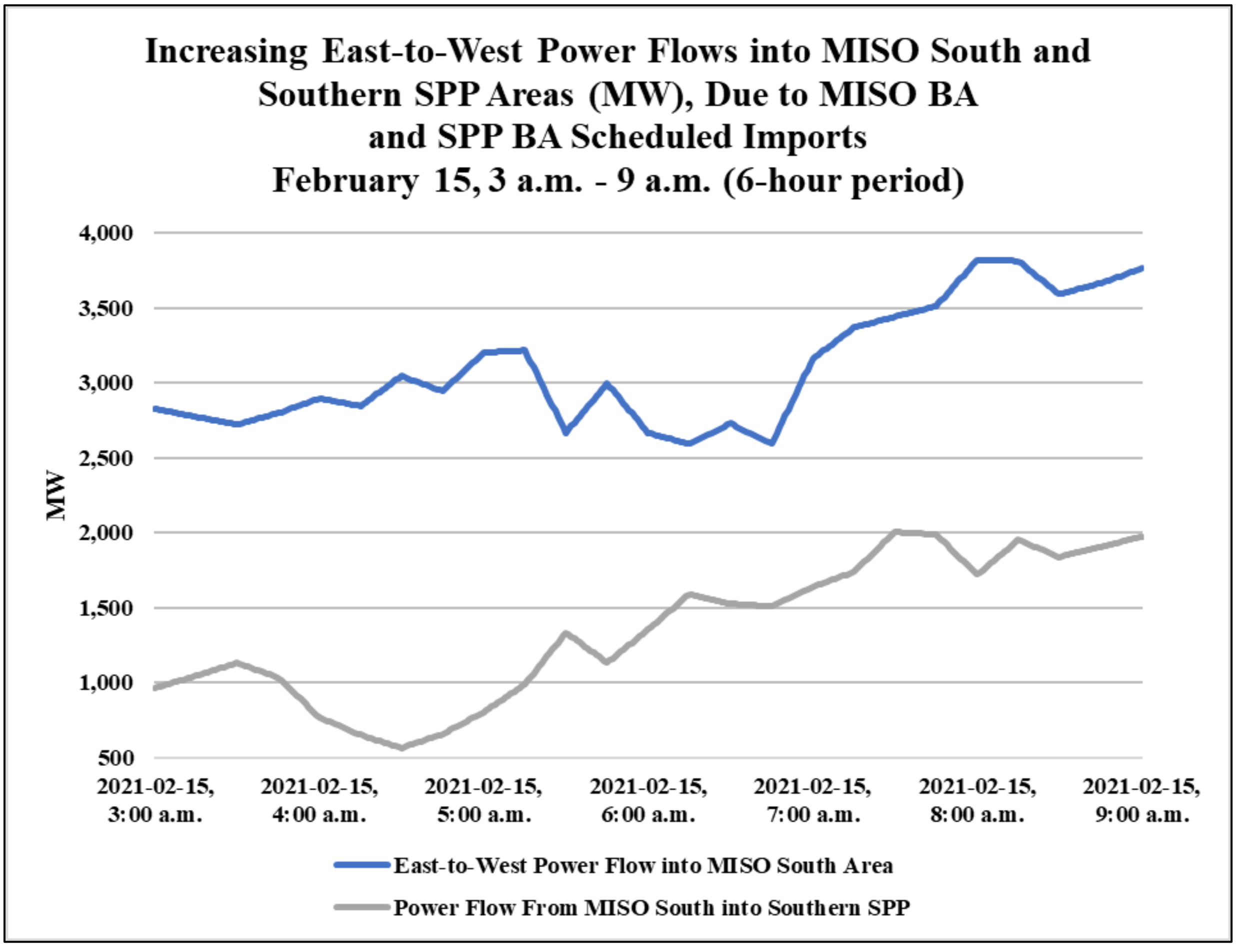


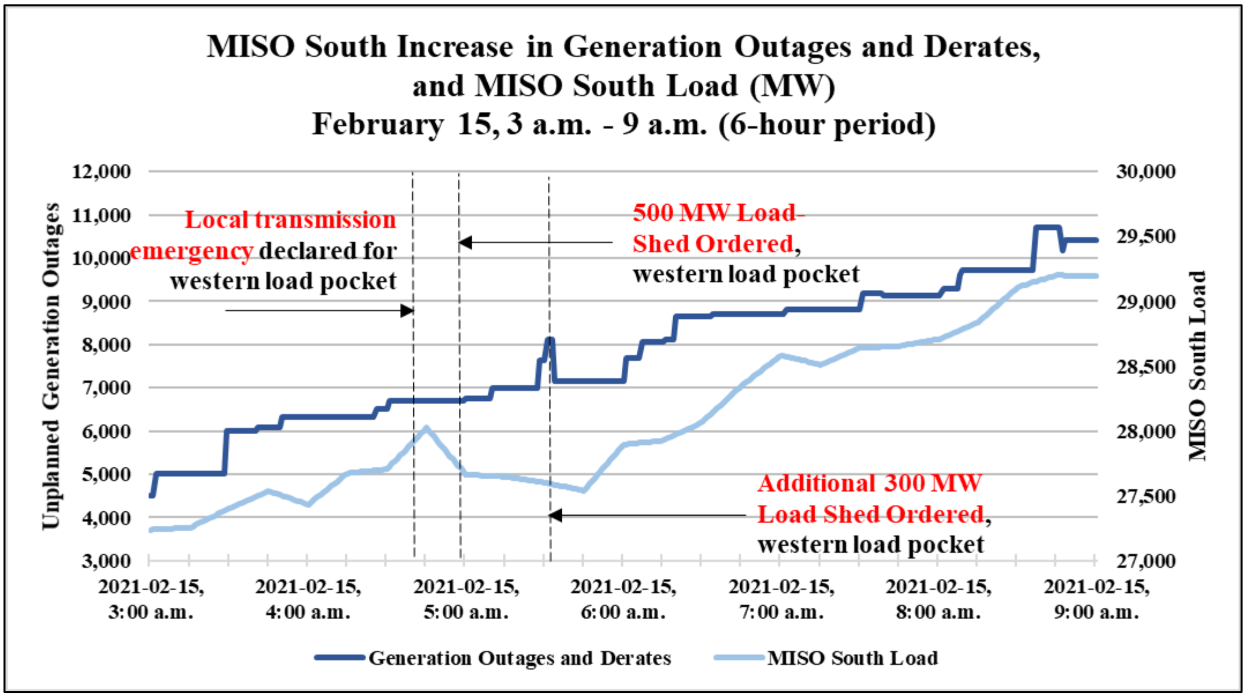
Figure 77: Increasing East-to-West Power Flows into MISO South and Southern SPP (MW), Due to MISO BA and SPP BA Scheduled Imports February 15, 3 a.m. - 9 a.m. (6-hour period)



At 5:15 a.m. on February 15, MISO issued a Local Transmission Emergency (LTE) for Entergy Arkansas to manually redispatch a nuclear unit to relieve a real-time overload of a 500 kV line, which was primarily due to key generation outages in an associated area of the SPP footprint.

In the early morning hours of February 15, conditions in the West of the Atchafalaya Basin, MISO South's western load pocket in eastern Texas, began to deteriorate. Two 230 kV transmission lines tripped due to icing conditions and MISO had over 1,400 MW of unplanned generation outages. After multiple transmission overloads (both pre- and post-contingency), at 4:40 a.m. on February 15, MISO declared an LTE and issued operating instructions to shed 500 MW of firm load in the western load pocket of MISO South at 4:55 a.m. At 5:33 a.m., as load continued to climb, MISO ordered an additional 300 MW of firm load shed (for a total of 800 MW) in the western load pocket. See Figure 78, below.

Figure 78: MISO South Increase in Generation Outages and Derates, February 15, 3 a.m. - 9 a.m. (6-hour period)



By 12:30 a.m. on February 16, most of the western load pocket load that had been shed was restored (700 of the 800 MW), based on off-peak system load levels and restoration of two transmission lines. But just a few hours later, both MISO South and SPP declared transmission emergencies. MISO had not only an LTE, but also a transmission system emergency (TSE), due to an Interconnection Reliability Operating Limit (IROL)[214] caused by additional generation outages in both MISO South and southern SPP.

At 4:30 a.m., MISO ordered an additional 300 MW of firm load shed due to a Local Transmission Emergency in the western load pocket, followed by a Transmission System Emergency in western Louisiana and the western load pocket in east Texas at 6:05 a.m., for which it ordered 500 MW of firm load shed. But because additional generating units tripped during implementation of the load shed, at 6:26 a.m., MISO ordered an additional 500 MW. MISO had ordered a total of 1,400 MW load shed in western Louisiana and the western load pocket, consisting of 1,000 MW in western Louisiana and 400 MW in the western load pocket (100 MW of which was preexisting from the

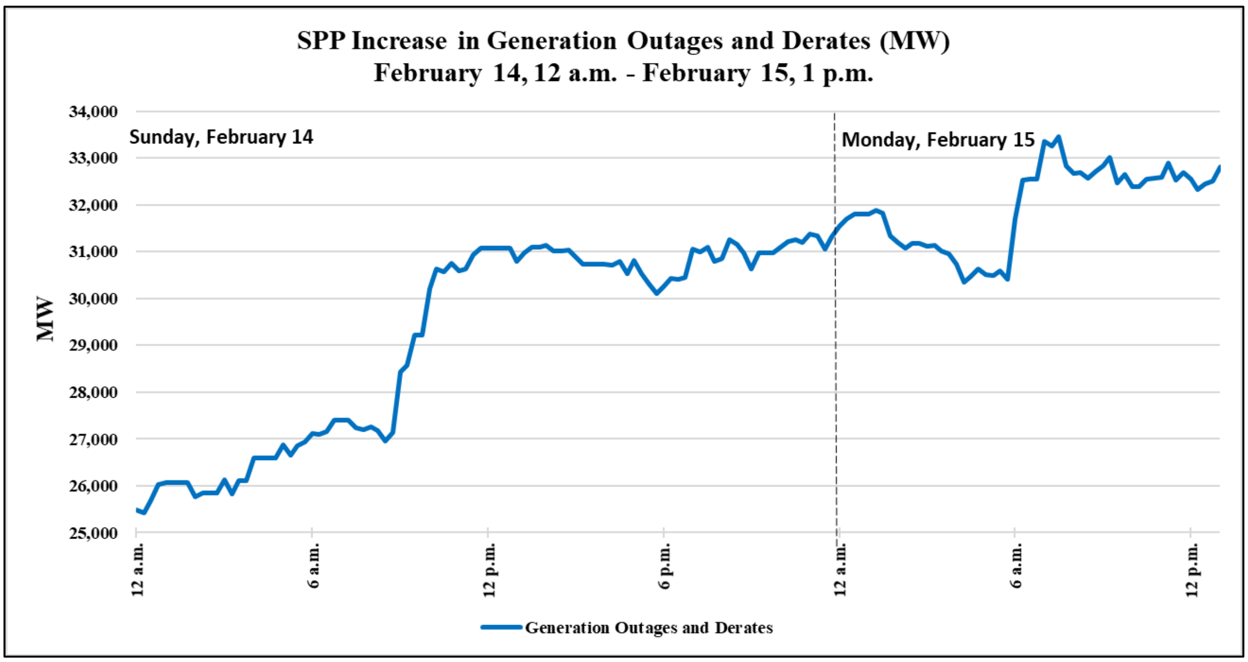
[214] An Interconnection Reliability Operating Limit is a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk-Electric System. A System Operating Limit is the most limiting of the values (whether MW, kV, MVAr, or Hz) for a specified system configuration to ensure that established reliability criteria are satisfied.

prior day). MISO began restoring load at 7:42 a.m. on February 16, had restored it all by 10:10 a.m. and terminated the TSE at 10:41 a.m.[215]

ii. SPP Energy Emergencies

While ERCOT and MISO both were experiencing emergency conditions during the early morning of February 15, SPP also declared an energy emergency when increasing unplanned generation outages and derates over the weekend combined with forecast peak electric demands (driven by extreme cold weather) for Monday, February 15. Unplanned generation outages were already increasing on Sunday, February 14, as shown in Figure 79, below, and the trend continued into Monday morning.

Figure 79: SPP Increase in Generation Outages and Derates (MW), February 14 12:00 a.m. – February 15, 1:00 p.m.



Based on its concerns about the weather and natural gas fuel supply issues, on Sunday February 14 at 9:27 a.m., SPP emailed its TOPs, GOPs, and market operators that an EEA 1 would begin Monday, February 15, at 5:00 a.m. Later that afternoon, at 1:57 p.m., SPP asked member utilities for the first time to make public appeals for energy conservation, beginning on February 15.

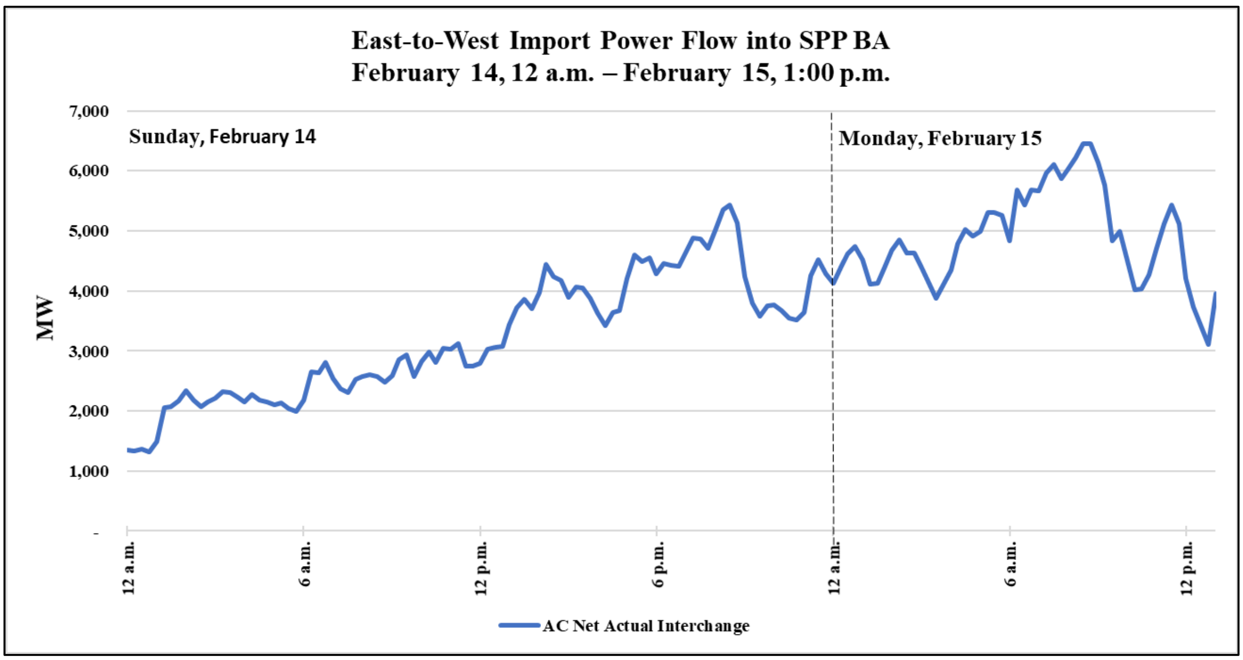
On Monday, February 15 at 5:00 a.m., SPP began its EEA 1, meaning that all available resources had been committed to meet obligations, and SPP was at risk of not meeting required operating reserves. From 6:00 a.m. to 8:00 a.m., unplanned generation outages and derates in the SPP footprint

215 At various times on February 15 and 16, MISO also declared EEA 2 for MISO South, which triggered appeals for voluntary load reduction and demand response, but not firm load shed.

increased over 3,000 MW, as shown in Figure 79, above. At 7:22 a.m., SPP declared an EEA 2, which required SPP to ask its member companies to issue public conservation appeals and served as a maximum emergency generation notification for generating units (informing that the emergency ranges of generating units may be required).

To meet its winter peak electricity demands and mitigate the energy emergency caused by increasing unplanned generation outages and derates, SPP began importing power from the east. SPP's imported power from entities in the eastern portion of the Eastern Interconnection flowed through MISO's transmission network (including MISO South, as shown in Figure 76, above) and was subject to curtailment.[216] Figure 80 below shows SPP's increasing trend of import power flows, ranging from 4,000 to over 6,000 MW early on February 15.[217]

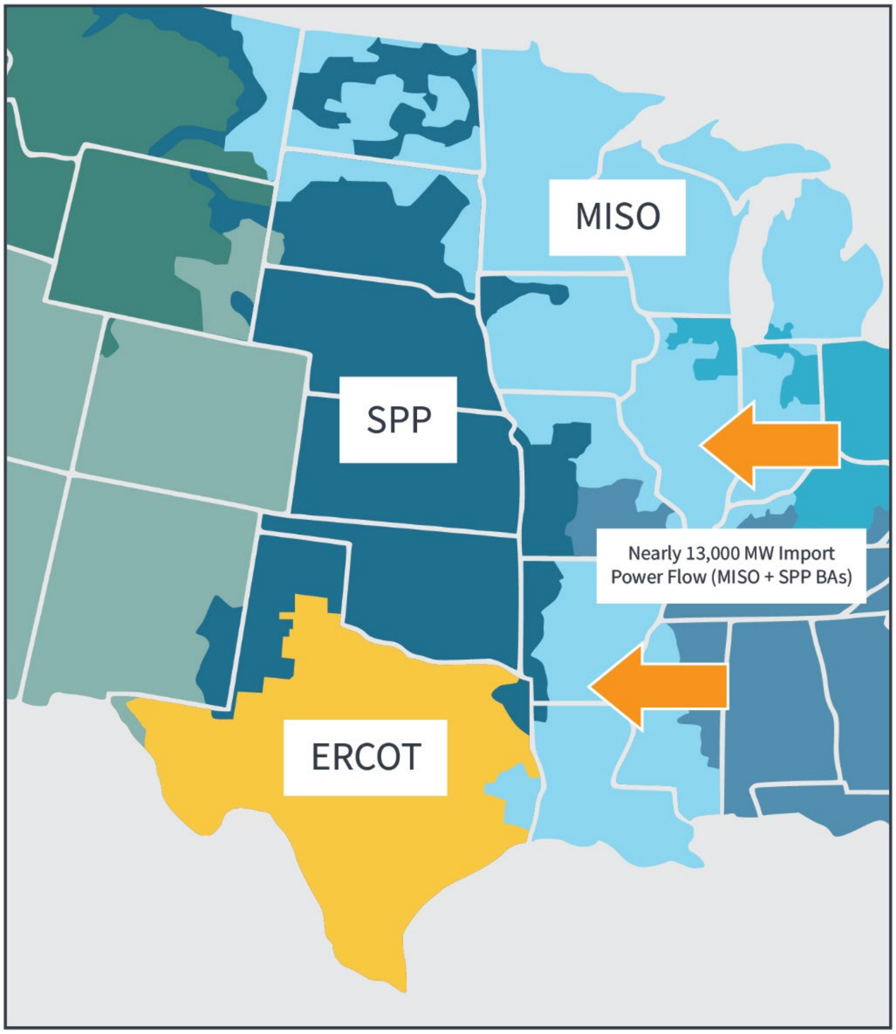
Figure 80: Increasing East-to-West Import Power Flows into SPP BA Footprint, Flowing Through MISO Transmission Network, February 14 – February 15, 1:00 p.m.



At the same time that SPP's imports from the east were increasing, MISO was also importing power from entities in the east, which, combined with SPP's imports, peaked at nearly 13,000 MW on Monday, February 15, as illustrated in Figure 81, below.

[216] SPP has DC ties with the ERCOT and Western Interconnections, but with much more limited transfer capabilities than it has with the BAs in the Eastern Interconnection.
[217] Compared to the east-to-west power imports SPP scheduled during the week of February 7, which generally remained below 4,000 MW (see Figure 43).

Figure 81: East-to-West Import Power Flows into MISO BA Footprint, February 15



Congestion due to the increasing imports continued building and at 4:17 a.m., MISO could have issued a TLR, however, because MISO operators knew of the emergency conditions in ERCOT and SPP, MISO RC did not immediately issue the TLR and curtail SPP's imports (which would also have curtailed ERCOT's imports). Instead, MISO RC and PJM worked in Safe Operating Mode, which allowed PJM to take some wind generating units offline to help mitigate congestion. This allowed MISO to delay issuing the TLR,[218] but at 7:30 a.m., MISO did issue a TLR 3B declaration to reduce non-firm flows into SPP, effective immediately, to relieve transmission constraints. SPP reached a maximum net import of 6,457 MW at 8:30 a.m., as seen on Figure 80, above, and still maintained

[218] This was another example of the RCs coordinating during the Event, working to prioritize the most critical emergencies among the three RCs.

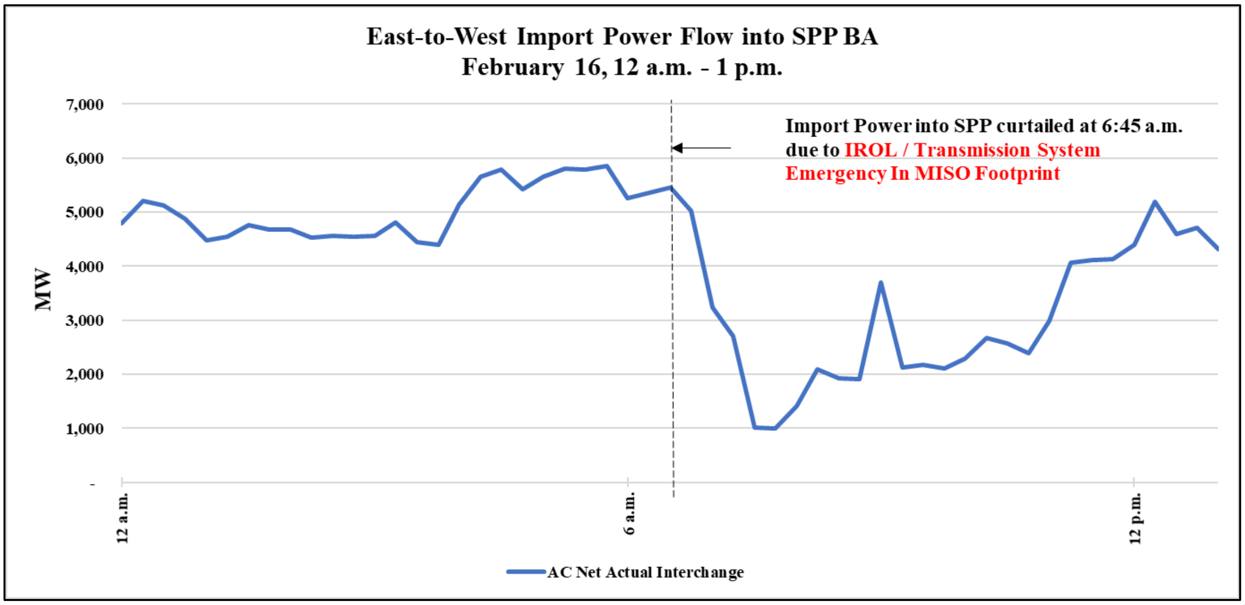
DC tie exports to ERCOT during this period. Shortly thereafter, at 8:58 a.m., SPP set an all-time winter peak load of 43,661 MW.

At 9:00 a.m., an unplanned outage of an additional 500 MW of generation occurred in the SPP footprint, and at the same time, SPP suffered additional TLR curtailments of non-firm imports to alleviate transmission constraints.[219] At 10:08 a.m. on February 15, with its imports reduced and insufficient reserves, SPP declared EEA 3. At 12:04 p.m. SPP directed 610 MW of firm load shed, and curtailed exports to ERCOT by 250 MW (from 815 MW to approximately 560 MW). SPP terminated the EEA 3 by 2:00 p.m., dropping to EEA 2 and restoring ERCOT's exports. SPP remained in EEA 2 through the rest of the day and into the morning of February 16.

Many system conditions remained the same in MISO and SPP on February 16: increased generating unit outages, peak electricity demands, and the need for high non-firm east-to-west power imports. At 6:00 a.m. on February 16, the MISO RC declared a TSE for its next-worst contingency (a 345kV transmission line, which was identified as a temporary IROL). Just minutes later, at 6:10 a.m., MISO lost the next-worst contingency, verified as an IROL by 6:18 a.m., and curtailed SPP's imports, by approximately 4,300 MW, via TLR 3B and TLR 5A declarations at 6:45 a.m. and 7:15 a.m., respectively (see Figure 82, below).[220] Still short of generation, and unable to import what it needed to compensate for the generation shortfalls, SPP declared its second EEA 3 of the Event at 6:15 a.m. due to "extremely low temperatures, inadequate supplies of natural gas and wind generation." At 6:44 a.m., SPP ordered 1,359 MW of firm load shed and curtailed 150 MW of firm exports to ERCOT. At 7:18 a.m., SPP ordered a second load shed block of 1,500 MW (1,359 firm load shed plus curtailed 150 MW of firm exports to ERCOT). SPP restored all load and exports by 10:07 a.m. and returned to EEA 2 at 11:30 a.m.

[219] TVA called a TLR Level 3 resulting in curtailments of non-firm power transfers from BAs east of MISO to SPP.
[220] Also, in addition to SPP import curtailments to help alleviate the IROL condition, at 6:52 a.m., MISO RC and a local TOP implemented 140 MW of firm load shed in MISO's own footprint to alleviate real-time and post-contingency transmission overloads.

Figure 82: East-to-West Import Power Flow into SPP BA Footprint, February 16, 12 a.m. – 1 p.m.



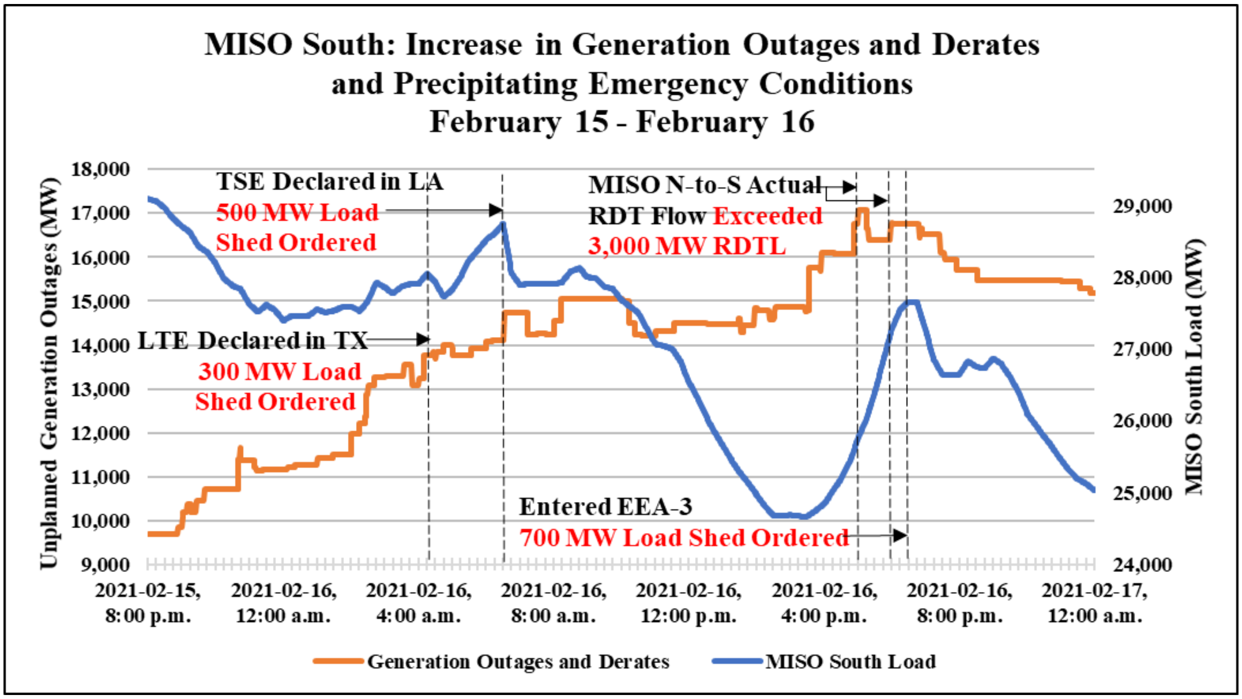
iii. SPP Transmission Emergency

On February 15 at 7:09 p.m., SPP RC declared a Transmission Emergency (which is on a system-wide level, not isolated to a single area, contingency, or event) due to multiple N-1 constraints across its system and abnormally high congestion throughout the SPP RC footprint. The Emergency lasted until February 16 at 4:22 p.m. SPP RC used market dispatch through Congestion Management Events, Out-of-Merit Energy dispatch instructions, reconfiguration plans and post-contingent load shed plans to mitigate the congestion across its footprint. SPP RC did not direct any load shed because of its transmission system emergency; however, one TOP did initiate load shed to help mitigate a local area pre-contingent facility rating exceedance on a 115 kV circuit. SPP RC posted its Transmission Emergency declaration on the RCIS, along with updates and notice of the transmission emergency declaration ending.

iv. MISO South Energy Emergency

During the early morning hours of February 15, the MISO South footprint experienced an increase of nearly 6,000 MW of generation outages, derates and failures to start from 3:00 a.m. to 9:00 a.m. Unfortunately, this pattern repeated beginning at approximately 8:00 p.m. on February 15 and continued until about 5:00 p.m. on February 16, as shown in Figure 83, below. During this time, MISO South lost an additional 7,300 MW of generation to outages, derates and failures to start. At its worst point, MISO South had over 16,800 MW of nameplate generation outaged (over 50 percent of MISO South's all-time actual winter peak load[221] and over 40 percent of its installed generation capacity).[222]

Figure 83: MISO South Continuing Unplanned Generation Outages and Precipitating Grid Emergency Conditions



Even though the cold temperatures across MISO South on February 16 were, on average, slightly less severe than on February 15, resulting in slightly lower electricity demands, MISO needed to declare transmission emergencies[223] and an energy emergency for MISO South due to the excessive unplanned generation outages, derates and failures to start. On February 16 at 4:59 a.m., MISO declared an EEA 2 for MISO South for the morning and afternoon, which would later be extended through the remainder of the day.

At 4:50 p.m. on February 16, the MISO South footprint suffered the additional outages of two large generating units, continuing the pattern of escalating unplanned generation outages. These events caused MISO's north-to-south actual (raw) RDT flow to exceed its RDTL of 3,000 MW, indicated in Figure 83, above. When MISO exceeded the RDTL, its operators contacted SPP and the other BAs that are parties to their joint operating agreement to discuss the conditions. While MISO's RDT flow returned within normal limits for a short time, at 5:50 p.m. MISO initiated a call to the

221 32.1 GW, January 17, 2018.
222 41.3 GW.
223 The LTE and TSE shown in Figure 83 above were previously described in sub-section (i) above.

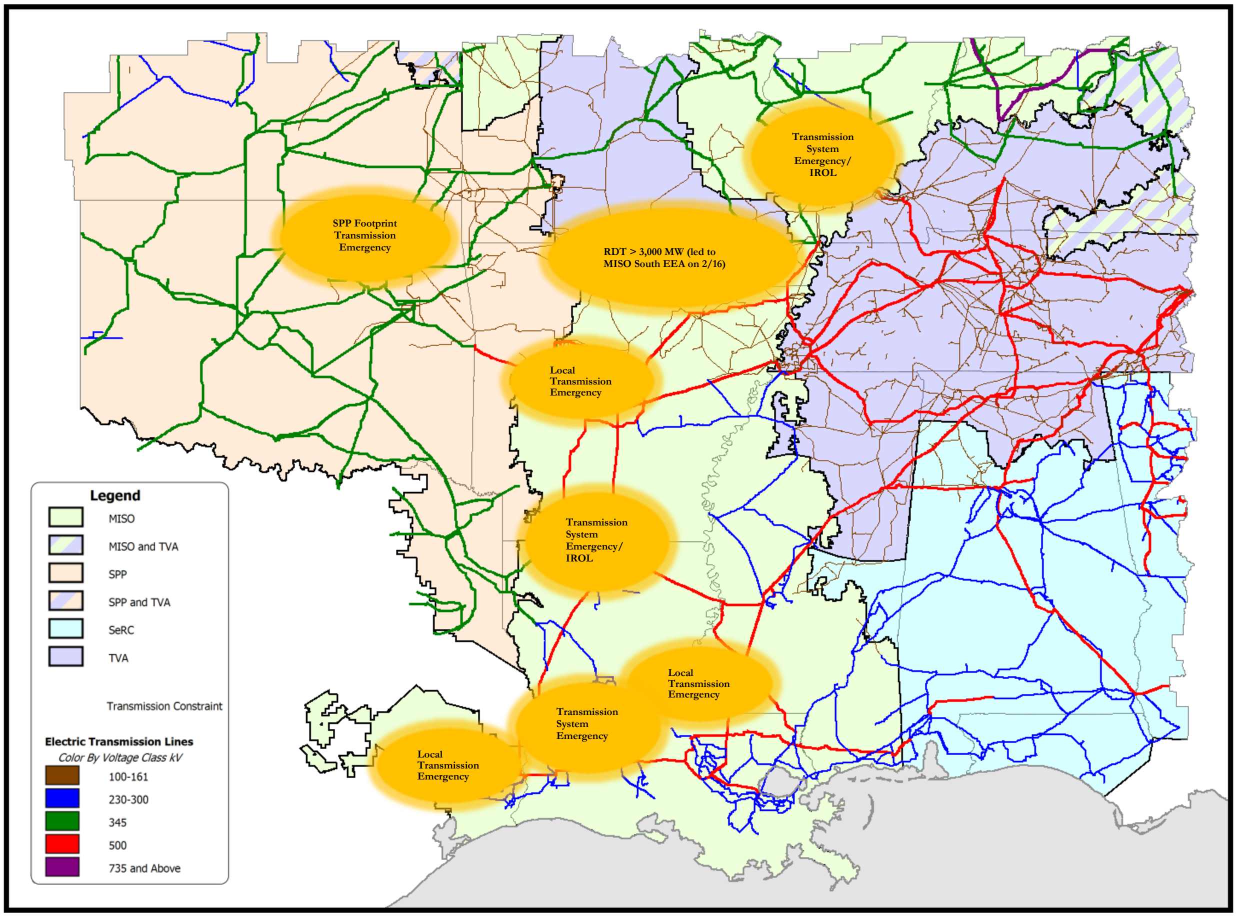
other BAs asking permission to raise the north-to-south RDTL to 3,700 MW.[224] The joint BA parties studied the potential, but with a portion of east-to-west import power transfers into MISO South already curtailed at 5:15 p.m., multiple 500 and 345kV post-contingency constraints developing on neighboring transmission systems, and the fact that granting the request would require additional curtailments to east-to-west import power transfers to MISO South, the BAs informed MISO at 6:10 p.m. that they were unable to facilitate the RDTL increase above 3,000 MW.

At 6:20 p.m. on February 16, MISO's actual north-to-south RDT flow again exceeded 3,000 MW due to both increasing generation outages and system demand, as shown in Figure 83, above. MISO had exhausted its ability to import power east-to-west into MISO South, its actual RDT flow north-to-south exceeded the RDTL, and it had no ability to raise the RDT limit without overloading neighboring transmission systems. Given all system conditions, including the inability to import the energy it needed to meet the MISO South demand, and realizing the grid's stability was in danger, at 6:40 p.m., MISO declared an EEA 3 and ordered 700 MW of firm load shed in MISO South to avoid widespread cascading outages.

At 7:00 p.m., the actual RDT flow dropped below the 3,000 MW RDTL. At 7:50, MISO ordered 300 MW of load that was shed to be restored, and at 8:41 p.m. ordered restoration of the remaining load, due to over 1,000 MW of generation returning to service and MISO South system demand decreasing following the evening peak. Figure 84, below, illustrates how constrained the Eastern Interconnection was in the MISO and SPP footprints, February 15-17, 2021.

[224] Under the version of MISO/SPP Regional Transfer Operations Procedure in effect during the Event, a party could request a temporary increase or decrease in the RDT limit to avoid a system emergency, or address emergent or actual system emergencies.

Figure 84: Summary: MISO and SPP Transmission Emergencies View – February 15 – February 17



d. Managing Firm Load Shed

From February 15 to 18, when winter electricity demands and unavailable generation were at their highest levels, to maintain electric grid reliability (including avoiding instability, uncontrolled separation or cascading failures of the BES), system operators for ERCOT, MISO and SPP BAs correctly implemented energy emergency measures including ordering firm load shed within their respective footprints as follows:

- ERCOT BA: starting on February 15, 2021 and lasting nearly three consecutive days and at its worst point, 20,000 MW;
- SPP BA: on February 15 and 16, four hours and twenty minutes total and at its worst point, 2,718 MW. SPP declared system-wide emergencies on February 15 and 16 due to capacity shortages within its BA. Most of SPP's unavailable generation was in the southern portion of its system. SPP shed 610 MW for one hour on February 15 when its imports were curtailed. On February 16, SPP shed load in two separate steps of 1,359 MW each (33 minutes apart), totaling 2,718 MW, for three hours (again the load shed coincided with imports being

curtailed to SPP). In both instances, SPP restored the lost load once curtailed imports were restored; and

- MISO BA (MISO South): on February 16 for two hours and forty-one minutes and at its worst point, 700 MW.

The following Figures 85 – 87 show the patterns of EEA 3 firm load shed ordered for energy emergencies from February 15 through February 18 in ERCOT, SPP and MISO, respectively.

Figure 85: ERCOT EEA 3 Energy Emergency Firm Load Shed Ordered (MW)

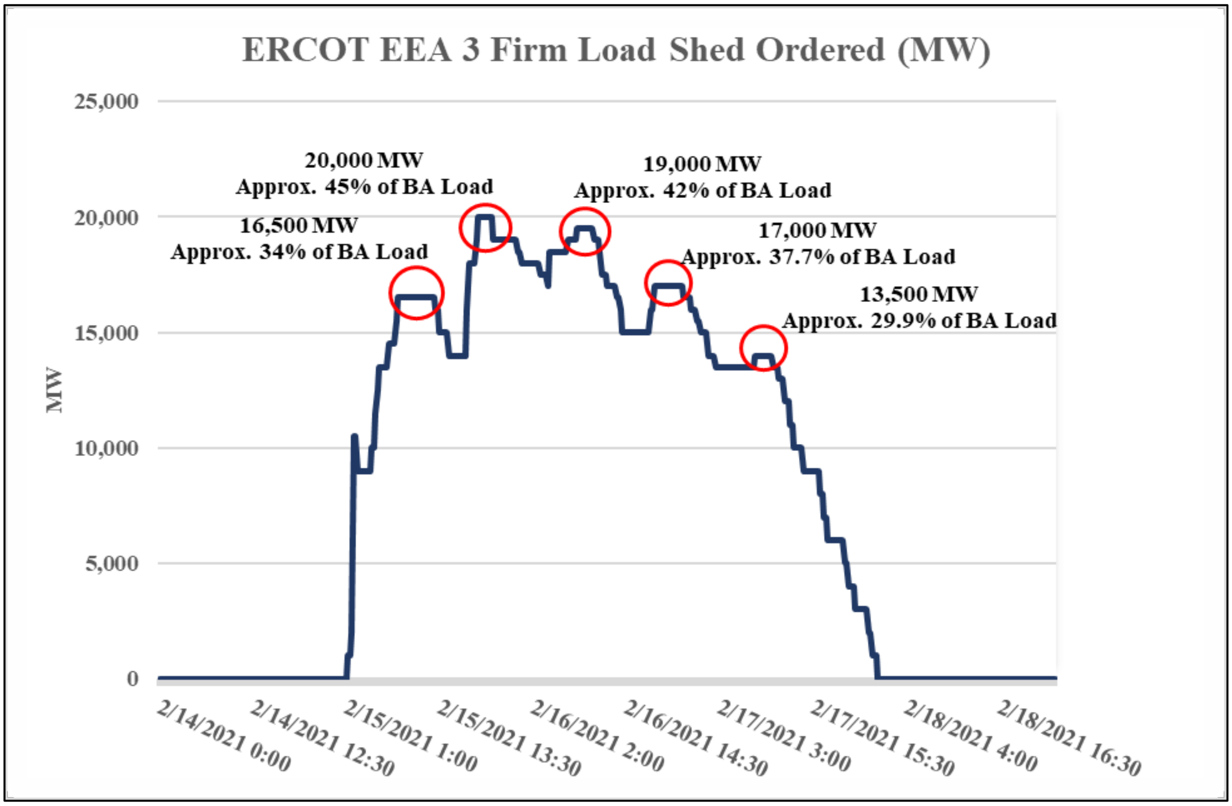


Figure 86: SPP EEA 3 Energy Emergency Firm Load Shed Ordered (MW)

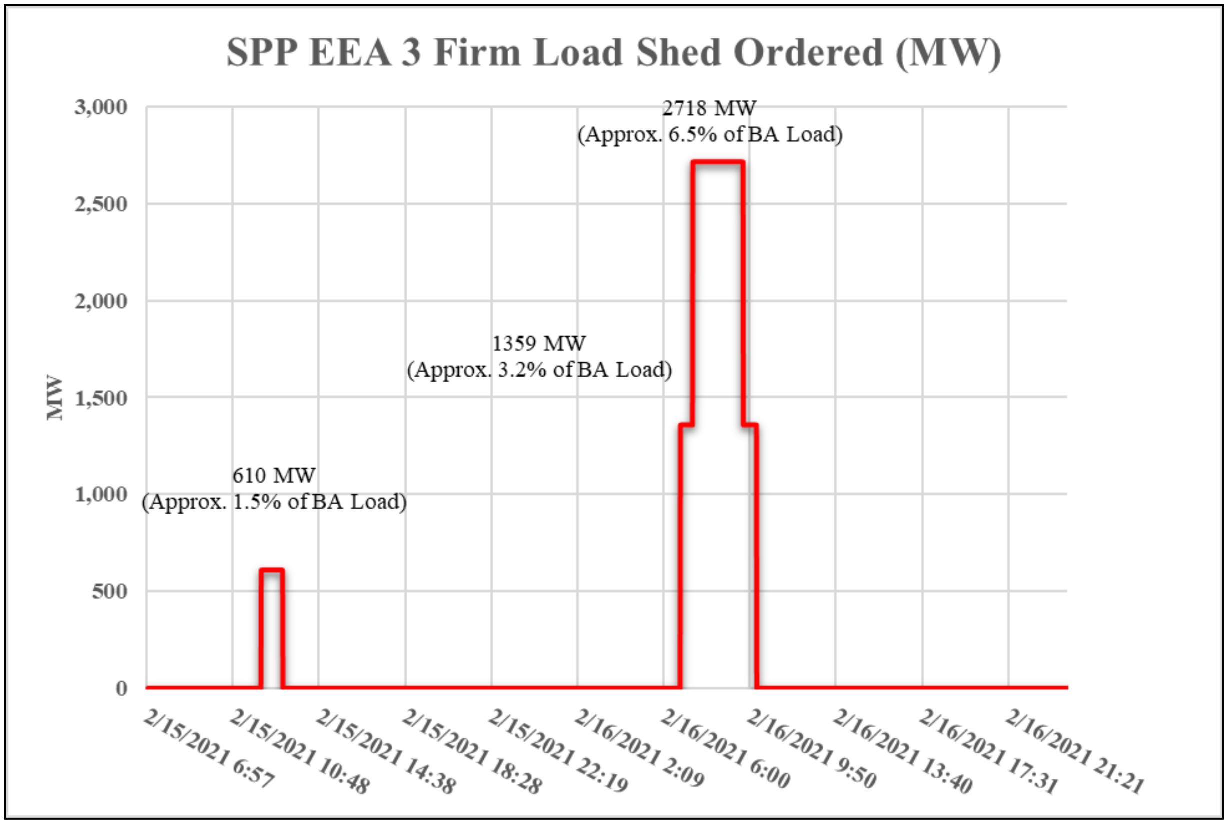
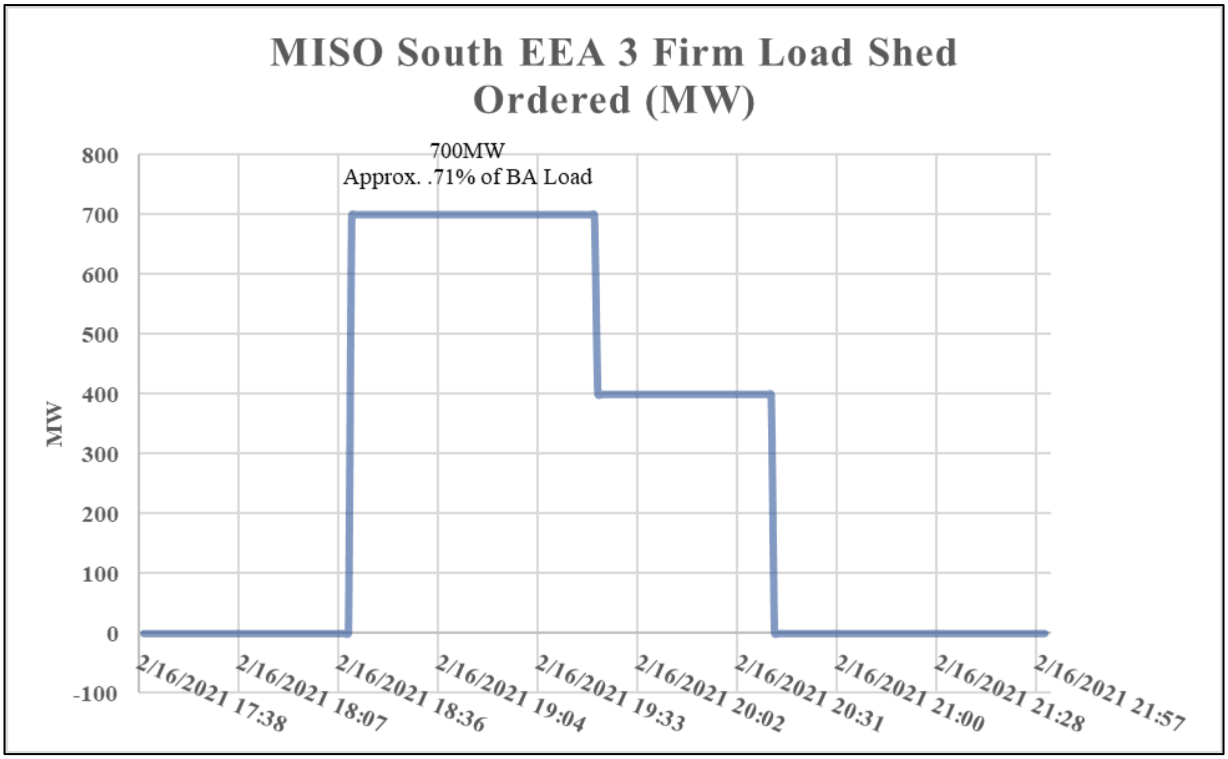


Figure 87: MISO South EEA 3 Energy Emergency Firm Load Shed Ordered (MW)



i. Natural Gas – Electric Interdependency: Firm Load Shed Caused Outages to Natural Gas Facilities Critical to Providing Natural Gas Fuel Supply to BES Generating Units

The manual load shed plans (of TOPs) and automatic underfrequency load shed plans (of TOs and DPs) within the ERCOT footprint were designed to avoid controlled power outages to priority or critical electric loads if the need to shed firm load arose. However, most of the natural gas production and processing facilities the Team surveyed were not identified as critical load or otherwise protected from manual load shedding. Because it is not the entity that implements load shedding, ERCOT did not anticipate that firm load shed would contribute to power outages of natural gas production and processing facilities, that would in turn, contribute to the decline in natural gas supply and delivery to natural gas-fired generating units. Thus, from early February 15 through February 18, the implementation of manual firm load shed by ERCOT, SPP and MISO[225] operators to preserve BES reliability partially contributed to the decline in the production of natural

[225] Even though SPP's orders for firm load shed were on a much smaller scale than ERCOT's, circuits providing natural gas fuel supply to generating units, including facilities in Texas, were known to be interrupted. Some TOPs within MISO did not exclude natural gas infrastructure from their manual load shed plans; therefore, MISO South manual load shed could also have partially contributed to the decline in the production of natural gas.

gas. Because many critical natural gas infrastructure loads had not been identified during the Event, and both power outages caused by both weather and firm load shed were coincident during this timeframe, the extent of power outages to critical natural gas infrastructure loads due to firm load shed is unknown.

Within the SPP footprint, some natural gas infrastructure was identified as critical and protected from load shed, while other circuits supplying natural gas infrastructure were not protected from manual load shed. One TOP with rural load that includes a significant amount of oil and natural gas wells stated that some wells were impacted by its load shed, but it did not receive any inquiries or concerns about load shed affecting natural gas infrastructure. Two TOPs within SPP's footprint reported they reached out to natural gas infrastructure entities during the Event and either did not shed their load or ensured that load shed would not impact their operations by verifying that the natural gas infrastructure entities had onsite generation. Another TOP reported that while natural gas infrastructure was not designated as critical at the time of the Event, it was now working with natural gas infrastructure entities to identify natural gas infrastructure necessary to support generating units.

ii. Difficulties in Rotating Firm Load Shed and Avoiding Overlap of Automatic Load Shed/UFLS

As February 15 wore on, due to increasing levels of unplanned generating unit outages and derates and increasing electricity demands, ERCOT needed to shed larger quantities of firm load to keep the power grid stable. The combined magnitude and duration of manual firm load shed needed to maintain BES reliability in ERCOT caused electric service providers (TOPs, TOs and DPs) to have difficulties in rotating the manual load shed and required operators to implement controlled outages of electric circuits normally reserved for automatic load shed (e.g., underfrequency load shed/UFLS). In ERCOT, at least 25 percent of the load is to be reserved for automatic load shedding (and this does not include critical loads protected from manual load shedding, such as hospitals, police stations, etc.). System operators are required to minimize overlap between manual load shed and UFLS.[226] ERCOT operators needed to protect at least 25 percent of load beyond the 14-28 percent of manual load shed ordered on February 15-16 and the identified critical loads from manual load shed. These protective actions made it difficult for ERCOT operators to avoid use of some UFLS circuits for manual load shed and hampered their ability to use additional circuits to perform rotational load shed. The use of the UFLS circuits for manual load shed would render them unavailable if the frequency in ERCOT dropped and UFLS was needed to preserve BES reliability.

[226] See Reliability Standard EOP-011-1 - Emergency Operations, Requirement R1.

e. Conditions Gradually Improve

i. MISO South and SPP

The last of SPP's and MISO's energy emergency EEA 3 firm load shed events occurred on February 16. While Wednesday through Friday, February 17 to 19 brought less severe cold weather conditions as compared to February 15 to 16, below-freezing temperatures still prevailed in southern SPP and MISO South locations for many hours. Both still had significant unplanned generating unit outages in their respective footprints, due to ongoing freezing and natural gas fuel supply issues.

MISO South. At the start of February 17, MISO's north-to-south actual RDT flow again exceeded its RDTL of 3,000 MW, due to MISO South's increased unplanned generation outages, electricity demands and east-west import constraints. At 12:54 a.m. on February 17, MISO declared a TSE due to an emerging next-contingency IROL condition. Under the emergency, MISO was able to manage generation resources to reduce actual RDT flows to be within limits, and the TSE was converted to an LTE, which was subsequently terminated at 8:40 a.m. For its evening peak load timeframe on Wednesday, February 17, MISO declared another energy emergency (EEA 2) for MISO South and called on voluntary load management measures. MISO terminated the EEA 2 at 8:30 p.m. and did not need to implement energy emergency load reduction measures for the remainder of the week. MISO's last LTE for Louisiana was terminated on February 18 at 12:00 p.m. On Saturday, February 20, MISO ceased conservative operations and returned to normal operations at 3:00 pm.

SPP. By Wednesday, February 17 at 1:15 p.m., SPP was able to downgrade its energy emergency to EEA 1. Like MISO for MISO South, for its evening peak load timeframe on February 17, SPP escalated its energy emergency to EEA 2 for its footprint, and instructed voluntary load management measures again to be implemented until 10:59 p.m., when it downgraded its energy emergency level to EEA 1. On February 19 at 9:20 a.m., SPP was able to cease energy emergency operating conditions. SPP remained in conservative operations until Saturday, February 20, when it returned to normal operations at 10:00 pm.

ii. ERCOT

With ERCOT's generation shortfalls much more severe than MISO South and SPP footprints, it remained in EEA 3 on February 17. Moderating temperatures allowed gradual reductions in firm load shed, even though only a small number of generating units had returned to service at that point. As evening approached, additional generation that returned to service was sufficient to reduce load shed directives through the evening of February 17, and by 11:55 p.m., ERCOT issued instructions to restore all remaining load, for the first time since Monday, February 15.

On Thursday, February 18, unplanned generation outages in the ERCOT footprint continued to return to service as temperatures continued to increase. Some customer outages remained, due to ice storm damage or need for manual restoration and return of large industrial facilities. On Friday, February 19, at 9:00 a.m., ERCOT downgraded its energy emergency to EEA 2, and by 10:35 a.m., ERCOT returned to normal operations, concluding the Event.

D. Post-Event Actions by Entities & Government

1. By Involved Entities

On July 13, 2021, ERCOT delivered its "Roadmap to Improving Grid Reliability," a list of sixty actions, each of which is marked "complete," "on track," or "limited progress."[227] Approximately half of the actions related directly to reliability, while others involved communications, governance, or market issues. Some of the completed actions addressed inquiry recommendations areas, such as generators providing more frequent market updates or reporting all forced outages, and improving the assessment of extreme weather scenarios.[228] Among the actions that are on track include identifying when ERCOT load forecasts have high uncertainty, considering whether additional reserves are necessary, improving the reliability of black start, improving fuel security via market incentives, and considering on-site fuel supply for generating units.[229] ERCOT [230] is developing new load forecast metrics that will be completed in 2021.

MISO and SPP released public reports on the Event.[231] In addition to analyzing the grid operations, markets, communications, and other key aspects of the events experienced in their respective footprints, both made recommendations. MISO identified 20 lessons learned, joining each lesson with one or more "actions to address." SPP made 22 recommendations (for new actions, policies, or assessments) organized into 3 tiers by urgency.

As with ERCOT's Roadmap, some of the recommendations involved communications, markets, and other non-reliability topics. Other recommendations covered important reliability topics including resource adequacy, fuel assurance, planning for extreme event scenarios and load reduction, emergency drills, situational analysis, system operator training, and protection of critical infrastructure.[232]

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[227] Electric Reliability Council of Texas (ERCOT), *Roadmap to Improving Grid Reliability*, (July 13, 2021), http://www.ercot.com/content/wcm/lists/219694/ERCOT_Roadmap_Final_July_13_2021.pdf.
[228] See Actions 3, 4, and 9.
[229] See Actions 22, 37, 56, and 57.
[230] ERCOT Nodal Protocol Revision Request Number 1089 (July 28, 2021) Nodal Protocol Revision Request (NPRR) 1089 (previously, ERCOT only required an official with binding authority to submit the information, not the highest-ranking official).
[231] Midcontinent Independent System Operator (MISO), *The February Artic Event: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative*, (Feb. 14-18, 2021), https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf; A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations (July 19, 2021) https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf.
[232] See Appendix H for a comparison of recommendations from several reports on the Event, including the ERCOT, MISO and SPP reports.

2. By Government

Texas Senate Bill 3 (SB3) was the most significant legislation that arose out of the Event. Effective on signing on June 8, 2021, SB3 combined provisions regarding public communication during emergencies, gas-electric coordination, protecting critical gas infrastructure, additional inspections of, and reports regarding, winter preparedness, and load shedding. Among the provisions most relevant to the Event are:

- Development of a new "power outage alert" (with coordination among several agencies including the PUCT and Department of Transportation (to use its highway messaging signs).
- Creation of a new "Texas Energy Reliability Council," with the purpose of fostering better communication between the natural gas and electric industries. Its members include the Chairs of the Texas Railroad Commission and PUCT, ERCOT, and members from the natural gas and electric industries, as well as other energy and industrial sectors.
- Creation of a committee to map the electricity supply chain "in order to designate priority electricity service needs during extreme weather events" (and update that map yearly). The committee is also required to file reports with the Legislature on the "reliability and stability of the electricity supply chain," and "include recommendations to . . . decrease the frequency of extended power outages caused by a disaster." The committee, composed of Executive Directors of the PUCT and the RRC and the President and CEO of ERCOT, is tasked with mapping Texas's electricity supply chain, identifying critical infrastructure sources, and establishing best practices to prepare facilities in the supply chain to maintain service in an extreme weather event, among other responsibilities.
- Requiring gas supply chain facilities identified on the electricity supply chain map and directly serving natural gas-fired generating units to "implement measures to prepare to operate during a weather emergency," be subject to inspections (prioritized based on risk level), and if repeatedly experiencing weather-related interruptions, to obtain an independent assessment of their weatherization plans, procedures and operations and submit the assessment to the RRC. The RRC can require a gas supply chain facility to implement recommendations from the independent assessment.
- Development of a communication system between critical infrastructure sources, the PUCT and ERCOT to ensure that electricity and natural gas supplies in the electricity supply chain are prioritized to those sources during an extreme weather event.
- Requiring the PUCT and RRC to collaborate on rules for designating natural gas facilities and entities as critical electric customers or critical gas suppliers, which could include natural gas production, processing, and transportation, related water disposal facilities, and delivery

of natural gas to generating units[233], and requiring that only facilities prepared to operate during a weather emergency may be designated as critical.

- Requiring municipal utilities, cooperatives, power generation companies or exempt wholesale generators to implement measures to prepare their generating units to provide "adequate electric generation service during a weather emergency," be subject to inspections, and if repeatedly experiencing weather-related interruptions, to obtain independent assessment of their weatherization plans, procedures and operations, and submit the assessment to the PUCT. The PUCT can require the generation provider to implement recommendations from the assessment.
- Requiring that utilities provide retail customers with information about involuntary load shedding, and how to apply to become a critical care retail customer or other protected class of retail customer.
- Adding new rules regarding how to conduct firm load shedding, including that the PUCT examine whether entities complied with their load shed plans, and providing for at least one load shed drill each in the summer and winter.
- Requiring procurement of competitive "ancillary or reliability services" to ensure reliability during extreme heat and extreme cold weather and during times of low wind or solar; winter resources required to include on-site fuel storage, dual-fuel capability or "fuel supply arrangements to ensure winter performance for several days."

On October 21, 2021, the PUCT issued a final rule requiring generating units in ERCOT to take certain winter preparation actions by December 1, 2021, including:

- Using best efforts to implement measures intended to ensure sustained operation of "cold weather critical components[234] during winter weather conditions, including weatherization, onsite fuel security, staffing plans, operational readiness, and structural preparations . . .;"
- Take specific preparation measures including installing adequate wind breaks, enclosing sensors for cold weather critical components, inspecting/repairing thermal insulation, confirming the operability of instrument air moisture prevention systems, maintaining and testing (on a monthly basis, November through March) freeze protection components, and installing monitoring systems for cold weather critical components (e.g., heat tracing or instrument air moisture prevention systems);

[233] The RRC also revised the form for "Application for Critical Load Serving Electric Generation and Cogeneration," revised as of March 2021. Instead of stating that it does not apply to "field services," which could have deterred production facilities from seeking protection, no matter how large or critical the facility, the form now more broadly covers production, processing and pipeline facilities: "[t]he designation shall only be requested for individual premises (meters) that provide electricity to natural gas production, saltwater disposal wells, processing, storage, or transportation such as a natural gas compressor station, gas control center, or other pipeline transportation infrastructure."

[234] Similar to the Report, the PUCT defines cold weather critical component as "any component that is susceptible to freezing or icing, the occurrence of which is likely to significantly hinder the ability of a resource or transmission system to function as intended and, for a generation entity, to lead to a trip, derate or failure to start . . .." *Rulemaking to Establish Electric Weatherization Standards*, Project No. 51840, Order Approving Rule, at p. 86, definition 1 (Oct. 21, 2021); 51840_101_1160359.PDF (texas.gov).

- Use best efforts to address cold weather critical component failures that occurred "because of winter weather conditions in the period between November 30, 2020 and March 1, 2021;"
- Provide training on winter weather preparations and operations; and
- "Determine minimum design temperature or minimum experienced operating temperature, and other operating limitations based on temperature, precipitation, humidity, wind speed, and wind direction."[235]

[235] *Id.* at 86-89.

IV. Analysis

A. Overview

The Event began with extreme cold temperatures and freezing precipitation. Both open-frame generating units, common throughout Texas and the South Central U.S., and natural gas production infrastructure, with its associated water, are known to be vulnerable to freezing. In addition, wind turbines are known to be vulnerable to blade icing because of freezing precipitation. The extent to which the Event was caused by the failure of all types of generating units to prepare for extreme cold weather or associated freezing precipitation, cannot be overstated. Figure 88, below, illustrates the generating unit outages by fuel type over time over the course of the Event. Outages of wind generating units rose early in the Event, starting February 10, and reached a plateau of 20 to 25 GW that sustained through February 18. Natural gas and coal generating unit outages rose on February 15, with natural gas-fired generating unit outages nearly doubling in two days, from 25 GW to 50 GW by February 17. Figures 89 through 91 show the relative proportions of the fuel types of the generating units that experienced unplanned outages, derates and failures to start during the Event, analyzed by total MW loss during the Event, number of outages, or number of units.

Figure 88: Generation Outages, Derates, and Failures to Start (MW) by Fuel Type, February 8-20, Total Event Area

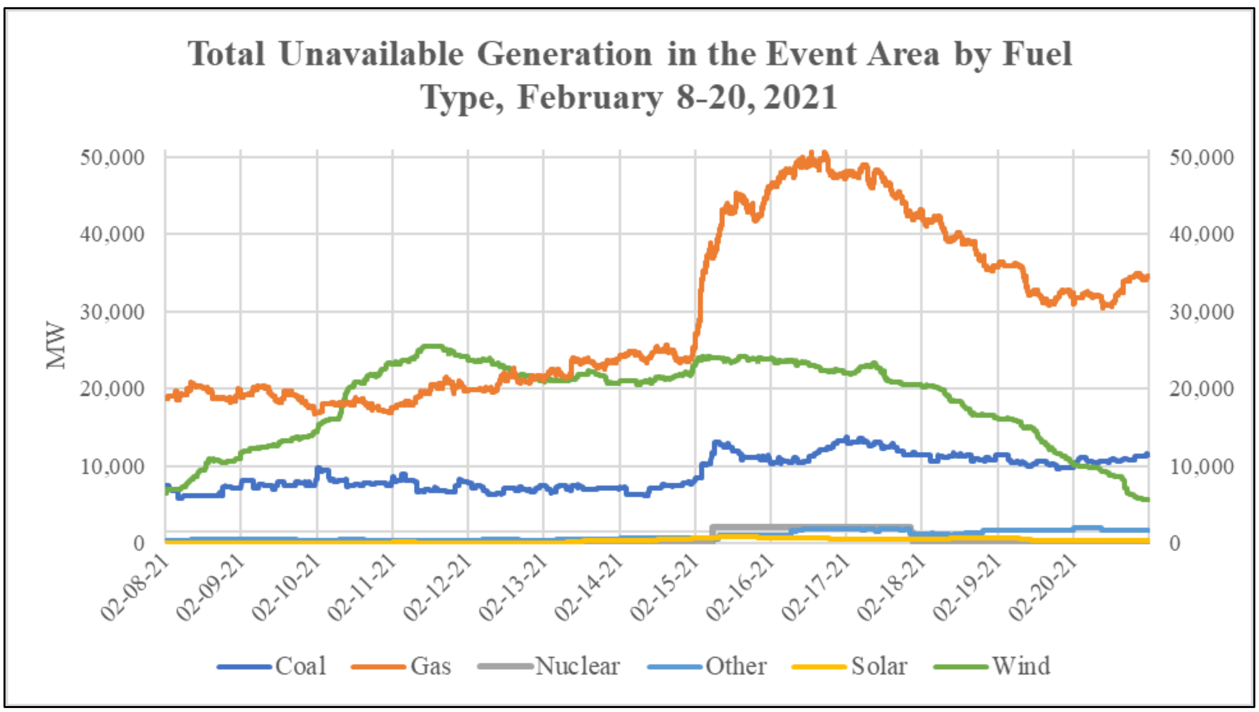


Figure 89: Number of Incremental Unplanned Generation Outages, Derates, and Failures to Start by Fuel Type, February 8-20, Total Event Area

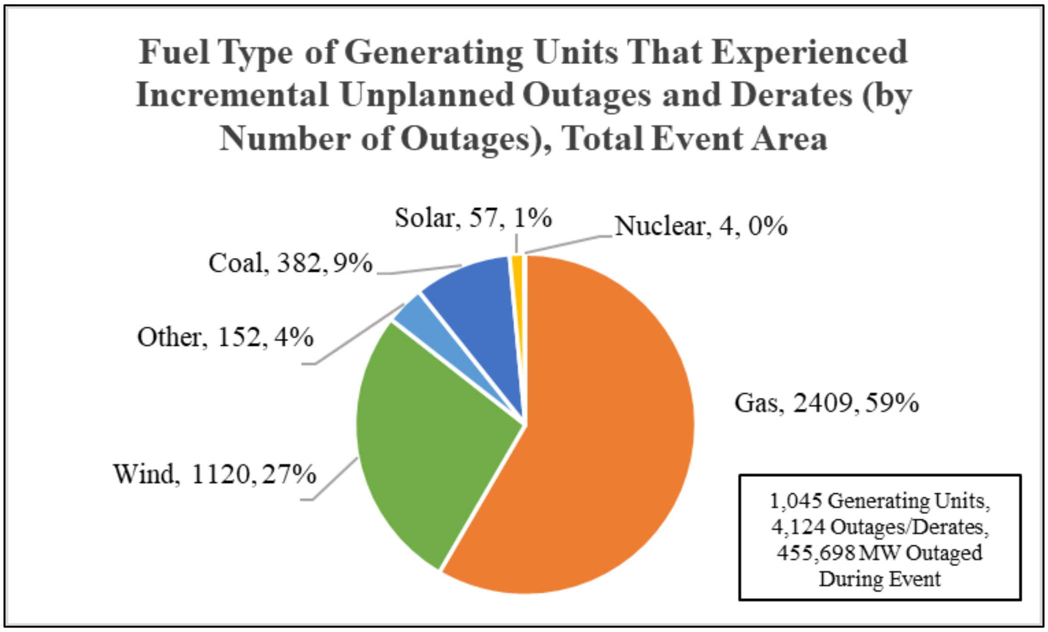


Figure 90: Generation Outages, Derates, and Failures to Start (Outaged MW) by Fuel Type, February 8-20, Total Event Area

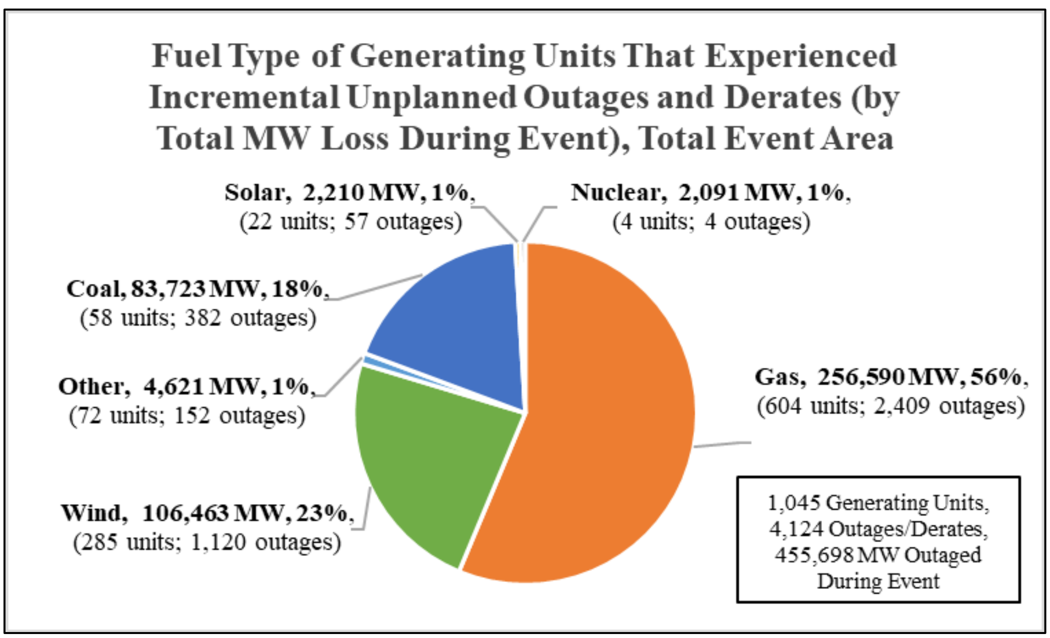
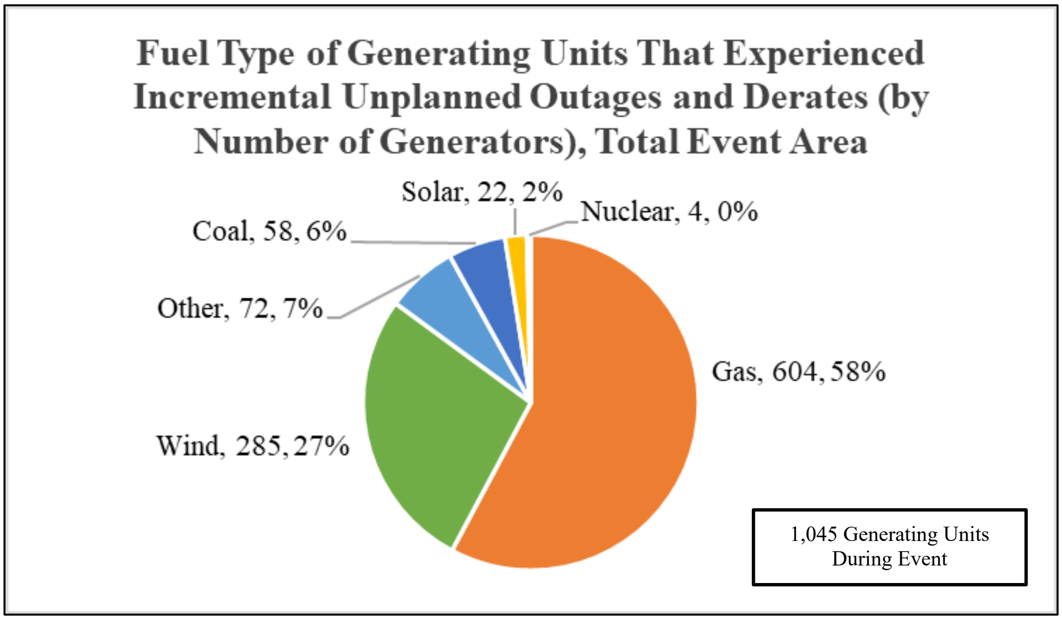


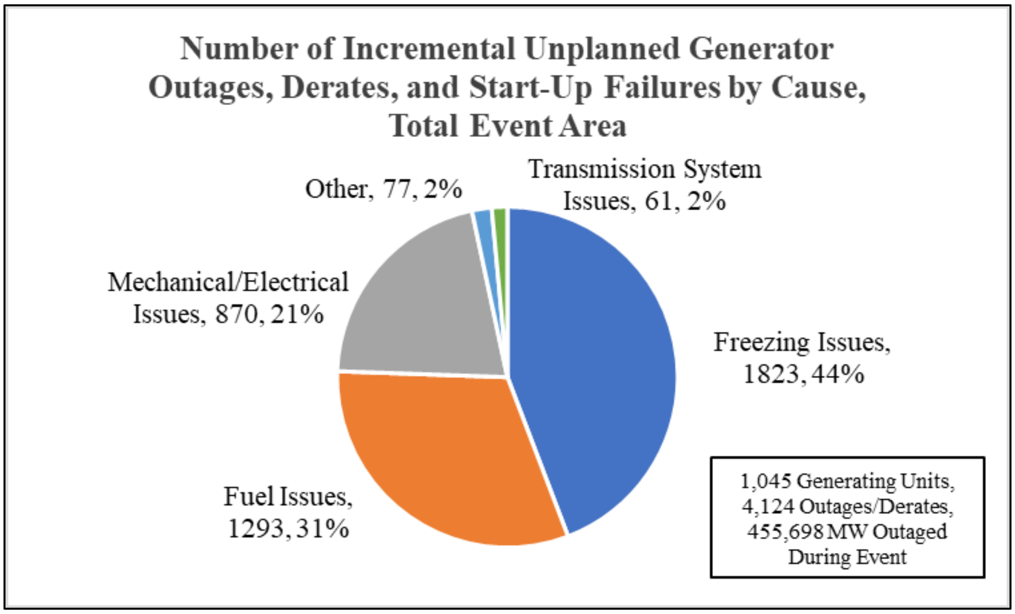
Figure 91: Number of Unique Generating Units that Experienced an Outage or Derate by Fuel Type, February 8-20, Total Event Area



Numbers of outages, rather than some other measure such as numbers of individual generating units, proved to be the most accurate way to divide the causes of generating unit failures, as well as the fuel types of the generating units. A single generating unit's outages, during an Event lasting nearly two weeks, may have stemmed from multiple causes. For example, a freezing-related outage may have been preceded or followed by a derate caused by natural gas fuel supply issues. Figures 92 and 93 below reflect, for the total Event Area and total Event duration of February 8 through 20, the combined total of all individual generating units outaged and all MW associated with each generating unit outage or derate. So for example, if an (imaginary) generating unit named "ERCOT 1" was a gas unit with a nameplate capacity of 300 MW, and during the Event it experienced an outage, followed by a derate of 100 MW and another derate of 50 MW, it would be reflected in Figures 92 and 93 as one unit, and a total of 450 MW outaged during the Event. The Team acknowledges that the total of 455,698 MW "outaged during Event" may at first glance appear to be an astronomical number and does not mean to convey or imply that this amount of MW was ever outaged simultaneously during the Event. But on the other hand, the number does represent real losses. Every MW of that 455,698 MW was being counted upon by ERCOT, SPP or MISO to serve load at some point during the Event. If the causes of the outages are not addressed, extreme generation failures resulting in firm load shed can continue to reoccur during freezing temperatures.

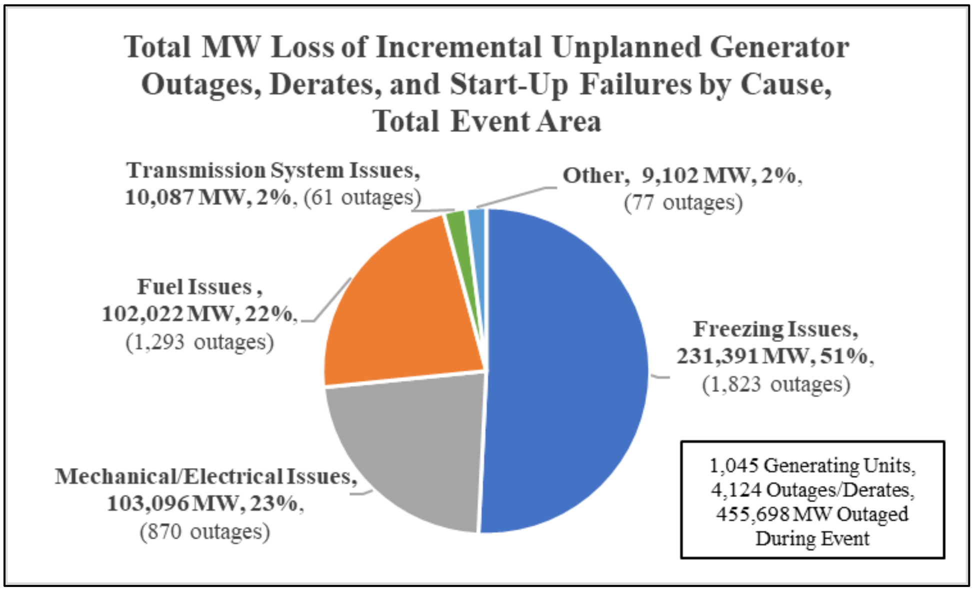
The principal cause of generating unit outages was freezing components and systems resulting from the cold temperatures and precipitation. **Freezing issues and fuel issues combined to cause 75 percent of all unplanned generating unit outages, derates and failures to start during the Event**, as shown in Figure 92 below (as measured by number of outages). Fuel issues included 87 percent natural gas fuel supply issues (decreased natural gas production, terms and conditions of natural gas commodity and transportation contracts, low pipeline pressure and other issues)[236] and 13 percent other fuel issues. Natural gas fuel supply issues alone caused 27.3 percent of all unplanned generating unit outages, derates and failures to start during the Event. Mechanical/electrical issues, responsible for an additional 21 percent of outages, derates and failures to start, also increased as temperatures fell and decreased as temperatures rose, but unlike freezing issues, the method by which the cold affected the generating unit was less obvious.

Figure 92: Number of Incremental Unplanned Generation Outages, Derates, and Failures to Start by Cause, February 8-20, Total Event Area



[236] See section IV.C. for more discussion of natural gas fuel supply issues.

Figure 93: Total MW Loss of Incremental Generation Outages, Derates, and Failures to Start (Outaged MW) by Cause, February 8-20, Total Event Area



Despite multiple recommendations since 2011 that generating units should take actions to prepare for the winter (including detailed recommendations for winterization plans),[237] 49 generating units in SPP (15 percent), 26 in ERCOT (7 percent), and 3 units in MISO South (4 percent), did not prepare any winterization plans. As further evidence that generating units could be better prepared for winter, **81 percent of the generating unit outages**, derates or failures to start **occurred at temperatures above the unit's ambient design temperature**.

The extreme weather spanned two weeks—the weeks of February 7 and 14—with both load and generating unit outages increasing from one week to the next. During the week of February 14, especially in the early morning hours of February 15, generating unit outages and increasing load intersected at the point where ERCOT BA operators no longer had sufficient reserves, and then could no longer balance load and available generation. At its worst point, ERCOT averaged 34,000 MW of generating unit outages and derates based on "expected" capacity[238] (nearly half the amount of ERCOT's actual all-time winter peak load). These outages were sustained for two consecutive days, with the largest proportion being gas-fueled generating units. As a direct result of the massive

[237] https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf (Recommendations 11, 14-19), https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf (Recommendation 1). See also discussion of Recommendation 1 in the 2018 Report (at pp. 88-89) for additional generating unit winterization resources predating the Event.

[238] Expected capacity is less than nameplate capacity and may include adjustments for percentages of wind and solar depending on weather forecasts, and possibly seasonal adjustments to thermal units (for example, a gas turbine could be derated slightly on a hot summer day).

generating unit losses, ERCOT was forced to order an unprecedented 20,000 MW of firm load shed, more than twice the amount of load shed during the 2011 event, and to maintain firm load shed for nearly three days. The magnitude and duration of the manual load shed required during the Event made it difficult to rotate the outages and required system operators to use automatic/UFLS load shed circuits for manual load shed instead.

MISO and SPP also experienced unplanned generating unit outages (included within the Event Area statistics) and needed to shed firm load for energy and/or transmission emergencies. However, their strong connections within the Eastern Interconnection allowed them to import large quantities of MW (reaching a maximum of nearly 13,000 MW on February 15) to mitigate generation shortfalls and meet winter peak energy demands.

B. Causes of Generating Unit Outages

Freezing issues (44.2 percent) and fuel issues (31.4 percent) together caused 75.6 percent of the 4,124 total unplanned generating unit outages, derates, and failures to start during the Event. An additional 21.1 percent of outages, derates, and failures to start were caused by "mechanical/electrical issues," but these issues too were related to the cold temperatures—as temperatures decreased, the number of generating units outaged or derated due to mechanical/electrical issues increased. In total, about 48 percent of ERCOT's, 45 percent of MISO's and 36 percent of SPP's generating unit outages, derates and failures to start during the Event were caused by freezing issues. Sixty percent of all generating units that reported an outage, derate or failure to start during the Event experienced at least one caused by freezing issues (multiple generating units had multiple outages, some from different causes).

Approximately 82 percent of the ERCOT entities that submitted a declaration of preparation for winter had at least one generating unit outaged or derated due to freezing issues, which raises questions about the efficacy of the ERCOT protocols and how the implementation of these protocols is evaluated by ERCOT and enforced by the PUCT.

Freezing issues arise because the generating units are not prepared for the cold temperatures, wind, or freezing precipitation to which they are exposed. Within the freezing issues, certain components and systems of the generating units freeze most often, as shown by the tables and representative generating units below. The top categories, such as frozen transmitters, sensing lines and instrumentation, frozen valves and inlet air systems, and wind turbine blade icing, have repeatedly caused unplanned outages in multiple events. If these most vulnerable elements, deemed "cold-weather-critical components," are better protected before future cold weather events, GOs/GOPs could prevent outages, derates and failures to start. As Figure 94 below shows, a GO need not guess where to focus in preparing for the winter. **Protecting transmitters, sensing lines and instrumentation, as well as wind turbine blades, against icing and freezing could have cut the MW of generating units experiencing an outage by 67 percent in ERCOT, 47 percent in SPP and 55 percent in MISO South**.

Figure 94: ERCOT, SPP and MISO South Generating Unit Freezing Issues Sub-Causes

ERCOT

	Equipment Category	Components and Systems	Generating Units	MW Outaged or Derated[1]	Percent of MW Outaged or Derated
	Turbine Blades (33% of MW Outaged/Derated)	Icing on blades	190	22,231	32.5%
67%	Instrumentation (35% of MW Outaged/Derated)	Frozen transmitter	61	10,757	15.7%
		Frozen sensing lines	37	8,791	12.9%
		Frozen instrumentation	27	4,203	6.2%
	Other Equipment Freezing Problems	Frozen equipment	73	6,941	10.2%
		Frozen valve	31	4,941	7.2%
		Equipment failure	41	4,734	6.9%
		Other freeze-related issue[2]	29	5,705	8.4%

[1] Units with multiple freeze-related outages are counted once per subcause using the maximum MW outaged.
[2] Includes freeze-related subcauses external to the generating unit such as frozen coal or ice on transmission lines.

SPP

	Equipment Category	Components and Systems	Generating Units	MW Outaged or Derated[1]	Percent of MW Outaged or Derated
	Turbine Blades (32% of MW Outaged/Derated)	Icing on blades	63	8,703	32.3%
47%	Instrumentation (15% of MW Outaged/Derated)	Frozen sensing lines	10	1,820	6.8%
		Frozen instrumentation	4	1,236	4.6%
		Frozen transmitter	8	991	3.7%
	Other Equipment Freezing Problems	Frozen equipment	59	6,913	25.7%
		Equipment failure	12	1,476	5.5%
		Frozen valve	11	1,227	4.6%
		Other freeze-related issue[2]	19	4,552	16.9%

[1] Units with multiple freeze-related outages are counted once per subcause using the maximum MW outaged.
[2] Includes freeze-related subcauses external to the generating unit such as frozen coal or ice on transmission lines.

MISO South

	Equipment Category	Components and Systems	Generating Units	MW Outaged or Derated[1]	Percent of MW Outaged or Derated
55%	Instrumentation (55% of MW Outaged/Derated)	Frozen transmitter	23	8,384	39.7%
		Frozen instrumentation	6	1,847	8.7%
		Frozen sensing lines	7	1,440	6.8%
	Other Equipment Freezing Problems	Frozen equipment	16	3,847	18.2%
		Frozen valve	5	1,276	6.0%
		Equipment failure	2	540	2.6%
		Other freeze-related issue[2]	6	3,792	17.9%

[1] Units with multiple freeze-related outages are counted once per subcause using the maximum MW outaged.
[2] Includes freeze-related subcauses external to the generating unit such as frozen coal or ice on transmission lines.

Frozen Sensing Lines and Transmitters: Power plant instrumentation, including transmitters and sensing lines, provides data necessary to monitor various operational parameters and control the generating unit's systems. Typically, sensing lines containing a standing water column are used to sense changes in pressure and a transducer produces an electronic signal that transmits the information to the plant's control systems. In sub-freezing temperatures, if freeze protection is not employed on critical unit systems and instrumentation, the water in the sensing lines can freeze, causing faulty signals and subsequent unit trips or derates.

Other than icing blades on wind turbines, frozen transmitters and sensing lines made up the majority of freeze-related outages and derates during the Event, across all unit types. Frozen sensing lines and transmitters caused outages or derates of dozens of units in all three BA footprints. For example, in ERCOT, a frozen sensing line caused a 932 MW coal generating unit to be derated to 360 MW when a pressure transmitter failed. In MISO, frozen level transmitter sensing lines and chemical feed lines caused two outages of a 511 MW natural gas-fired generating unit. And in SPP, a frozen limestone slurry line caused a 190 MW derate to a coal unit. Other representative outages caused by cold-weather-critical components include:

ERCOT Units:

- Frozen feedwater flow sensing lines caused the outage of a 568 MW natural gas-fired generating unit.
- Frozen steam drum level transmitter sensing lines caused a coal unit to trip at 577 MW due to a false high drum level indication.

MISO Units:

- Erratic drum level transmitters readings related to cold weather caused a 1,000 MW natural gas-fired generating unit to be derated by 130 MW.
- A 6-inch section of sensing line tubing without insulation and heat trace caused a frozen boiler feed pump to trip, thereby causing an 899 MW natural gas-fired generating unit to be derated by 238 MW and later outaged.

SPP Units:

- Freezing of two out of three furnace flow instruments caused a 650 MW coal unit to trip.
- A frozen transmitter led to a false steam drum level indication, shutting down boiler feed pump(s), causing low pressure, and tripping a 165 MW natural gas-fired unit.

Blade Icing: Blade icing caused multiple operational issues for wind generating units during the Event. Precipitation and condensation during cold weather can cause layers of ice to form on turbine blades, causing potential balancing, bearing, and other equipment problems, as well as safety problems when accumulated ice falls from the wind blades, known as “ice throws.” The examples below are characteristic of the operational issues experienced by wind generating units during the Event.

ERCOT Units:

- Blade icing on several turbines resulted in automatic shutdown by turbine controllers to prevent equipment damage, derating a 94 MW wind generating unit by about 50 MW.

- Ice buildup on turbine blades caused aerodynamic degradation of the blades, reducing the ability of the affected wind turbines to produce power, thereby derating a 230 MW wind generating facility to 130 MW.

SPP Unit:

- Icing on blades caused a forced outage of a 400 MW wind generating facility.

Low Temperature Limits: Wind turbines are typically designed to operate within a designated range of ambient temperatures and have an automatic shutdown feature to protect their components in the event the designated range is exceeded. Although manufacturers offer an "extreme cold weather package,"[239] which allows a turbine to continue operating in colder temperatures, GOs surveyed in ERCOT did not typically purchase this option.[240] For example, one 230 MW wind farm was derated by 25 MW and later suffered outages when the turbines, designed to shut down when the temperature drops below five degrees, performed as expected and shut down. Turbine operations, maintenance, and availability are all based on this ambient temperature limitation. In SPP, 32 wind generating units experienced automatic cutoffs once they reached their ambient design temperature limits.

Frozen Equipment (General): Many critical systems besides sensing lines experienced freezing problems caused by the low temperatures. These included emissions systems, feedwater systems, control air systems, lubricating oil systems, and the like. Emissions systems sometimes rely on water, which is susceptible to freezing. Similarly, control air systems contain moisture-laden air which can lead to freezing if the moisture is not removed. Equipment lubricants that are not kept at specified temperatures can also adversely affect the operation of equipment. The following examples illustrate critical system malfunctions due to freezing beyond sensing lines:

ERCOT Units:

- Chunks of ice entered a fan and contacted the rotor, causing a forced draft fan failure, which tripped a 325 MW natural gas-fired generating unit.
- The radiator on the intake of a compressor completely iced over, preventing the compressor from intaking air or compressing air, resulting in a loss of 46 MW at a natural gas-fired generating unit.

SPP Units:

- Inlet filters plugged with snow led to high differential pressure across the filters, forcing a 268 MW gas-fired turbine offline.
- Boiler heat trace and insulation failed on part of the reheat attemperation system,[241] causing a 500 MW coal unit to be outaged.

[239] *General Electric, GE Energy's 2.5xl Wind Turbine Now Offers Extreme Cold Weather Capabilities for Challenging Applications in North America and Europe,* Press Release (Sept. 21, 2009), https://www.renewableenergyworld.com/om/ge-inks-1-gw-in-service-deals-offers-extreme-cold-weather-capabilities-for-2-5xl-turbine/

[240] One large owner of wind turbines in ERCOT confirmed that winterization packages are not typically applied in that region.

[241] A coil of pipe through which hot or cold water may be run, used to control steam temperature in a steam turbine.

Frozen Valves: When exposed to extreme cold weather conditions, the operation of valves can become sluggish. Depending on the particular application of these components, sluggish valves can cause instability in the boiler or turbine controls, which can eventually lead to a unit trip. Below are examples of generating units that experienced valve issues due to cold weather during the Event.

ERCOT Units:

- High-pressure steam water control valves froze, cutting off steam to the turbine and tripping a 262 MW natural gas-fired generating unit.
- Frozen valves and drain lines on auxiliary boilers prevented a 749 MW natural gas-fired generating unit from starting.

MISO Unit: Frozen fuel gas positioners on two heat recovery steam generator units caused a 22 MW derate of a natural gas-fired generating unit.

Frozen Water Lines: The condensate and boiler feedwater systems of steam-cycle generating units (coal, conventional gas, and combined cycle) use water from the condenser and add heat (through a series of feedwater heaters) and pressure (through condensate and boiler feedwater pumps) to increase cycle efficiency before the water enters the boilers. Piping, pressure vessels, and valves within these boiler feeder systems are susceptible to freezing, absent freeze protection measures, especially if the unit is offline at the onset of freezing temperatures. The following examples demonstrate typical operational issues during the Event:

ERCOT Unit:

- The air-cooled condenser at a natural gas-fired unit froze, resulting in elevated backpressure, which caused the unit to trip at 474 MW.

MISO Units:

- A frozen pipe ruptured in the makeup water micro-filtration system, causing a 551 MW natural gas-fired generating unit to be derated by 264 MW.
- Freezing issues on a circulating water system led to a coal plant being derated by 265 MW.

SPP Unit:

- A frozen condensate supply line eliminated all water flow to the heat recovery steam generator boiler piping system, forcing a 350 MW natural gas-fired generating unit offline.

These failures occurred despite the fact that the Event was the fourth cold weather event in the U.S. in the past 10 years which jeopardized BES reliability, and several of those events resulted in published reports and recommendations. The Team questioned GOs and GOPs involved in the Event about whether they incorporated voluntary recommendations available to industry from either of two sets of past recommendations: the 2011 Report recommendations, and NERC's Reliability Guideline on Generating Unit Winter Readiness, which originally dates to 2012 (but is frequently updated). Over 40 percent of the GOs/GOPs in the south central U.S. regions where "freezing issues" were identified as the predominant cause of unplanned generation outages, derates or failures to start (ERCOT and MISO South) stated that they did not incorporate specific generator-related recommendations from the 2011 Report or specific recommendations from the Guideline.[242]

C. Natural Gas Supply and Delivery[243]

Generating unit outages and natural gas fuel supply and delivery were inextricably linked in the Event. Fuel issues, at 31.4 percent, were the second largest cause of unplanned outages, derates and failures to start during the Event. Eighty-seven percent of the fuel issues involved natural gas fuel supply issues and 13 percent involved issues with other fuels (such as coal or fuel oil), as shown in Figure 95, below. Natural gas fuel supply issues alone caused 27.3 percent of the generating unit outages. Natural gas fuel supply issues include declines in natural gas production, the terms and conditions of natural gas commodity and transportation contracts, low pipeline pressure and other issues. During the Event, unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins to prevent imminent freezing issues, and unplanned outages of gathering[244] and processing[245] facilities decreased the natural gas available for supply and transportation to many natural gas-fired generating units in Texas and the South Central U.S.

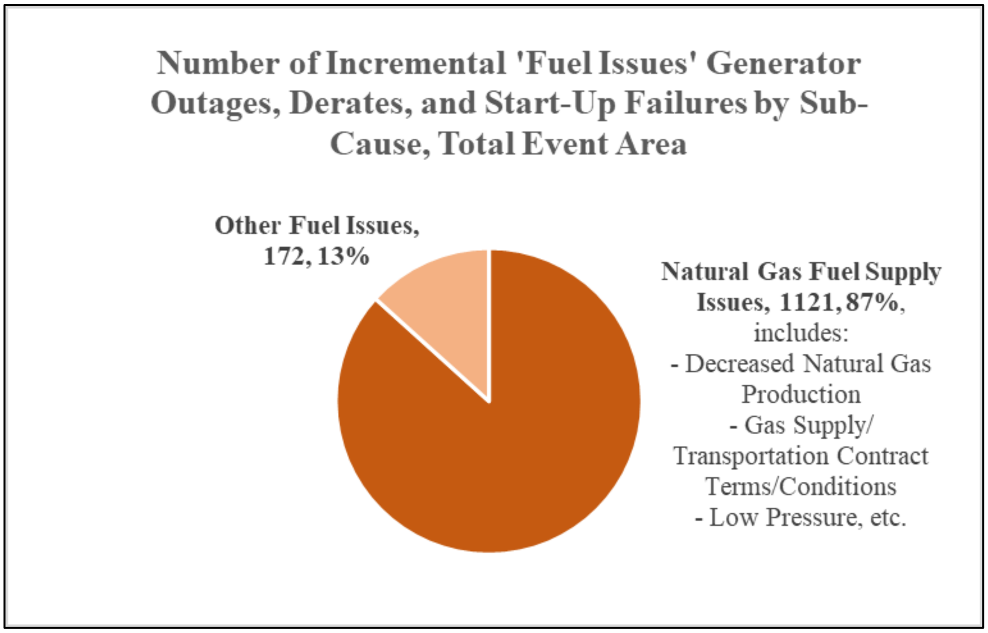
242 The Team requested data from GOs/GOPs in ERCOT, MISO South and all of SPP, based on where energy emergencies occurred. SPP's largest cause of unplanned outages, derates, or failures to start of accredited BES generation across its entire footprint during the Event was natural gas fuel supply issues, not freezing issues. Unlike ERCOT and MISO South, which have their entire footprints in warmer climates and have open-frame generating units, SPP's footprint includes some of the northernmost regions of the U.S. (e.g. North Dakota), where large numbers of enclosed generating units are designed to withstand extremely low temperatures.

243 Unless otherwise stated, the source of data for this section is the sample of producers, processors and pipelines that responded to the Team's data requests. *See* Appendix I.

244 Gathering facilities include extensive low-pressure natural gas lines which aggregate the production of several separate natural gas wells into one larger receipt point. *See* AGA Natural Gas Glossary, "Gathering" definition.

245 Processing involves extracting or removing initial components (liquefiable hydrocarbons, such as propane, butane, ethane, or natural gasoline) from the natural gas stream. *See* AGA Natural Gas Glossary, "Processing Plant" definition.

Figure 95: Fuel Issues – All Generation Types

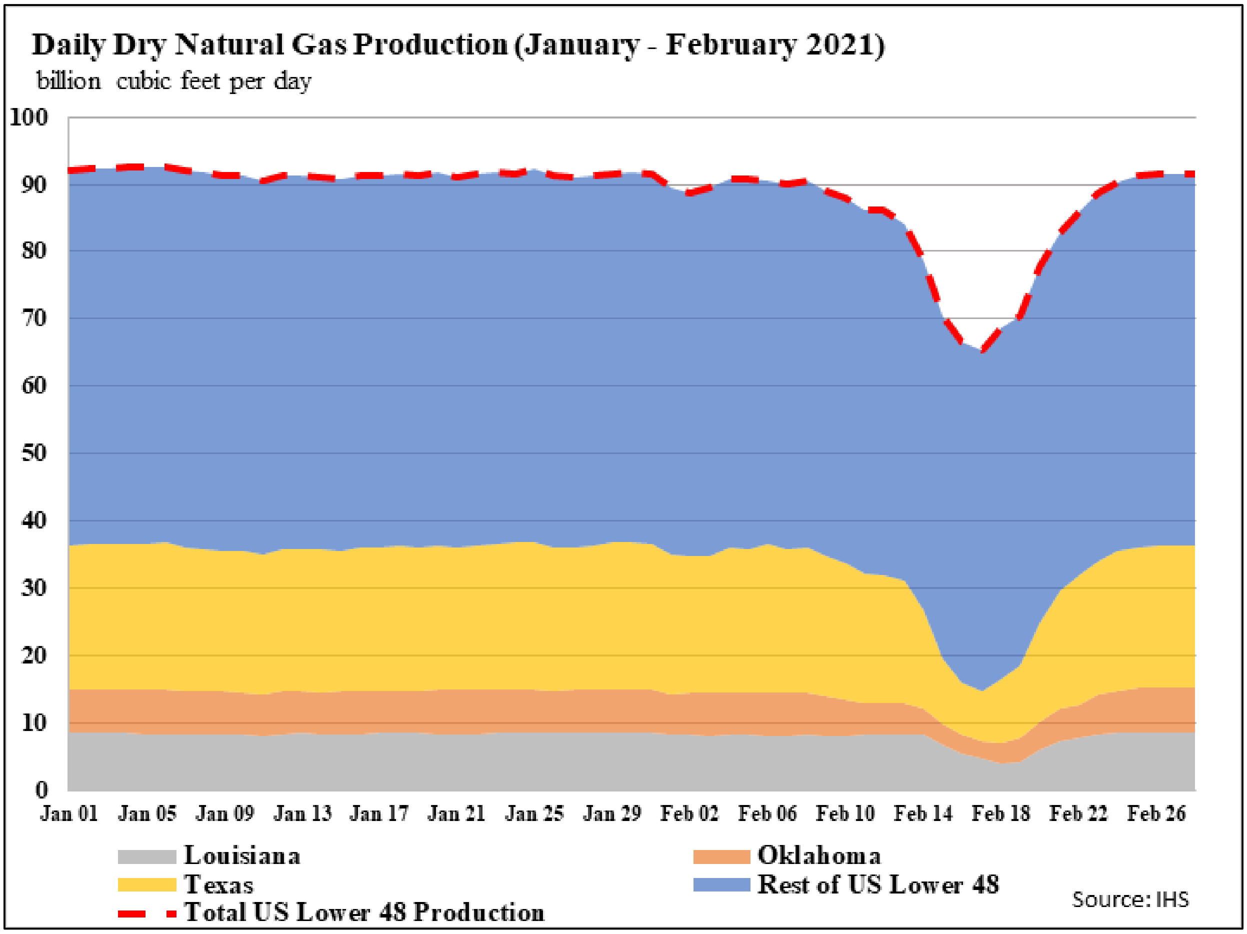


Natural gas-fired units also represented the largest percentage of generating units that experienced unplanned outages, derates, or failures to start, whether examining the fuel type of generating units by number of units, outages, or nameplate MW capacity, as shown in Figure 3, above.

Natural gas fuel supply issues overview. From February 8 through February 20, the combined effects of decreased natural gas production, the specific terms and conditions of natural gas commodity and pipeline transportation contracts, and other issues like low pipeline pressure, resulted in a total of 357 individual natural gas-fired generating units within ERCOT (185 units), SPP (141 units) and MISO South, (31 units) experiencing 1,121 outages, derates or failures to start.[246] Although having firm supply or transportation contracts did not guarantee a generating unit remained online, only 29 percent (109 units) of the natural gas-fired generating units with unplanned outages had both firm natural gas supply and firm natural gas pipeline transportation contracts.[247]

[246] The impact of production declines on natural gas-fired generating units is not always immediate, due to the pipelines' preparations for the storm (e.g., line packing, use of storage, etc.).
[247] *See* Figure 103 for more information on the contractual arrangements held by the GOs/GOPs involved in the Event.

Figure 96: Daily Dry Natural Gas Production (January - February 2021)



Wellhead Effects on Production. A significant level of wellhead freeze-offs during the Event lowered natural gas production. As a result, total U.S. Lower 48 natural gas production fell to 65.4 Bcf/d on February 17, a 28 percent decline from the 90.8 Bcf/d production level seen on February 8 (as seen on Figure 96 above). Most producing regions of the U.S. saw a sharp weather-related decline and recovery as illustrated in Figure 96, above: when temperatures fell, regional production dropped, and as temperatures rose after the Event, regional production recovered, eventually to pre-Event levels. The largest Event-related impacts on natural gas production were in Texas, Oklahoma, and Louisiana. Texas production declined by 70.1 percent, Oklahoma production by 56.8 percent and Louisiana production, by 53.5 percent, as compared to January 2021 average production.[248] Average production declines in these states constituted over 80 percent of the total

[248] In its Preliminary Findings and Recommendations, the Team had calculated 2021 natural gas production declines against the average for early February, however, to compare the 2011 and 2021 events, the Team needed to switch to the average for the month of January because the 2011 event occurred from February 1 to 5. The source for all figures in this paragraph is IHS data shared with the Team.

declines across the entire lower 48 States during the period from February 15-20 when compared to average production in January 2021.

Weather/Freeze-Related Effects on Production. The majority (58 percent) of the decline in natural gas production during the Event was weather/freeze-related, as shown in Figure 97 below. This category includes production declines directly caused by freezing, preemptive shut-ins to protect natural gas facilities from freeze-related impacts, and poor road conditions (due to precipitation) that prevented the removal of fluids from production sites or access to facilities to make necessary repairs.

Loss of Power Supply to Natural Gas Infrastructure. For the Event overall, loss of power supply to natural gas infrastructure caused 23.5 percent of the decline in natural gas production. Power outages at natural gas infrastructure facilities were caused by both weather and manual firm load shedding. Because many natural gas infrastructure loads had not been identified as critical loads to be protected from manual firm load shedding, and power outages caused by weather and firm load shed were coincident, the exact extent of firm load shed-caused power outages to critical natural gas infrastructure loads is unknown. However, the firm load shed did not begin until the early morning of February 15, so natural gas production declines caused by power outages and occurring before that time would necessarily have been caused by weather-caused power outages.

Calculating the exact percentage of production declines caused by power outages daily during the Event posed challenges. One complicating factor is that producer data uses the gas day (9 a.m. Central to 9 a.m. Central), while grid and generating unit data is based on the calendar day. The natural gas production and processing entities did not provide data in sufficient granularity for the Team to split their data between calendar days February 14 and 15. However, the percentage of production declines caused by power outages varied little between the overall Event (23.5 percent), February 14 (20.2 percent), and February 17, the day of maximum production losses (23 percent). See Figures 97 - 99, below, which attribute production losses to various causes, including "midstream-loss of power supply" and "well/gathering facilities-loss of power supply," based on each cause's proportionate volumetric share.

Figure 97: Natural Gas Production Event Causes, February 8-20, 2021

Production Event Causes on February 8th - 20th

		Natural Gas Infrastructure Condition	Facility Event Causes
86%	Freezing Temperature and Weather Conditions (43.2% of production disruptions)	Facility Shut-ins to Prevent Imminent Freezing Issues	18.0%
		Freezing Issues - Midstream	5.1%
		Freezing Issues at Well and Gathering Facilities	11.1%
		Freezing Issues on Roads/Access to Well and Gathering Facilities	9.1%
	Loss of Power Supply (21.4% of production disruptions)	Midstream - Loss of Power Supply	10.4%
		Well/Gathering Facilities- Loss of Power Supply	11.1%
	Multiple Issues (21.3% of production disruptions)	Multiple Issues (combination of two or more of above issues)	21.3%
	Other Issues, Unrelated Issues (14% of production disruptions)	Midstream - Line Pressure	4.9%
		Midstream - Other	0.4%
		Well and Gathering Facility Issues - Not Applicable to Event	8.8%
	Total		100.0%

Figure 98: Natural Gas Production Event Causes for February 14, 9:00 a.m. to February 15, 9:00 a.m. Gas Day (inclusive of a portion of ERCOT Load Shed Event)

Production Event Causes on February 14th (Gas Day, inclusive of a portion of ERCOT Load Shed Event)

		Natural Gas Infrastructure Condition	Facility Event Causes
88.4%	Freezing Temperature and Weather Conditions (52.1% of production disruptions)	Facility Shut-ins to Prevent Imminent Freezing Issues	33.6%
		Freezing Issues - Midstream	2.2%
		Freezing Issues at Well and Gathering Facilities	15.6%
		Freezing Issues on Roads/Access to Well and Gathering Facilities	0.8%
	Loss of Power Supply (18.1% of production disruptions)	Midstream - Loss of Power Supply	10.0%
		Well/Gathering Facilities- Loss of Power Supply	8.1%
	Multiple Issues (18.2% of production disruptions)	Multiple Issues (combination of two or more of above issues)	18.2%
	Other Issues, Unrelated Issues (11.6% of production disruptions)	Midstream - Line Pressure	1.6%
		Midstream - Other	0.0%
		Well and Gathering Facility Issues - Not Applicable to Event	10.0%
	Total		100.0%

Figure 99, below examines the peak day for natural gas production loss, which occurred on the February 17 gas day (9 a.m. February 17, to 9 a.m. February 18). Even during this period, loss of power supply only caused 21 percent of production declines, while 44.5 percent were caused by freezing/weather-related issues.

Figure 99: Natural Gas Production Event Causes – February 17, 9:00 a.m. to February 18, 9:00 a.m. Gas Day of Maximum Production Losses

Production Event Causes on February 17th (Day of Maximum Production Losses)

		Natural Gas Infrastructure Condition	Facility Event Causes
85.7%	Freezing Temperature and Weather Conditions (44.5% of production disruptions)	Facility Shut-ins to Prevent Imminent Freezing Issues	18.5%
		Freezing Issues - Midstream	5.3%
		Freezing Issues at Well and Gathering Facilities	10.0%
		Freezing Issues on Roads/Access to Well and Gathering Facilities	10.7%
	Loss of Power Supply (21.6% of production disruptions)	Midstream - Loss of Power Supply	8.8%
		Well/Gathering Facilities- Loss of Power Supply	12.7%
	Multiple Issues (19.6% of production disruptions)	Multiple Issues (combination of two or more of above issues)	19.6%
	Other Issues, Unrelated Issues (14.3% of production distruptions)	Midstream - Line Pressure	5.9%
		Midstream - Other	0.5%
		Well and Gathering Facility Issues - Not Applicable to Event	7.9%
	Total		100.0%

Figure 100, below examines the issue from the perspective of the natural gas-fired generating units that experienced outages, derates or failures to start due to natural gas fuel supply reductions, and compares whether the outages happened before or after the firm load shed began early on February 15. The majority of natural gas production/supply declines in Oklahoma, northern and western Texas occurred before February 15, the first day on which firm load shed occurred, while the majority of the production declines in central, eastern, and southern Texas and Louisiana occurred on and after February 15. Sixty percent of all natural gas-fired units affected by natural gas fuel supply issues had already experienced outages, derates, or failures to start by February 14, before any firm load had been shed, while 32 percent had fuel supply issues both before and after the firm load shed began. The data in Figure 100, below, unlike data from natural gas infrastructure entities, is directly from the GOs/GOPs, which use the 24-hour day. All outages shown as occurring on February 14 are the result of natural gas fuel supply issues that happened before any firm load had been shed.

Figure 100: Natural Gas-Fired Generating Unit Outages, Derates or Failures to Start due to Natural Gas Fuel Supply Issues - Before and After ERCOT Firm Load Shed

Natural gas fuel supply Issues caused outages/derates/failures to start:	2/8 - 2/14 (Prior to Firm Load Shed)	2/15 - 2/20 (During and After Firm Load Shed)
Total Individual Generating Units	**213**	**258**
ERCOT BA Footprint	111	134
SPP BA Footprint	91	103
MISO South Footprint	11	21

Effects on Natural Gas Processing Facilities. Natural gas processing facilities necessarily are dependent on natural gas production, and thus reduced receipts from production caused the majority (61 percent) of processing declines experienced during the Event, as shown in Figure 101, below. Loss of power (18 percent) and freezing issues at processing facilities (13 percent) were the next two largest causes of the decline in processing. The share of processing declines caused by power outages increased by six percentage points between February 14, before any firm load shed had occurred (15 percent of processing declines), and February 17, when processing facility losses were the greatest (21 percent of processing declines).

Figure 101: Natural Gas Processing Facility Event Causes for Specific Timeframes

Processing Facility Event Causes on February 8 - 20

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
92%	Freezing Temperature and Weather Conditions (74% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	61%
		Freezing Issues at Processing Facilities	Processing Facility Disruption	13%
	Loss of Power (18% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	18%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	8%
	Total			100%

*There were a total of 67 causes of processing plant events occuring from February 8 to February 20.

Processing Facility Event Causes on February 14

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
100%	Freezing Temperature and Weather Conditions (85% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	73%
		Freezing Issues at Processing Facilities	Processing Facility Disruption	12%
	Loss of Power (15% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	15%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

*There were a total of 34 causes of processing plants events occuring on February 14.

Processing Facility Event Causes on February 17

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
100%	Freezing Temperature and Weather Conditions (79% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	76%
		Freezing Issues at Processing Facilities	Processing Facility Disruption	3%
	Loss of Power (21% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	21%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

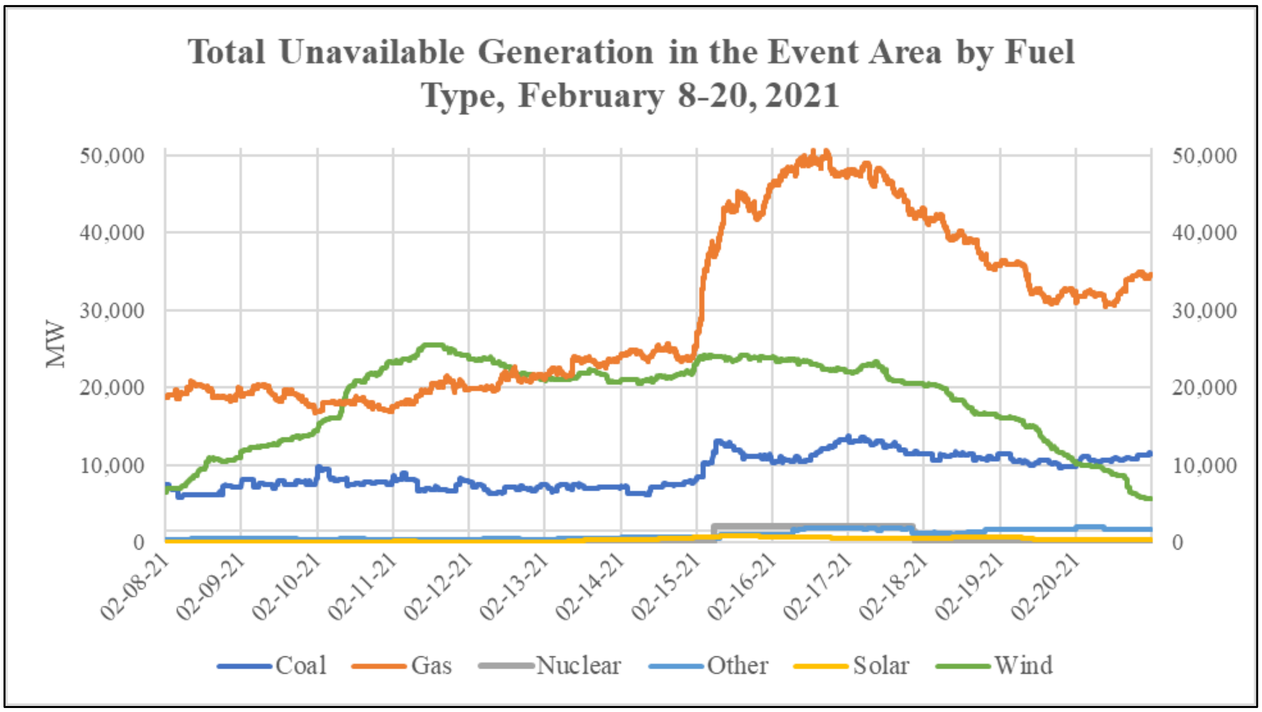
*There were a total of 33 causes of processing plant events occuring on February 17.

While some pipelines declared force majeure[249] and others had low pressure issues, many pipelines pointed out that they were able to meet all firm commitments. Only 29 percent of the generating units with unplanned outages due to fuel supply issues had both firm transportation and firm commodity contracts. The effect on pipelines during the Event differed from the previous worst

249 *See* Figure 57.

event, 2011, due to the record reductions in production of natural gas as well as the unprecedented numbers of natural gas-fired generating units that failed to perform.[250] Both natural gas production decline percentages and natural gas-fired generating unit outages dramatically increased in 2021 as compared to 2011. For example, Texas peak natural gas production during the January 1 to 5, 2011 event declined by 22 percent as compared to the January average in 2011, but Texas peak natural gas production during the Event declined by 70.1 percent as compared to January production in 2021. The Oklahoma peak natural gas production decline was also 22 percent in the 2011 event, but was 56.8 percent in 2021, while Louisiana production appeared unaffected in the 2011 event, but peak natural gas production declined 53.5 percent in 2021, as compared to January. From the onset of the Event, unplanned natural gas-fired generating unit outages and derates for the total Event Area increased by approximately 30,000 MW (primarily due to freezing issues and natural gas fuel supply issues) as of February 16, 2021, compared to 14,702 MW of generating unit outages, derates and failures to start for all fuel types of generation in 2011 in ERCOT.[251] See Figure 102, below.

Figure 102: Total Unavailable Generation in the Event Area by Fuel Type, February 8-20, 2021



[250] The 2011 arctic cold front caused estimated production declines of 5.5 Bcf/d on February 1 to 4, with an estimated total production decline of 14.8 Bcf. The San Juan and Permian Basins were especially hard hit. 2011 Report at 113-115. These declines propagated downstream and ultimately resulted in natural gas curtailments to more than 50,000 customers in New Mexico, Arizona, and Texas, including the cities of El Paso, Texas, and Tucson, Arizona. The production losses “stemmed principally from three cause: freeze-offs, icy roads, and [firm load shed].” 2011 Report at 2, 9. As in the Event, icy roads also prevented maintenance crews from reaching the wellheads to remove produced water, which, if not removed, causes the wellheads to shut down automatically once tanks are full.

[251] 2011 Report, page 78. The natural gas-fired generating outages for the 2011 event area are not available, however, as in the Event, ERCOT had the largest generation outages and firm load shed in 2011.

D. Grid Preparedness and Emergency Operations

1. Peak Load Forecasts and Reserve Margin Calculations

50/50, 90/10 winter peak load forecasts for southern U.S. areas. The winter season peak load forecasts used in calculating winter season reserve margin projections for the ERCOT, MISO South and SPP footprints were substantially lower than the actual peak load demand during the Event (including the firm load shed). While neither the 50/50 nor the 90/10 case is expected to predict any given day's load exactly, the 90/10 case has typically in the past served as a proxy for the more extreme load results that could be expected in a season. But given the occurrence of extreme cold weather events in the U.S., as well as the potential for significant resistive heating load during those events in southern states, which can quickly escalate load, other extreme scenarios beyond the 90/10 case should be included when planning for winter loads, especially in the South/South Central/Southwest.

The expected, or 50/50, seasonal peak load forecast methodologies are typically based on multiple years of actual winter peaks. Because the 50/50 and 90/10 use the same historical sampling, which in southern climates includes multiple years of mild-weather peak loads and very few cold-weather peak loads, the 90/10 cases for the BAs involved in the Event did not adequately predict extreme load days on which resistive heating might activate. The 90/10 winter season peak load forecasts for each BA footprint were lower than actual peak loads during the Event as follows: ERCOT, 14.3 percent lower; SPP, 4.8 percent lower; MISO South; 5.7 percent lower.[252] Historical samplings limited to winters where extreme cold weather occurred (i.e. when auxiliary resistive heating load[253] would have been prevalent) can provide a data source for developing extreme scenario winter peak load forecasts that could yield improved accuracy of forecast winter peak reserve margins.

Available generation capacity during winter peak conditions. The generation capacity component used in the NERC winter reliability assessment to calculate reserve margins assumes that natural gas-fired generating units without firm natural gas contracts and/or firm pipeline transportation will be able to produce their full capacity when called upon. For example, for winter 2020-2021, SPP expected to have 29,965 MW[254] of natural gas-fired generation capacity. However, during the Event, natural gas fuel supply issues resulted in over 15,000 MW of this capacity (over half of its natural gas-fired generation capacity) being outaged or derated at SPP's highest period[255] of generation unavailability. During the Event, ERCOT, SPP and MISO South had 357 natural gas-fired generators outaged or derated due to natural gas fuel supply issues (commodity and transportation). Natural gas fuel supply issues were the second-largest cause of unplanned outages,

[252] Likewise, the expected or "50/50" winter season peak load forecasts were also low: ERCOT, 33.1 percent too low; SPP, 11.7 percent too low; MISO South, 8.9 percent too low.
[253] *See* Figure 108 for a graph of how demand rises as ambient temperature falls when auxiliary heating is employed.
[254] Accredited Capacity Winter 2020-2021, for gas fueled generation. *See* also Figure 103 and related discussion regarding the generating units' natural gas fuel supply arrangements.
[255] February 17 at 12:17 AM

derates and failures to start during the Event.[256] During winter peak conditions, when non-firm natural gas supply and transportation are at a higher risk of being unavailable, using the full capacity of such generators in anticipated reserve margin calculations does not adequately capture natural gas fuel supply uncertainties, which resulted in overstating available capacity values used in calculating winter peak reserve margins for the NERC winter seasonal assessment.

Expected capacity of intermittent resources.[257] The percentages of nameplate wind generation presently included as capacity in winter reserve margins similarly may not be representative of those generating units' actual availability during an actual event. For example, ERCOT included 8,100 MW of wind generation as capacity in its internal 2021 annual reserve margin. For the 2020/2021 ERCOT Winter SARA, ERCOT estimated 7,070 MW[258] to be available during winter peak (with a low wind output scenario dropping to 1,791 MW). But for the 72-hour period during February 15-17 during which ERCOT shed firm load, ERCOT wind output averaged only 3,100 MW per hour, dropping as low as approximately 500 MW at one point. Wind generation was unavailable due to both icing conditions and low wind speeds. Winter season reliability assessments should provide more specifics and quantification of risks, including scenarios where there is a likelihood of conditions occurring simultaneously (e.g., both low wind and freezing precipitation scenarios).

MISO South 90/10 Load Forecast*:* MISO determines its Load Forecast Uncertainty percentage based on the actual highest summer peak load day for each of the past 30 years. Because MISO then multiplies the ten local/zonal 50/50 *winter* peak forecasts by this *summer* Load Forecast Uncertainty percentage, MISO South's winter 90/10 load forecast was only 3.9 percent higher than the 50/50 winter forecast for the whole MISO BA. The Load Forecast Uncertainty percentages of local resource zones 8, 9, and 10 (which make up MISO South) are small (4.1 percent, 2.3 percent, and 4.4 percent, respectively) for summer, because hot, humid temperatures occur every single year in MISO South. However, MISO South/zones 8, 9 and 10 could have significantly higher Load Forecast Uncertainty percentages during winter peaks, due to the volatility of winter load spikes from electric heat.

SPP 90/10 Load Forecast: SPP provides a "90/10" load forecast value to NERC for its Winter Reliability Assessment, but the number that SPP provides is based on its 50/50 load forecast

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[256] Similarly, in early January 2014 during the east coast polar vortex event, the cold weather also increased demand for natural gas, which resulted in a significant amount of gas-fired generation being unavailable due to natural gas fuel supply issues. Polar Vortex Review at page iii. Gas-fired generation was also a significant source of unplanned outages and derates in the 2011 and 2018 events. 2011 Report at 153 (natural gas fuel supply issues contributed a little less than ten percent of the total MW that were out at the worst point during the 2011 event); 2018 Report at 10 (16 percent of unplanned generating unit outages caused by natural gas fuel supply issues). The Team acknowledges that some of the ISOs/RTOs involved in these events have taken steps in response, some of which required, and received, Commission approval. For freezing issues causing unplanned solar resource outages and derates, see Appendix D.

[257] The expected capacity of solar in each footprint was negligible, representing only 0.2 to 0.4 percent of expected capacity, so it did not have as great an effect on the reserves of these BAs as wind. If a BA relied on solar for a greater share of its expected capacity, the same caveat could apply to solar. While wind turbines are vulnerable to icing, a recent machine-learning study of maintenance records by Sandia National Labs identified snow events as causing the largest performance reductions at solar facilities. Nicole D. Jackson & Thushara Gunda, *Evaluation of extreme weather impacts on utility-scale photovoltaic plant performance in the United States*, 302, Applied Energy, 1:7 (2021).

[258] *See* footnote 66 for details on how ERCOT estimated this value.

increased by five percent. SPP does not currently develop a statistically-based 90/10 load forecast; other BAs like ERCOT and MISO do.

2. Emergency Operations Analysis

Managing Transmission Congestion. ERCOT, MISO and SPP maintained effective situational awareness of the real-time conditions of the BES during the Event, and promptly responded to maintain BES reliability throughout the Event. MISO's and SPP's ability to transfer nearly 13,000 MW of power through their numerous ties with adjacent BAs in the Eastern Interconnection helped to alleviate portions of their generation shortfalls with imports from BAs that were not experiencing the extreme cold weather. These transfers were not without consequences. The most threatening to BES reliability was the potential IROL identified by MISO RC for the loss of its next-worst contingency, a 345 kV transmission line. Minutes later, at 6:10, the next-worst contingency actually occurred, and after MISO verified it was an IROL at 6:18 a.m., MISO curtailed SPP's imports, which resolved the IROL.

Load Shed. ERCOT, unlike MISO and SPP (who collectively imported nearly 13,000 MW), did not have the ability to import many thousands of MW from the Eastern Interconnection, and thus needed to shed the greatest quantity of firm load to balance electricity demands with the generating units that were able to remain online. By 7:00 p.m. on February 15, ERCOT had ordered 20,000 MW of manual firm load shed, which it sustained for nearly three days. The combined magnitude and duration of manual firm load shed needed to maintain BES reliability in ERCOT, ranging from 14-28 percent of ERCOT's peak load caused electric service providers (TOPs, TOs and DPs) to have difficulties in rotating the controlled outages to customers. Operators needed to use electric circuits configured for automatic load shed (e.g., underfrequency load shed/UFLS) for manual firm load shed. In ERCOT, at least 25 percent of the load is required to be reserved for automatic load shedding (and this does not include critical loads protected from manual load shedding, such as hospitals, police stations, etc.).

Because it is not the entity that implements load shedding, ERCOT did not anticipate that its use of firm load shedding to preserve system stability would contribute to power outages of natural gas production and processing facilities, that would in turn, contribute to the decline in natural gas supply and delivery to natural gas-fired generating units. The manual load shed plans (of TOPs) and automatic underfrequency load shed plans (of TOs and DPs) within the ERCOT footprint were designed to avoid controlled power outages to priority or critical electric loads if the need to shed firm load arose. However, most of the natural gas production and processing facilities surveyed were not identified as critical load or otherwise protected from manual load shedding.

V. Key Recommendations[259]

The magnitude of the Event, and the seriousness of the consequences that resulted from the firm load shed in ERCOT, warrant prompt implementation of the Recommendations. To create a sense of urgency, each Recommendation is assigned to one of four timeframes within which it can and should be implemented.[260] Recommendations assigned to the first timeframe can and should be implemented before winter 2021-2022 (the Team suggests November 1 as the beginning of "winter"). Recommendations assigned to the second timeframe can and should be implemented before winter 2022-2023. Recommendations assigned to the third timeframe can and should be implemented before winter 2023-2024, and the fourth timeframe (Implementation Timeframe D) includes recommendations which could extend beyond winter 2023-2024, but should be completed as soon as possible. See Figure 114 at the conclusion of the Recommendations for a full list of the Recommendations and their assigned timeframes.

A. Electric Generation Cold Weather Reliability

Key Recommendation 1 (a through g): The NERC Reliability Standards should be revised as follows:

Key Recommendation 1a: To require Generator Owners to identify cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems[261] are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start. (Winter 2023-2024)

Key Recommendation 1b: To require Generator Owners to identify and implement freeze protection measures for the cold-weather-critical components and systems (see Key Recommendation 1f., below, for guidance on ambient temperature and weather conditions to be considered). The Generator Owner should consider previous freeze-related issues experienced by the generating unit, and any corrective or mitigation actions taken in response. At an interval of time to be determined by the Balancing Authority, the Generator Owner should analyze whether the list of identified cold-weather-critical components and systems remains accurate, and whether any additional freeze protection measures are necessary. (Winter 2023-2024)

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[259] While all Recommendations are important to preventing recurrence of the Event, Key Recommendations focus on revisions to the Reliability Standards, actions to prevent electric generating unit and natural gas infrastructure freezing issues, grid operations and gas-electric coordination measures for cold weather preparedness.
[260] For mandatory Reliability Standards, implementation means that new and/or revised Standards that address the Recommendation are proposed to the Commission for approval within the timeframes listed with the Recommendations below. In the FERC-approved NERC Rules of Procedure, Appendix 3A Standard Processes Manual, NERC can deviate from its normal process when necessary to meet an urgent reliability issue. *See* https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.
[261] Examples include instrumentation, transmitters, sensing lines and wind turbine blades. *See* Figure 94 and related discussion in IV.B, above.

Since 2011,[262] staff from the Commission, NERC and the Regional Entities have periodically alerted industry to the need for generating units to prepare for cold weather, especially the non-enclosed units found in southern and other warm-weather regions of the U.S. Together, they have issued two prior inquiry reports regarding cold weather events in which multiple generating units experienced outages, derates and failures to start, jeopardizing BES performance.[263] The 2018 Report found that the event was "caused by failure to properly prepare or 'winterize' the generation facilities for cold temperatures."[264] In 2011, the report found "many generators failed to adequately apply and institutionalize knowledge and recommendations from previous severe winter weather events, especially as to winterization of generation and plant auxiliary equipment."[265] Both the 2011 and 2018 Reports identified certain equipment that more frequently contributed to generating unit outages, including frozen sensing lines, frozen transmitters, frozen valves, frozen water lines, and wind turbine icing.[266,267] The Event was no different—generation freezing issues were the number one cause of the Event, and the same frequently-seen frozen components reappear. Given the repeated appearance of certain equipment in causing generating unit outages during cold weather events, NERC recommends in its Reliability Guideline that entities responsible for generating units "identify and prioritize critical components, systems and other areas of vulnerability." NERC further explains in its Reliability Guideline that "this includes critical instrumentation or equipment that has the potential to . . . initiate an automatic unit trip . . . impact unit start-up[,]. . . initiate automatic unit runback schemes or cause partial outages."[268]

In response to the finding in the 2018 Report that one third of the GOs/GOPs surveyed still had no winterization provisions after multiple recommendations on winter preparedness for generating units,[269] the 2018 Report recommended potential new or revised Reliability Standards to address the need for generating units to prepare for cold weather and the need for BAs and RCs to be aware of specific generating unit limitations, such as ambient temperatures or fuel supply. That recommendation led to the Reliability Standards being revised (effective April 1, 2023)[270] to require, in part, that "[e]ach Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: . . . Generating unit(s) freeze protection measures based on geographical location and plant configuration; . . . Annual inspection and maintenance of generating unit(s) freeze protection measures . . .." Although the revised EOP-0011-2 requires GOs to have a

[262] *See* section II.D.1., above, for a discussion of the 2011 event.

[263] https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf; https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf.

[264] 2018 Report at 80-81.

[265] 2011 Report at 195.

[266] 2011 Report at 142.

[267] 2018 Report at 82.

[268] Reliability Guideline at 3.

[269] Despite multiple recommendations that generating units take actions to prepare for the winter (and providing detailed suggestions for winterization), 40 generating units in SPP (10.5 percent), 35 in ERCOT (8 percent), and one unit in MISO (one percent), still did not have winterization plans.

[270] Approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021).

plan which includes freeze protection measures, it does not require them to actually implement any specific freeze protection measures on their equipment.

Key Recommendations 1a and 1b take the next logical step by requiring GOs to (i) identify the cold-weather-critical components and systems and (ii) identify and implement freeze protection measures for those components and systems. Cold-weather-critical components and systems are the components and systems most responsible for the generating unit outages, derates and failures to start which have plagued grid operators in the four studied cold weather events in the last 10 years. Those components and systems (including wind turbine blades, transmitters, sensing lines and instrumentation) froze, caused trips, derates or failures to start, and, during the Event, were responsible for over 68,000 MW of generating unit outages in ERCOT, nearly 27,000 MW in SPP and over 21,000 MW in MISO South.[271] With implementation of this Key Recommendation, BAs and RCs would no longer have to struggle to recover from preventable outages of generating units.

GADS' extensive cause codes currently provide information about each component's role in causing generating unit outages. NERC should make changes to GADS reporting that will allow for identification of the specific operating conditions that contribute to equipment failures (e.g. freezing conditions, frozen precipitation, etc.) to better allow for tracking of trends related to performance of cold-weather-critical components and systems.

<u>Key Recommendation 1c</u>: To revise EOP-011-2, R7.3.2[272] to require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data. (Winter 2023-2024)

EOP-011-2, R7.3.2 (effective April 1, 2023) requires a GO to include in its cold weather preparedness plan, at a minimum, the generating unit's minimum design temperature, historical operating temperature or current cold weather performance temperature determined by an engineering analysis. This Key Recommendation would also require GOs to understand how precipitation and the accelerated cooling effect of wind limit their generating unit's performance. Frozen precipitation can lead to icing issues that affect equipment necessary for the operation of the generating unit, for example ice accumulation on wind turbine blades, air inlet filters, and vents necessary for cooling equipment.

The unit's ambient temperature design may not have factored in the accelerated cooling effect of wind. The 2011 Report identified the accelerated rate of heat loss caused by wind as a factor in that event's generating unit outages, derates and failures to start. The Report explained that "sustained high winds can quickly and continuously remove the heat radiating from boiler walls, steam drums, steam lines, and other equipment in an electric generating station, causing ambient temperatures to

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[271] *See* Figure 94 above.

[272] EOP-011-2 (Emergency Preparedness and Operations) is part of the Reliability Standards recently approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021). Among other things, this Reliability Standard requires GOs/GOPs to have cold weather preparedness plans which include minimum design, historical operating, or cold weather performance temperature data for the GO's generating units.

drop below freezing in spite of the heat being produced by the facility."[273] In other words, the temperature may be within the generating unit's ambient temperature design limitations, but precipitation or the cooling effect of wind can result in the generating unit being inoperable. Knowing the ambient temperature design and the effects of wind or precipitation allows GOs to prepare when the temperature is forecasted to reach their generating units' ambient design limitations. Preparing a generating unit for all potential effects of a cold weather event, whether induced by cold ambient temperatures alone, or cold ambient temperatures plus wind, and ice, can increase the likelihood that the generator will remain operational throughout the event.

The Event demonstrated that ambient temperatures alone do not serve as a basis to predict whether a generating unit can perform during predicted cold weather. For **81 percent of the generating units outaged, at the time the outage occurred, ambient temperatures were above the generating unit's stated design criteria**. While half of the generating units that experienced an outage, derate or failure to start due to freezing experienced a minimum temperature below their design criteria at some point during the Event, the other half experienced an outage or derate due to freezing issues without ever experiencing temperatures below their ambient temperature design criteria. This Key Recommendation would revise EOP-011-2, R7.3.2 to require consideration of the effect of wind and precipitation on the generating unit.

<u>Key Recommendation 1d</u>: To require Generator Owners that experience outages, failures to start, or derates due to freezing to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The Standards Drafting Team should specify the specific timing for the CAP to be developed and implemented after the outage, derate or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season. (Winter 2022-2023)

FERC-NERC-Regional Entity joint staff reports and NERC's Reliability Guideline have recommended various voluntary evaluations of generating unit cold weather performance. The 2011 Report recommended that "at the end of winter, an additional round of inspections and testing should be performed and an evaluation made of freeze protection performance in order to identify potential improvements, required maintenance, and freeze protection component replacement for the following winter season."[274] NERC's Reliability Guideline recommends that "after a severe winter weather event, entities should use a formal review process to determine what program elements went well and what needs improvement. Identify and incorporate lessons learned . . ."[275]

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[273] 2011 Report, Appendix: Impact of Wind Chill, p. 2 of 2.
[274] 2011 report at 205 (Recommendation 14).
[275] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v3_Final.pdf#search=reliability%20guidelines at 3.

NERC's 2014 Polar Vortex Review recommended that entities "continue to follow the Reliability Guideline."[276]

The newly-revised Reliability Standard EOP-011-2 (effective April 1, 2023) lacks any corrective action process requirement for freeze-related issues, but PRC-004-6 R5 provides a model by requiring a corrective action plan (CAP) in response to protection system failures. The PRC-004-6 R5 model could be adapted to freeze-related issues associated with generating unit outages, derates or failure to start. This Key Recommendation does not go as far as requiring evaluation of all generating units' performance at the end of winter or at the end of a severe winter event. Rather, it focuses only on the generating units that actually experienced an outage, derate or failure to start due to freezing. This focus is justified as freezing components have been one of the top causes in three grid events involving firm load shed (including the Event) and one near-miss (the 2018 event) in the past ten years.

Key Recommendation 1e: To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training. (Winter 2022-2023)

Since 2011, FERC, NERC and Regional Entities have recognized the importance of training for winterization/winter preparedness. The 2011 Report recommended that "each [GO/GOP] should develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training,"[277] while the Reliability Guideline similarly recommends "annual training in winter specific and plant specific awareness and maintenance . . .."[278] Newly-revised EOP-011-2, R8 (effective April 1, 2023) added a requirement that GOs and GOPs "identify the entity responsible for providing generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7." However, it does not require that the training occur annually. This Key Recommendation simply repeats the prior recommendations for annual training, recognizing the importance of regular training, and would revise EOP-011-2, R8 to require annual training.

Responses from the GOs/GOPs involved in the Event show that annual training is not yet universal in the Event Area. In ERCOT, despite two prior cold weather events leading to firm load shedding (1989 and 2011), 14 percent of generating units still did not provide any information about operator training programs. Seven percent of the generating units reporting outages in MISO South and 24 percent of the generating units reporting outages in SPP did not provide any evidence of a training program upon request.

Key Recommendation 1f: To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them, to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified

[276] Polar Vortex Review at 19.
[277] Recommendation 18, at 208.
[278] Reliability Guideline at 5.

ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.[279] (Winter 2022-2023)

Recommendation 12 of the 2011 report suggested that "[c]onsideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available, factoring in accelerated heat loss due to wind speed."[280] In a similar vein, the Reliability Guideline recommends that "entities review the winter cold weather temperature design basis for their generating units to determine if improvements are needed."[281] Those voluntary recommendations do not appear to have been implemented. Not only did generating units fail to perform at the lowest recorded ambient temperature for the nearest city, but many failed to perform at their own ambient design temperatures.[282]

The simple fact is that the BES cannot operate reliably without adequate generation. When, as during the Event, massive numbers of generating units fail during cold temperatures, eventually grid operators must shed firm customer load to prevent uncontrolled load shedding and cascading outages. These firm load shedding events during cold temperatures are not just another transmission system mitigation technique—they have very real human consequences. Millions went without heat, lights, refrigeration, and water for days during the Event. Hundreds died from hypothermia or trying to keep warm, in their homes, in their beds. Preventing another event like this begins with ensuring enough generating units will be available during the next cold weather event, and that means generating units need to be modified/retrofitted to perform under the adverse winter weather conditions that have been experienced at its location. While not seeking to require any new generation, this Key Recommendation also means that any future generating units that are built should be designed to perform under the same adverse weather conditions. *See also* Key Recommendation 2 regarding compensation for these investments.

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279 The Standards Drafting Team can decide what additional specificity is desirable for this requirement, for example, specifying the number of years of weather data to be considered in establishing the required ambient temperature and weather conditions, and the source of the extreme temperature and weather data.
280 2011 Report at 204.
281 Reliability Guideline, Recommendation #9, at 20.
282 *See* Recommendation 1c. Many outages in the Polar Vortex event, including a number of those in the southeastern United States, were also the result of temperatures that fell below the plant's design basis for cold weather. Polar Vortex Review at 2.

<u>Key Recommendation 1g</u>: To provide greater specificity about the relative roles of the Generator Owner, Generator Operator, and Balancing Authority in determining the generating unit capacity that can be relied upon during "local forecasted cold weather" in TOP-003-5: [283]

- **Based on its understanding of the "full reliability risks related to the contracts and other arrangements [Generator Owners/Generator Operators] have made to obtain natural gas commodity and transportation for generating units,"**[284] **each Generator Owner/Generator Operator should be required to provide the Balancing Authority with data on the total percentage of the generating unit's capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather."**
- **Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of total generating capacity that it can rely upon during the "local forecasted cold weather," and share its evaluation with the RC.**
- **Each Balancing Authority should be required to use its calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Real-time monitoring,"**[285] **and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans.**[286] **(Winter 2023-2024)**

TOP-003-5 R1 and R2 (effective April 1, 2023) will require TOPs and BAs, respectively, to include in their data specifications to the GO requests for information "during local forecasted cold weather" about generating units' operating limits, including "capability and availability; fuel supply and inventory concerns; fuel switching capabilities; and environmental constraints," as well as minimum temperature, based on one of three options.[287] A related requirement, EOP-011-2 R7.3 (also effective April 1, 2023), will require GOs to develop cold weather preparedness plans which include, at a minimum, their generating unit(s)' cold weather data such as the aforesaid capability, fuel supply concerns, environmental constraints, etc. The intent behind requiring GOs to identify and share with the BAs and TOPs the expected limitations of their generating units "during local

[283] TOP-003-5, R2.3 (Operational Reliability Data) is part of the Reliability Standards approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021). Under TOP-003-5, the Balancing Authority maintains a data specification, which is a list of data it requires from other entities, such as the Generator Owners and Generator Operators, to perform its analysis and real-time monitoring. As part of its data specification directed to Generator Owners and Generator Operators, the Balancing Authority is required to include "provisions for notification of [the generating unit's] status during local forecasted cold weather," including operating limits based on several factors and the unit's minimum temperature.

[284] Recommendation 8, below. Recommendation 8, while not a Reliability Standards revision, is a necessary complement to Key Recommendation 1g.

[285] TOP-003-5, R2.

[286] EOP-011-2, R2.2.3.2.

[287] TOP-003-5 R1.3.1, internal numbering omitted, and 1.3.2 paraphrased (the three options are design temperature, historical operating temperature, or temperature determined by an engineering analysis).

forecasted cold weather," is to prevent grid operators from being surprised when large numbers of generating units that had committed to run are unable to do so during cold weather events.

This Key Recommendation takes the next logical step and attempts to eliminate doubt about which entity is responsible to provide information or act on information. In the Event and other past cold weather events, GOs/GOPs/(QSEs in ERCOT) provided overly-ambitious projections about the ability of generating units to perform during cold weather events. As a result, the BAs and RCs were at times left with the responsibilities to serve load and manage the transmission system, respectively, without sufficient generation to serve load or support grid transfers, voltage, etc. To prevent recurrence of those scenarios, this Key Recommendation aims to assign each grid actor specific roles to avoid surprises as much as possible.

Key Recommendation 8, below, which is not a Reliability Standards change, recommends that GOs/GOPs understand the "full reliability risks related to the contracts and other arrangements they have made to obtain natural gas commodity and transportation for generating units." Using that understanding, the GO/GOP would then calculate the percentage of the generating unit's total capacity that the GO/GOP reasonably believes it can provide to the BA so that the BA can rely upon it, taking into account the "local forecasted cold weather" as well as the "full reliability risks related to their [fuel] contracts and other arrangements." So, for example, if a GOP knows that it has non-firm natural gas commodity and transportation, and that its generating units are almost always interrupted in favor of local heating load during cold weather events, the percentage of its capacity that the GO/GOP would provide the BA may be close to zero. Another GO/GOP with a dual-fuel unit that has seldom failed during a cold weather event may appropriately provide a much higher percentage of its capacity to the BA. The purpose of this Key Recommendation is not to provide a strict liability number, whereby the GO/GOP has violated the Standard unless it operates at the exact percentage predicted, but rather to transmit a good-faith, reasonable estimate, based on the information GOs/GOPs have about their historical temperature capability, fuel limitations, environmental limitations, and contractual provisions for fuel.

The BA would then consider the GOs'/GOPs' projections for their generating units, combined with the BA's experience with those generating units, the natural gas pipelines serving those generating units, and the weather predictions it is relying on for its load forecasting—to calculate the percentage of total generating capacity that it can rely upon during the "local forecasted cold weather." The BA would then share the percentage of total generating capacity that it believes it can rely upon with the RC. As with the GOs/GOPs, the goal of this Key Recommendation is not for the BA to provide a number for which it is held strictly liable, but rather a reasonable, good-faith number based on its historical experience as well as the data provided by the GOs/GOPs. While these projections will surely not be perfect, they will be better than the day-ahead commitments relied upon during the Event and in 2011. The BA and RC can then use these tempered expectations for generating units to perform their respective grid operations, including the important BA responsibilities highlighted in the last bullet above—real-time monitoring and managing generating resources as part of its capacity and energy emergency operating plans.

<u>Key Recommendation 2</u>**: Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions (or designing any new units they may build) through markets or through cost recovery approved by state public utility commissions (e.g., as a reliability surcharge) to be included in end users' service rates. The applicable ISOs/RTOs (market operators)**

and/or public utility commissions should identify how best to ensure Generator Owners have the opportunity to be compensated for making these infrastructure investments. (Winter 2022-2023)[288]

The 2011 Report recommended that when GOs build new generating units, they should be designed to operate to the lowest ambient temperature. The Report also recommended that existing generating units be retrofitted to operate to the lowest ambient temperature. At the time, GOs resisted implementing those and other recommendations, questioning how they would recover the costs of those improvements, and at least one market operator recognized that generators might need to be compensated for the additional costs of preparing for extreme cold events.[289]

In April 2021, analysts from the Dallas Federal Reserve Bank considered a Value of Lost Load (VOLL) analysis as a proxy for the damages caused by the Event. Using 2019 data for gross domestic product, electricity consumption and retail prices, they reached an average VOLL of $6,733 per megawatt hour (MWh) for firms and $117.60 per MWh for households. Using an average MW outage of 14,000 and a duration of 70.5 hours, they estimated the total VOLL for the Event at $4.3 billion (conservative compared to some of the other estimates of Event damages mentioned by the Dallas Fed—e.g., $10 to $20 billion of insurance costs, $80 to $130 billion of direct and indirect costs). But even using only the VOLL figure, the analysts argued that prevention measures costing up to $430 million per year are cost effective (assuming that severe cold weather events happen once every ten years).[290] These calculations do not, and cannot, accurately place a value on the lives lost. It is time to consider whether the markets or public utility commissions can encourage the GOs to prepare their units to perform at the temperatures experienced during the Event and in 2011. This Key Recommendation does not ask market operators and public utility commissions to make market design changes or add surcharges to end-use-customers' utility bills without obtaining data, testimony or other support for the arguments made in 2011. It only recommends that the market operators and public utility commissions consider the issue and if the GOs convince them that they cannot make these infrastructure investments otherwise, that they provide opportunities for the GOs to be compensated.

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288 Implementation for Key Recommendation 2 means that the applicable ISOs/RTOs and/or public utility commissions have begun the appropriate proceedings to consider how best to ensure Generator Owners have the opportunity to be compensated for the costs of retrofitting existing units, or designing any new units they may build to operate to specified ambient temperatures and weather conditions.

289 (*See*, *e.g.,* Comments filed in response to Project 2013-01 Cold Weather [Comments_Received_2013-01_102412.pdf (nerc.com)], ("market operators may be better equipped to address the cost of winterization into their market rules"); ("the cost impact for this project will not be insignificant. Even though it may be another 30 years before a winter event of this magnitude takes place. . . . the goal would be to quantify the reliability benefits so that they always outweigh the cost – so that we may apply our scarce dollars to other programs just as important); ("market operators should address the cost of winterization into their market rules, based on the expectations the state utilities commission has of the market operator for serving firm load," "reasonably, the market operator would develop a compensation mechanism for assuring that generators would be available under certain stressful climatic conditions," "there may need to be a compensation mechanism developed for generators that are expected to operate without failure in an extreme cold weather event.")

290 Cost of Texas' 2021 Deep Freeze Justifies Weatherization - Dallasfed.org

<u>Key Recommendation 3</u>: [291] **In the interim before the Reliability Standards revisions approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021), become effective, FERC, NERC and the Regional Entities should host a joint technical conference to discuss how to improve the winter-readiness of generating units (including best practices, lessons learned and increased use of the NERC Guidelines). Participants could include entities from cold weather regions throughout the ERO, Generator Owners/Generator Operators that operated during the entire Event or performed well in other cold weather events, Regional Entity staff who perform winterization audits, wind turbine manufacturers (to discuss winterization packages), and manufacturers of winterization equipment for other types of generation. (Winter 2022-2023)**

The Reliability Standards revisions to EOP-011, IRO-010 and TOP-003 (versions -2, -4 and -5, respectively) (effective April 1, 2023) will, for the first time, require GOs to implement and maintain cold weather preparedness plans for their generating units, which plans must include, among other things, freeze protection measures, annual inspection and maintenance of freeze protection, and cold weather capability information about the generating unit. GOs and GOPs are also required to identify the responsible party for training operations or maintenance staff on the cold weather preparedness plan. However, these improvements will not take effect until the winter of 2023/2024. In the two winters before they take effect, the danger of another severe cold weather event that could again hobble generating unit capacity remains. A recent study connected the Event to global-warming-induced weather anomalies that are likely to continue to produce severe winter storm events.[292] This Key Recommendation urges Commission staff, NERC and the Regional Entities to educate GOs and GOPs about changes they can make now to better perform during extreme cold weather events. The Team also strongly encourages GOs and GOPs to voluntarily implement the Reliability Standards revisions in advance of their effective date.

<u>Key Recommendation 4</u>:[293] **In following EOP-011-2, R7,[294] Generator Owners' plans should specify times for performing inspection and maintenance of freeze protection measures, including at a minimum, the following times: (1) prior to the winter season, (2) during the winter season, and (3) pre-event readiness reviews, to be activated when specific cold weather events are forecast. (Winter 2022-2023)**

The Texas PUC's regulations and ERCOT's Nodal Protocols contain requirements for generating units to have and adhere to winterization plans. Despite these requirements, about 82 percent of GOs/GOPs that submitted a declaration of preparation for winter to ERCOT had at least one generating unit with an unplanned outage or derated due to freezing issues during the Event. A weakness of the ERCOT approach is that there are neither minimum requirements for winterization

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291 Recommendation 7 in the September 23 Presentation.
292 Judah Cohen et al., *Linking Arctic variability and change with extreme winter weather in the United States,* 373 Sci. 1116, 1120 (2021); [Linking Arctic variability and change with extreme winter weather in the United States (science.org)]
293 Formerly Key Preliminary Recommendation 8 in the September 23 Presentation.
294 Part of the Reliability Standards revisions approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021), requires GOs' cold weather preparedness plans to address inspection and maintenance of freeze protection measures.

plans nor any deadline by which all winter preparations should be completed. Key Recommendations 1a and 1b covered the identification and protection of critical components. Key Recommendation 4 recognizes an element frequently seen in strong winterization plans: multiple inspections and frequent maintenance of freeze protection measures once they have been installed. At a minimum, Key Recommendation 4 would require inspection of freeze protection measures such as heat tracing prior to the winter season, during the winter season (the Standards Drafting Team should consider how often—perhaps monthly), and prior to a cold weather event, at a time when the weather forecast has narrowed enough to take concrete actions such as erecting temporary windbreaks or shelters, positioning heaters or draining equipment prone to freezing.

B. Natural Gas Infrastructure Cold Weather Reliability and Joint Preparedness with Bulk Electric System for Winter Peak Operations

Key Recommendation 5:[295] **Congress, state legislatures, and regulatory agencies with jurisdiction over natural gas infrastructure facilities should require those natural gas infrastructure facilities to implement and maintain cold weather preparedness plans, including measures to prepare to operate when specific cold weather events are forecast. (Winter 2022-2023)**

Key Recommendation 6:[296] **In preparing for winter weather conditions, natural gas infrastructure facilities should implement measures to protect against freezing and other cold-related limitations which can affect the production, gathering and processing of natural gas. Those measures could include, but are not limited to:**

- **implementing specific measures to directly protect vulnerable components against freezing, including**
  - **hydrate suppression chemicals/methanol injections,**
  - **burial of flow lines,**
  - **covering/sheltering sensitive facilities,**
  - **heat tracing, and/or**
  - **temporary/permanent heating equipment;**
- **ensuring necessary emergency staffing (may be known as surge capacity), including**
  - **manning key facilities 24/7 during extreme conditions,**
  - **reallocating staff to key facilities, and/or**
  - **increasing staff in the field as well as at the control center;**
- **developing mutual assistance programs, whereby fellow natural gas infrastructure entities that are not affected by the same storm could supply equipment, supplies or staff, to natural gas infrastructure entities affected by a cold weather emergency;**
- **addressing issues related to reliability of electric power, including:**

[295] Formerly Key Preliminary Recommendation 3 in the September 23 Presentation.
[296] Formerly Key Preliminary Recommendation 4 in the September 23 Presentation.

  - **reviewing electric power supply contracts to understand whether the natural gas infrastructure facility has firm or interruptible electrical power (critical natural gas infrastructure loads should not purchase interruptible electric power),**
  - **reviewing whether all electrical equipment has been designated as critical load, and/or**
  - **installing backup generation (of adequate size) at critical sites, and/or**
  - **taking proactive steps to procure quick turnaround on requests for environmental waivers for backup generators;**
- **ensuring sufficient inventory of critical spare parts, consumables, equipment, and supplies**;
- **establishing lines of communication with downstream entities, power providers, customers, and state regulators so that contact information and relationships are already established when needed during emergencies;**
- **enhancing emergency operations plans to incorporate specific extreme cold weather response elements;**
- **conducting training and drills about emergency operations plans, including coordinated drills/exercises with other natural gas infrastructure entities;**
- **ensuring physical access to key facilities, including:**
  - **coordination with state/local authorities, law enforcement or third-party contractors to prioritize organizations' activities for ensuring physical access,**
  - **road clearing/plowing and salting/deicing,**
  - **awareness of/updating easements to ensure access to leased facilities in emergencies, and/or**
  - **winterizing some or all of the vehicle fleet used for servicing critical natural gas infrastructure;**
- **managing fluids during extended cold weather events, including pre-draining storage tanks prior to an event, adding additional storage/frac tanks, storage pools, and production water gathering systems; and/or**
- **increasing capacity and resilience of saltwater disposal systems to avoid production shut-ins. (Winter 2022-2023)**

Key Recommendations 5 and 6 respond to the many natural gas production (including gathering), processing, and, to a lesser extent, pipeline, facilities adversely affected during the Event. While ideally, as in Key Recommendation 5, natural gas infrastructure entities would be legally obligated to prepare for cold weather, Key Recommendation 6 includes multiple practices that natural gas infrastructure entities can voluntarily implement. Some are long-term solutions, such as burying flow lines or adding production water systems, while others can be implemented relatively quickly, in the time between when a cold weather event is predicted and when it begins. Measures that can be quickly implemented include obtaining a backup emergency generator, pre-draining storage tanks, or manning key facilities around-the-clock. Taken together, they provide a good checklist for natural gas infrastructure owners interested in improving their performance when a similar cold weather event occurs. The Team includes some pipeline-related measures because, although natural gas pipelines were not tested in the Event as severely as in 2011, due to the record reductions in production of natural gas as well as the unprecedented numbers of natural gas-fired generating units that failed to perform, in another cold-weather event, they could again face conditions more similar to 2011, in which several LDCs curtailed gas service to retail customers.[297]

Key Recommendation 7:[298] **FERC should consider establishing a forum in which representatives of state legislatures and/or regulators with jurisdiction over natural gas infrastructure, in cooperation with FERC, NERC and the Regional Entities (which collectively oversee the reliability of the Bulk Electric System), and with input from the Balancing Authorities (which are responsible for balancing load and available generation) and natural gas infrastructure entities, identify concrete actions (consistent with the forum participants' jurisdiction) to improve the reliability of the natural gas infrastructure system necessary to support the Bulk Electric System. Options for establishing the forum could include a joint task force with NARUC, a Federal Advisory Committee, or FERC-led technical conferences. Ideally, the forum participants will produce one or more plans for implementing the concrete actions, with deadlines, which identify the applicable entities with responsibility for each action. At such a forum, topics could include:**[299]

- **Whether and how natural gas information could be aggregated on a regional basis for sharing with Bulk Electric System operators in preparation for and during events in which demand is expected to rise sharply for both electricity and natural gas, including whether creation of a voluntary natural gas coordinator would be feasible;**
- **Whether Congress should consider placing additional or exclusive authority for natural gas pipeline reliability within a single federal agency, as it appears that no one agency has responsibility to ensure the systemic reliability of the interstate natural gas pipeline system;**
- **Additional state actions (including possibly establishing an organization to set standards, as NERC does for Bulk Electric System entities) to enhance the reliability of intrastate natural gas pipelines and other intrastate natural gas facilities;**
- **Programs to encourage and provide compensation opportunities for natural gas infrastructure facility winterization;**
- **Which entity has authority, and under what circumstances, to take emergency actions to give critical electric generating units pipeline transportation priority second only to residential heating load, during cold weather events in which natural gas supply and transportation is limited but demand is high;**

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[297] 2011 Report at 126-135.
[298] Formerly Key Preliminary Recommendation 5 in the September 23 Presentation.
[299] The Team is not advocating for the specific implementation of any specific action on any of these topics; rather, this Recommendation envisions that the entities with the most control over, and those most affected by, the natural gas reliability issues that have repeatedly arisen during cold weather events will convene and identify potential solutions. For example, the Team is not advocating that all generating units need to obtain firm natural gas supply or transportation contracts, but that entities convene to identify possible solutions to issues surrounding natural gas-fired generating units that do not have firm natural gas supply or transportation contracts.

- **Which entity has authority to require certain natural gas-fired generating units to obtain either firm supply and/or transportation or duel fuel capability, under what circumstances such requirements would be cost-effective, and how such requirements could be structured, including associated compensation mechanisms, whether additional infrastructure buildout would be needed, and the consumer cost impacts of such a buildout;**
- **Expanding/revising natural gas demand response/interruptible customer programs to better coordinate the increasing frequency of coinciding electric and natural gas peak load demands and better inform natural gas consumers about real-time pricing;**
- **Methods to streamline the process for, and eliminate barriers to, identifying, protecting, and prioritizing critical natural gas infrastructure load;**
- **Whether resource accreditation requirements for certain natural gas-fired generating units should factor in the firmness of a generating unit's gas commodity and transportation arrangements and the potential for correlated outages for units served by the same pipeline(s);**
- **Whether there are barriers to the use of dual-fuel capability that could be addressed by changes in state or federal rules or regulations. Dual-fuel capability can help mitigate the risk of loss of natural gas fuel supply, and issues to consider include facilitating testing to run on the alternate fuel, ensuring an adequate supply of the alternate fuel and obtaining the necessary air permits and air permit waivers. The forum could also consider the use of other resources which could mitigate the risk of loss of natural gas fuel supply;**
- **Electric and natural gas industry interdependencies (communications, contracts, constraints, scheduling);**
- **Increasing the amount or use of market-area and behind-the-city-gate natural gas storage; and**
- **Whether or how to increase the number of "peak-shaver" natural gas-fired generating units that have on-site liquid natural gas storage. (Winter 2022-2023)**

This Key Recommendation proposes a forum to address the problem that the reliability of the BES depends, in large part, on the reliability of the natural gas infrastructure system, but unlike the BES, with its mandatory Reliability Standards enforced by FERC and NERC, the reliability of the natural gas infrastructure system rests largely on voluntary efforts. In February 2021, millions of Americans were dependent upon natural gas not only to heat their homes, but also to provide the fuel for the generating units that would provide the energy to light their homes and energize their furnaces (so they could use the natural gas that heats their homes). During the Event, natural gas fuel supply issues were the second-largest cause of generating unit outages that left residents without heat and light and energy in ERCOT for nearly three days, during freezing temperatures.

The idea of a forum in which "representatives of the electric and natural gas industries operating in the region, as well as the regulatory bodies overseeing them," can meet to discuss and cooperate on gas-electric interdependence, is not new. That language, while not from a recommendation, is taken directly from a discussion in the 2011 Report of how to address fuel switching issues.[300] The 2011 Report devoted an entire section to electric and natural gas interdependencies. The 2011 Report recognized that falling natural gas prices as a result of shale gas technological advances led to natural gas becoming an increasingly popular fuel choice for generating units, while compressors used in the production and transportation of natural gas increasingly relied on electricity instead of natural gas.[301]

Despite the actions taken before and after the 2011 event (discussed in more detail below), natural gas-electric infrastructure interdependencies remain unsolved.[302] The Event showed that natural gas-fired generating units were, in many cases, dependent on natural gas production facilities for natural gas supply, but many of them were unable to produce, leaving many units without natural gas even when natural gas pipeline facilities performed as well as could be expected. Natural gas production facilities are almost entirely intrastate and unregulated. NERC's 2021 Reliability Risk Priorities Report,[303] intended to identify the key risks to the BES,[304] identifies "critical infrastructure interdependencies, such as the ability to deliver natural gas to generating units supporting reliability" as one of the top four risks.[305]

The Team believes that the time has come for a concerted effort among those who can address the natural gas-electric infrastructure interdependency problem to consider the topics set forth above, or other topics of their own choosing.[306] With severe cold weather events forecasted to increase,[307] society can no longer afford to view occurrences like the Event and the 2011 event as "black swan events"[308] that are unlikely to reoccur. BAs and RCs should no longer be forced to serve load and

300 2011 Report at 194.
301 2011 Report at 189.
302 A few ISOs/RTOs have implemented "pay for performance" constructs. For example, PJM has a "Capacity Performance" program, in which "generators may receive higher capacity payments and *are expected in return to invest* in modernizing equipment, firming up fuel supplies and adapting to use different fuels." https://pjm.com/-/media/markets-ops/rpm/review-of-october-2019-performance-assessment-event.ashx at 2 (emphasis added). Generators receiving the higher capacity payments that do not perform during one of the Performance Assessment Intervals, can be penalized. While intended to encourage such investments, Generator Owners are not required by pay-for-performance rules to obtain firm gas commodity or transportation contracts.
303 *See* https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf
304 *Id.* at 5.
305 *Id.* at 32-33.
306 This Recommendation is related to Recommendation 24, which suggests that the same entities involved in the forum study and enact measures "to address natural gas supply shortfalls during extreme cold weather events." The topics included in Recommendation 24 were those the Team viewed as requiring additional study before they might be ready for discussion in the forum, however, forum participants should feel free to consider any topic from Recommendation 24 in addition to those included in this Recommendation, or to refer any topic from this Recommendation for further study.
307 Judah Cohen et al., *Linking Arctic variability and change with extreme winter weather in the United States,* 373 Sci. 1116, 1120-1121 (2021); https://www.science.org/doi/10.1126/science.abi9167. The authors also identify a precursor condition that, if identified by forecasters, could provide more warning before future extreme cold weather events in warm-weather areas like the Event. 373 Sci. at 1122 and Figure 2.
308 From the book of the same name by Nicholas Taleb, black swan events refer to rare and unpredictable outlier events. https://en.wikipedia.org/wiki/The_Black_Swan:_The_Impact_of_the_Highly_Improbable

operate the grid during these events under conditions beyond anything ever intended, studied, or trained for.

The Team has proposed several options for how the natural gas infrastructure entities, grid entities and those with power to regulate these entities, as well as NERC and its Regional Entities, can convene to tackle the natural gas-electric infrastructure interdependency puzzle. Each option has its benefits and potential drawbacks, which are set out in the table below. On balance, while the Federal Advisory Committee would require more effort to convene, it best fits the need to allow a group of disparate representatives from multiple industries, and multiple state and federal regulators (or those who have authority to regulate but have not exercised it, such as Congress and some state legislatures), to address a thorny problem over time, with the assistance of experts as needed. This Key Recommendation is not meant to be prescriptive as to the method used or topics addressed--if the affected sectors, entities, regulatory agencies, and other regulators can find another forum to accomplish the same objectives, the Team would welcome that approach.

Forum	Description	Benefits	Potential Drawbacks
Federal Advisory Committee[309]	Chairman of the Commission can create a committee which can include non-Federal employees (such as state regulators, industry representatives, NERC, Regional Entity and NARUC, etc.)	-allows for committee to continue to meet until purpose is accomplished, then committee will end -committee can hire experts if needed -allows public participation at most meetings -committee members can be compensated for their time if needed -federal employees can be assigned to work for the committee without losing pay or benefits	-requires consultation with Secretariat of the General Services Administration and public notice in the Federal Register before establishing committee -recordkeeping requirements for Commission, including drafting a charter - the committee is legally required to provide advice to the Commission, not other entities, although scope of issues to be addressed is broader than Commission's jurisdiction.

[309] Federal Advisory Committee Act, §7(c), 5 U.S.C.A. App. 2 (2018); regulations found at GSA Regulations, Part 102-3, §102-3.5 *et. al.* (2021) (Federal Advisory Committee Management), https://www.gsa.gov/policy-regulations/regulations/federal-management-regulation-fmr/idtopicx2x1678#idtopicx2tex1688.

FERC-led Technical Conferences	One or more technical conferences similar to the ones conducted in 2012 as described above—would include filed written testimony, public hearings with testimony; technical conference testimony is often used as the factual basis to support later Commission action such as Notice of Proposed Rulemaking.	-fully within FERC's jurisdiction without any additional permission or recordkeeping -long-established procedures, familiar to electric and interstate gas pipeline sectors -allows for public participation	-FERC may have reached the limits of what can be accomplished via this method for the gas-electric coordination issue—see past history below. -limited duration—normally a day or series of days of testimony plus written filed testimony -not ideally-suited for a series of ongoing meetings among representatives from natural gas and electric sectors as well as their regulators or potential regulators -regulations do not specifically allow for compensating participants or experts -does not allow for members of other federal agencies to work on the project, as does the forum, while maintaining salary and benefits
Joint FERC-NARUC Technical Conference(s)	Similar to FERC-led Technical Conference, but with cooperation between FERC and NARUC[310] in	-same procedural benefits as FERC-led Technical Conference(s)	-same potential drawbacks as FERC-led Technical Conferences

[310] National Association of Regulatory Utility Commissioners. Home - NARUC

	planning and execution	-NARUC leadership and staff participation -NARUC expertise with state regulatory issues and intrastate gas and electric infrastructure -access to NARUC's contacts and relationships with state regulators and industry participants	

The Commission and NERC have already taken actions within their respective areas of authority to address gas-electric interdependency issues, but some aspects of the problem are either outside their authority or require cooperation among jurisdictions. After the 2011 event,[311] the Commission initiated a proceeding (Docket No. AD12-12-000) in early 2012, requesting comments on questions about topics including market structure and rules, scheduling, communications, infrastructure, and reliability.[312]

The Commission received comments from 79 entities and convened five regional conferences in Docket No. AD12-12-000[313] for the Central, Northeast, Southeast, West and Mid-Atlantic regions throughout the month of August 2012, in advance of the winter heating season, to solicit input from both industries regarding the coordination of natural gas and electricity markets. A cross-section of industry representatives participated in the docket and/or attended the conferences, which were structured around three sets of issues: scheduling and market structures/rules; communications, coordination, and information-sharing; and reliability concerns.

[311] Even before the 2011 event, NERC had a Gas-Electric Interdependency Task Force, which released a 2004 report titled "Gas/Electricity Interdependencies and Recommendations." 2011 Report at 194; https://www.naesb.org//misc/nerc_gas_electricity_interdependencies_2004.pdf (focused on "gas pipeline operations and planning and electric generation operations and planning," not natural gas processing or production).

[312] *Coordination between Natural Gas and Electricity Markets*, Docket No. AD12- 12-000 (Feb. 15, 2012) (Notice Assigning Docket No. and Requesting Comments) (available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=01CF0351-66E2-5005-8110-C31FAFC91712). The topics were based on questions raised by then-Commissioner Moeller in a statement. Commissioner Philip D. Moeller, Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets (Feb. 28, 2012), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20120228-4005.

[313] *Coordination between Natural Gas and Electricity Markets*, Docket No. AD12- 12-000 (July 5, 2012) (Notice of Technical Conferences) (available at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13023450); 77 Fed. Reg. 41,184 (July 12, 2012) (available at http://www.gpo.gov/fdsys/pkg/FR-2012-07- 12/pdf/2012-16997.pdf).

As a result of the conferences, the Commission received valuable feedback which resulted in two orders that removed roadblocks to gas-electric cooperation. First, in Order No. 787,[314] the Commission addressed fears that the Standards of Conduct prohibited communication between electric utilities and pipelines. The order revised Commission regulations to explicitly authorize interstate natural gas pipelines and public utilities to share nonpublic operational information for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system. While authorizing certain beneficial information sharing, FERC also established a "no conduit rule," which prohibits public utilities and pipelines—as well as their employees, contractors, consultants, and agents—from disclosing—or using anyone as a conduit for disclosure of—nonpublic, operational information that they receive under this rule to a third-party or to its marketing function employees. Finally, the order included additional protections to ensure that shared information remains confidential.

Second, in Order No. 809,[315] the Commission helped harmonize natural gas interstate pipeline transportation and the gas day with the needs of natural gas-fired generating units by extending the first, and most commonly-used, day-ahead deadline for scheduling interstate transportation, and adding another scheduling opportunity during the gas day. These changes helped better align the natural gas and electric daily schedules, although differences remained, and allowed natural gas shippers to adjust their contracts to reflect changes in demand. The Final Rule provided additional contracting flexibility to firm natural gas transportation customers by allowing multi-party transportation contracts, but declined to move the start of the gas day from 9 a.m. to 4 a.m. as initially proposed. The Commission also instituted proceedings under section 206 of the Federal Power Act (FPA) to ensure that the ISOs'/ RTOs' day-ahead scheduling practices harmonized with the revisions to the natural gas scheduling practices adopted by the Commission.

Although the Commission took actions within its jurisdiction to address the issues raised during the 2012 technical conferences, some debates from 2012 continue today. For example, natural gas-fired GOs participating in the RTO/ISO markets claimed in 2012 that managing fuel procurement risk was challenging because the timeframe for nominating natural gas transportation service, including pursuant to capacity release,[316] was not synchronized with the timeframe during which generators receive confirmation of their bids in the day-ahead electric markets. On the other hand, natural gas pipelines argued that the problem was not the gas-electric day mismatch but rather the failure of the GOs/GOPs to sign up for firm capacity or firm pipeline transportation. Similar discussions continue today about why GOs/GOPs do not sign up for firm capacity or firm pipeline transportation, and what, if anything, can be done to influence that behavior. In 2012, natural gas-fired generating units told the Commission that they were not subscribing to firm transportation contracts on pipelines because their capacity use was not high enough to make the decision economic, stressing that they would not be able to recover the cost of firm pipeline transportation capacity in their dispatch prices in the competitive ISO/RTO markets. To address this concern, some natural gas pipelines told the Commission they were offering enhanced flexible firm transportation and storage services, such as no-notice service or the ability to take at a non-uniform

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[314] 145 FERC ¶ 61,134 (2013).

[315] 151 FERC ¶ 61,049 (2015).

[316] Capacity release refers to holders of firm transportation or storage rights reselling a portion of that capacity. Interstate capacity release occurs pursuant to pipeline or storage facility tariffs approved by FERC.

hourly flow rate or to allow contracts for firm rights to exceed daily scheduling limits without penalty. Still, the Commission learned that many generators were not subscribing to these services, mainly due to cost concerns.

NERC also issued two Reliability Guidelines after the 2011 event intended to increase coordination between the natural gas and electric sectors and reduce the risks associated with fuel unavailability. The first guideline, Gas and Electrical Operational Coordination Considerations,[317] provided guidance in areas including:

- establishing natural gas and electric industry coordination mechanisms,
- understanding how the gas and electric systems interface with each other and their interdependencies,
- training (which included a recommendation about joint training related to load shedding) and testing,
- establishing and maintaining open communication channels, and
- gathering and sharing information/situational awareness.

The second guideline, Fuel Assurance and Fuel-Related Reliability Risk Analysis for the BES,[318] focused on fuel supply risk analysis for all generating unit fuel sources (not just natural gas).

Fuel Switching: A Missed Opportunity?

Units capable of fuel switching have both economic and reliability benefits: allowing operators to purchase the cheaper of two fuels and have an alternate source of fuel if one source is interrupted or curtailed. In ERCOT, approximately 392 generating units reported an unplanned outage, derate or failure to start and use coal, gas, oil, waste heat or other non-renewable fuels as their primary or only fuel. About 41 of those generating units are capable of fuel switching, yet only roughly a third (14 of 41) attempted to switch from their primary fuel to their secondary fuel during the Event. Of the 14, 11 generating units were initially successful in switching fuel types (gas to distillate oil or oil), but 12 units either failed to switch (three units) or subsequently experienced outages related to their use of alternate fuels (nine units). Twenty-four generating units were capable of fuel switching but were not requested or required to switch during the Event, and the remaining three units capable of fuel switching were on planned or maintenance outages.

Approximately 86 percent (12 out of 14) generation units that attempted to switch fuel types in ERCOT failed or were subsequently outaged or derated. The majority of the units that attempted switching were gas generators switching to distillate oil or oil. Failures in fuel switching were due to problems including the blade path temperature spread from uneven burning of oil, fuel oil pump fouling, fuel oil system trip, fire in turbine enclosure due to fuel oil leak, valve failure, never operated on

[317] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Gas_Electric_Guideline.pdf
[318] *See* https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

alternate fuel, inability to synchronize on alternate fuel source due to loss of flame issues during startup, and inability to synchronize on alternate fuel source due to failure to accelerate fault during startup.

In MISO South, four entities reported owning a total of nine dual-fuel units, and one unit was asked to operate on fuel oil due to natural gas fuel restrictions. The unit used a propane system for starting and contributed up to 120 MW of generation from February 15 through February 17. In SPP, nine entities reported owning 46 units capable of fuel switching. In total, 38 units attempted to switch fuels during the Event, and 37 of 38 units successfully switched fuels. One unit failed to start on the secondary source, and one unit was asked three times, failed in one attempt to switch, and did eventually switch. Most units switched from natural gas to oil, and two units supplemented coal with natural gas. Generating units in SPP that switched fuels contributed an average of 1,300 MW of generation during the height of the Event from February 15 through February 18.

Key Recommendation 8:[319] To better provide Balancing Authorities with accurate information under TOP-003-5, R2.3.1.2 ("fuel supply and inventory concerns"), Generator Owners/Generator Operators should identify the full reliability risks related to the contracts and other arrangements they (individually or collectively)[320] have made to obtain natural gas commodity and pipeline transportation for generating units, including but not limited to volumetric terms, transportation service types, and impacts from potential force majeure clauses. (Winter 2021-2022)

This Key Recommendation seeks to ensure that natural gas-fired generating units convey to BAs the reliability of their natural gas commodity and transportation contracts, especially whether those contracts are firm or non-firm (and any volumetric limits). Such information would give a BA a better sense of the generation capacity available in its footprint during emergencies like the Event, and improve the BA's operational planning. This Key Recommendation is a necessary predecessor to Key Recommendation 1h, which apportions responsibility for estimating the likelihood of generating units being able to perform during "local forecasted cold weather" between generating units and BAs.

This Key Recommendation also will also help GOs/GOPs comply with TOP-003-5, R2.3.1.2 (effective April 1, 2023), which adds to the BA's data specification "provisions for notification of BES generating unit(s) status during local forecasted cold weather to include . . . operating limitations based on . . . fuel supply and inventory concerns." Requirement 2.3.1.2 will require BAs to ask for information about limitations based on fuel supply and inventory concerns. To prepare to respond to the BA's data specification, this Key Recommendation encourages GOs/GOPs to identify the reliability risks related to their natural gas commodity and pipeline transportation arrangements. Although TOP-003-5, R2.3.1.2 will not be effective until April 1, 2023, the Team has

319 Formerly Key Preliminary Recommendation 6 in the September 23 Presentation.

320 Arrangements to obtain natural gas commodity and pipeline transportation for generating units may vary between generator owners and generator operators. The GOs should identify the party(s) to their BAs who will be providing the information that is specified by the BA.

designated this Key Recommendation to be implemented before winter 2021-2022, and encourages GOs/GOPs to share this information voluntarily with their BAs in advance of TOP-003-5, R2.3.1.2's effective date.

During the Event, natural gas fuel supply issues impacted 357 natural gas-fired generators across the three areas; 55 percent, or 185 of 336 natural gas-fired generating units in the ERCOT footprint; 40 percent, or 31 of 77 units in MISO South; and 74 percent, or 141 of 191 units in the SPP footprint, as shown in Figure 103, below.

Figure 103: Contractual Arrangements of Natural Gas-Fired Generating Units that Experienced Outages and Derates in the Event Area

Generating Unit Natural Gas Commodity and Transportation Contracts						
	ERCOT		MISO		SPP	
	Generators	Percent	Generators	Percent	Generators	Percent
Firm Commodity/Firm Transportation	45	24%	10	32%	47	33%
Firm Commodity/Mixed Transportation	14	8%	7	23%	19	13%
Firm Commodity/Non-Firm Transportation	0	0%	0	0%	4	3%
Non-Firm Commodity/Non-Firm Transportation	26	14%	1	3%	24	17%
Non-Firm Commodity/Mixed Transportation	9	5%	0	0%	13	9%
Non-Firm Commodity/Firm Transportation	1	1%	3	10%	14	10%
Mixed Commodity/Mixed Transportation	34	18%	5	16%	0	0%
Mixed Commodity/Firm Transportation	35	19%	0	0%	0	0%
Mixed Commodity/Non-Firm Transportation	0	0%	0	0%	0	0%
Did not provide information re: commodity contract type	10	5%	0	0%	11	8%
No contract or did not provide information about transportation contract type	11	6%	5	16%	9	6%
Total	**185**	**100%**	**31**	**100%**	**141**	**100%**

As shown in Figure 103, above, the *majority* of natural gas-fired generating units experiencing outages and derates had a mixture of firm and non-firm commodity and pipeline transportation contracts or had interruptible transportation contracts for their contracted volumes. A minority of natural gas-fired generating units had both firm commodity and firm transportation contracts for all their contracted volumes. Generally natural gas-fired generating units do not contract for the full volumes of natural gas needed to run at maximum capacity. Typically, they use short-term sales or storage capacity to procure additional natural gas as needed. During the Event, some natural gas-fired generating units attempted to procure their gas commodity from alternative sources, but due to natural gas supply shortages, the majority were unable to secure additional volumes above their contracted volumes to operate at their expected capacity.

Although generating units with firm natural gas commodity and transportation contracts were not immune from outages and derates due to natural gas fuel supply issues, of the 357 natural gas-fired generating units across the three footprints that had an outage or derate due to natural gas fuel supply issues, only 29 percent had both firm natural gas commodity and firm natural gas pipeline transportation contracts for any volume, as Figure 103 shows (ERCOT, 45; MISO, 10; SPP, 47). Figure 104a, below, shows firm natural gas pipeline transportation capacity contracted, daily volumes of natural gas nominated and daily volumes of natural gas ultimately shipped. Even though the figure indicates that natural gas shipped to natural gas-fired generating units with firm interstate pipeline capacity was less than contracted volumes beginning February 10 and continuing through the Event period (outages due to natural gas fuel supply issues began in the SPP footprint on February 8, 2021), the majority of nominated natural gas was delivered to natural gas-fired generating units. Natural gas-fired generating units with interruptible transportation contracts were still able to nominate and ship some gas under those contracts, but at smaller volumes than gas shipped under firm transportation contracts. Natural gas-fired generating units that were unable to procure natural gas commodity would not have submitted a nomination for transportation. See Figure 104b for volumes nominated and shipped by natural gas-fired generating units with interruptible transportation contracts.

Figure 104a: Firm Pipeline Capacity that was Nominated, Shipped, and contracted by Natural Gas-Fired Electric Generation, February 1-28, 2021 From Sampled Pipelines in Oklahoma, Texas, Louisiana, and Kansas (Units: Dth/d)

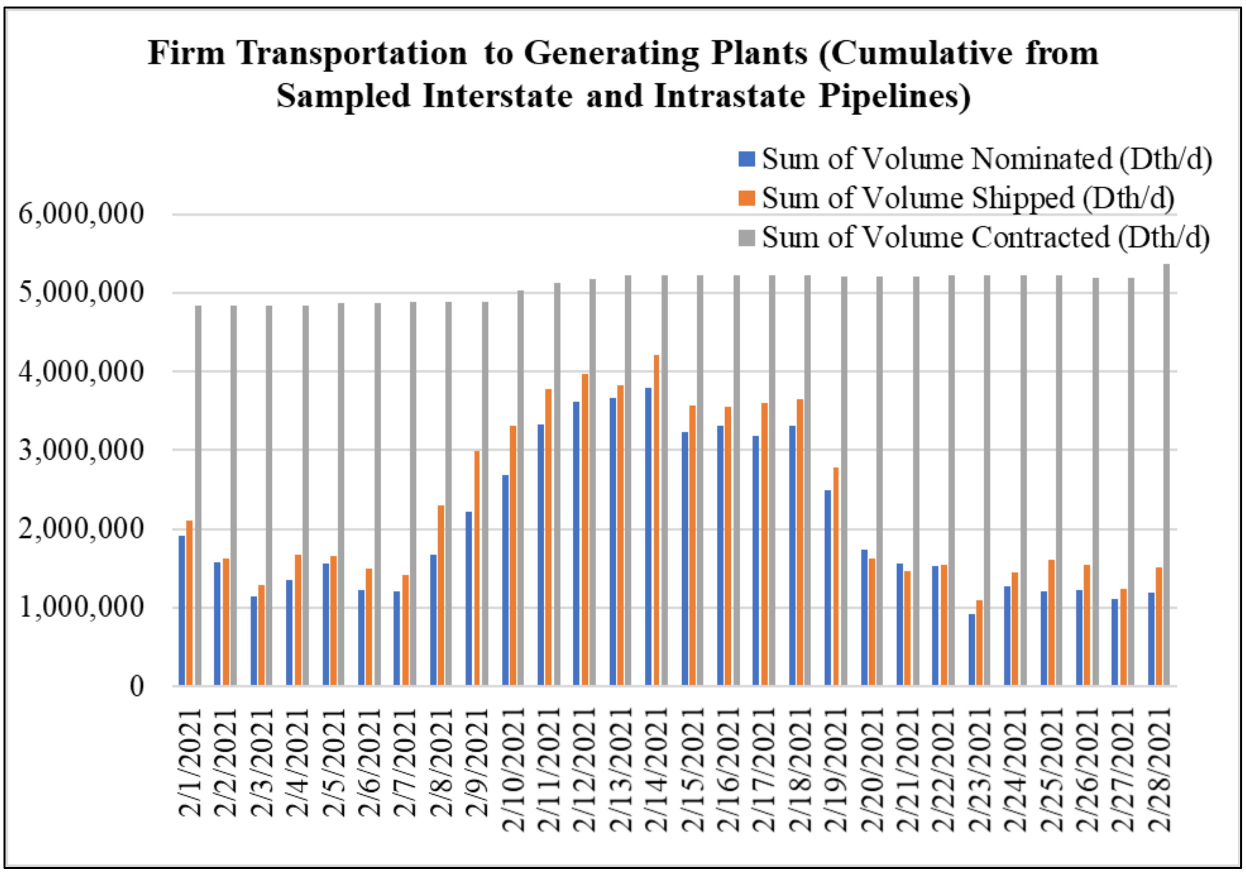
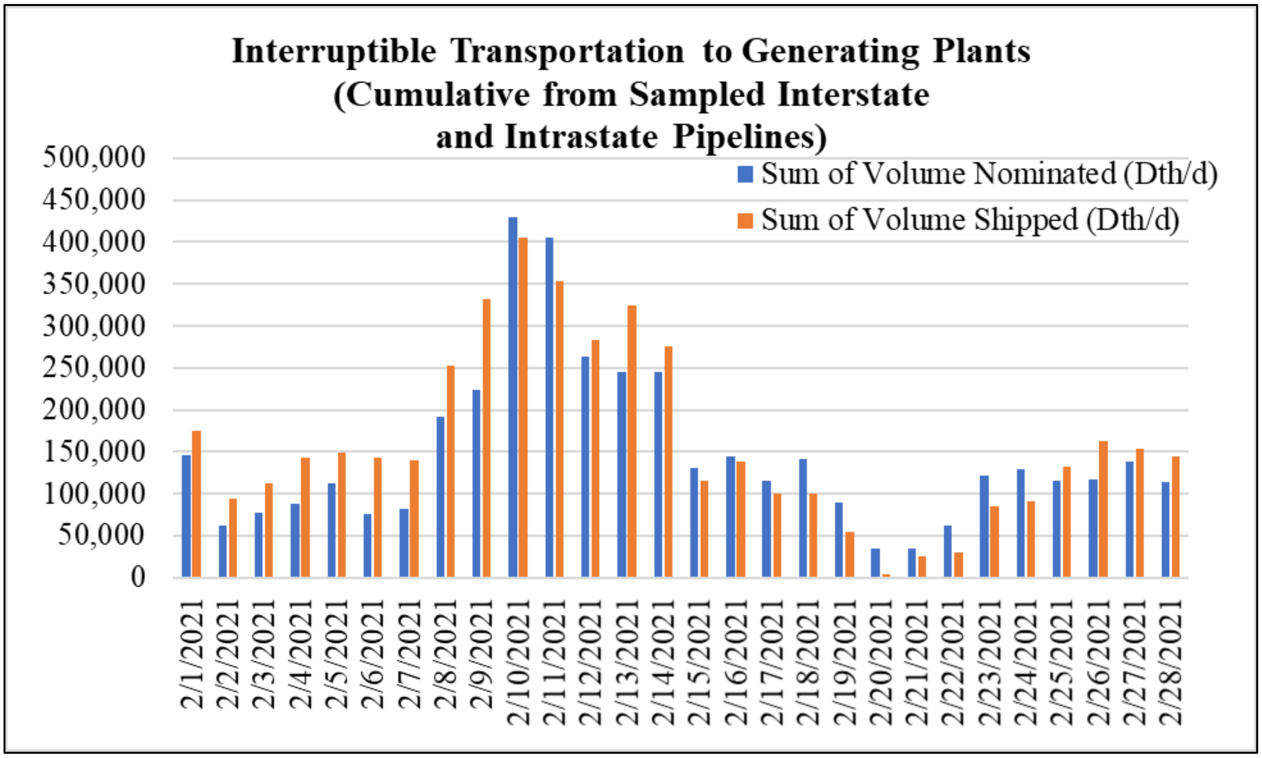


Figure 104b: Interruptible Pipeline Capacity that was Nominated by and Delivered to Natural Gas-Fired Electric Generation, February 1-28, 2021, on the Sampled Pipelines in Oklahoma, Texas, Louisiana, and Kansas (Units: Dth/d)



By assessing the terms and conditions of the commodity and transportation contracts that will be in effect during winter peak conditions for their natural gas-fired generating units, GOs/GOPs can achieve a greater understanding of the risks of natural gas fuel interruption across their fleet. GOs/GOPs can then include this information when providing their operating limitations based on fuel supply and inventory concerns to the BA, for the BA's incorporation into operational planning analyses for winter peak conditions.

C. Grid Emergency Operations Preparedness

Key Recommendation 1 (h through j): The Reliability Standards should be revised as follows:

Key Recommendation 1h: To require Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) to prohibit use for demand response of critical natural gas infrastructure loads.[321] (Winter 2023-2024)

In the Event, at least one natural gas infrastructure entity (a producer) registered what it called its "high-electric demand, low-production facilities" in ERCOT's Load Resource demand response program, which would result in its facilities being de-energized during the Event. This sampling of natural gas producers in the ERCOT area[322] led the Team to conclude that other natural gas production entities could have participated in demand response programs and been called upon to de-energize, thereby becoming unavailable and contributing to natural gas fuel supply issues during the Event. Under the Reliability Standards, a Balancing Authority has operating plans to plan for contingency reserves and to mitigate emergencies in its area, including energy emergencies.[323] These plans can rely in part on demand response programs. If the resources the BA relies upon to reduce load (in this case, ERCOT relying on Load Resources that included gas production entities) instead reduce the availability of the BAs' natural gas-fired generation, BES reliability would be harmed, and the purpose of the plan would be defeated. This Key Recommendation does not advocate for an absolute prohibition on BAs' operating plans allowing natural gas infrastructure loads to participate in demand response; rather, it limits the operating plans' prohibition to *critical* natural gas infrastructure loads which, if de-energized, would adversely affect BES natural gas-fired generation.[324] *See also* Recommendation 28, below, regarding further study of how to identify critical natural gas infrastructure loads.

Key Recommendation 1i: To protect critical natural gas infrastructure loads from manual and automatic load shedding (to avoid adversely affecting Bulk Electric System reliability):

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321 Critical natural gas infrastructure loads are natural gas infrastructure (see definition in footnote 29) loads which, if de-energized, could adversely affect provision of natural gas to BES natural gas-fired generating units, thereby adversely affecting BES reliability. *See* further study Recommendation 28 below, regarding criteria for identification of critical natural gas infrastructure loads.

322 *See* Appendix I for a discussion of the scope of the Team's natural gas production data.

323 Reliability Standard BAL-002-3 - Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event requires BAs to have an operating process as part of its operating plan to make preparations to have contingency reserves equal to or greater than the BA's most severe single contingency available for maintaining system reliability. Reliability Standard EOP-011-1 – Emergency Operations requires each BA to develop, maintain, and implement one or more Reliability Coordinator-reviewed operating plan(s) to mitigate capacity emergencies and energy emergencies within its Balancing Authority Area.

324 If a natural gas infrastructure entity owns or operates a natural gas facility that has electric loads that are *not* determined to be critical, those loads could be used as demand response and interrupted via instructions issued by the BA, to provide contingency reserves (as part of the BA's Operating Plan).

- **To require Balancing Authorities' and Transmission Operators' provisions for operator-controlled manual load shedding to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas;**
- **To require Balancing Authorities', Transmission Operators', Planning Coordinators', and Transmission Planners' respective provisions and programs for manual and automatic (e.g., underfrequency load shedding, undervoltage load shedding) load shedding to protect identified critical natural gas infrastructure loads from manual and automatic load shedding by manual and automatic load shed entities[325] within their footprints;**
- **To require manual and automatic load shed entities to distribute criteria to natural gas infrastructure entities that they serve and request the natural gas infrastructure entities to identify their critical natural gas infrastructure loads; and**
- **To require manual and automatic load shed entities to incorporate the identified critical natural gas infrastructure loads into their plans and procedures for protection against manual and automatic load shedding. (Winter 2023-2024)**

The manual load shed plans (of TOPs) and automatic underfrequency load shed plans (of TOs and DPs) within the ERCOT footprint were designed to avoid controlled power outages to priority or critical electric loads if the need to shed firm load arose. However, most of the natural gas production and processing facilities surveyed were not identified as critical load or otherwise protected from manual load shedding.[326] Thus, from early February 15 through February 18, the implementation of manual firm load shedding by ERCOT operators to preserve BES reliability partially contributed to the decline in the production of natural gas. Protecting these facilities from manual load shedding would have helped to provide natural gas supply and transportation to natural gas-fired generating units –potentially reducing the total magnitude of manual firm load shed needed by the ERCOT BA to maintain BES reliability.

<u>Key Recommendation 1j</u>**: In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners and Distribution Providers should separate circuits that will be used for manual load shed from circuits used for underfrequency load shedding/undervoltage load shedding or serving critical load. Underfrequency load shedding/undervoltage load shedding circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency). (Winter 2022-2023)**

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[325] Manual and automatic load shed entities include applicable TOPS, TOs, and DPs.

[326] According to the RRC, one reason that production facilities in Texas may have not self-identified as critical load is that a form in use prior to the Event (to apply for the status of "Load Serving Natural Gas-Fired Generation," which included gas infrastructure serving generation) stated that it was not to be used by "field services," and typically producers are considered to be "field services." Of the 32 pipelines (both interstate and intrastate) that provide data, 10 pipelines had some facilities (which included metering stations, compressor stations, and storage facilities) designated as protected or critical load. To protect pipelines from load shedding, all pipelines had backup generators/batteries at their major facilities. Thus, only a very small number of pipeline facilities were affected by the firm load shed.

Reliability Standard EOP-011-1, Requirement R2.2.8 requires provisions for operator-controlled manual load shedding that minimize the overlap with automatic load shedding and are capable of being implemented in a timeframe adequate for mitigating the emergency. ERCOT requires a minimum of 25 percent of load to be connected to UFLS circuits in three steps. Five percent of load should automatically shed at 59.3 Hz (block one), 10 percent should automatically shed at 58.9 Hz (block two), and 10 percent should automatically shed at 58.5 Hz (block three).

At times during the Event, ERCOT manual and automatic load shedding entities were forced to manually shed circuits normally reserved for automatic UFLS, due to the large amounts of load shedding ordered, the duration of the load shedding, and the circuits protected from load shedding as critical. ERCOT operators on several occasions advised TOP operators to manually shed block two of their UFLS circuits to maintain their obligation of total pro rata load shed.

There was a significant risk in ERCOT of the UFLS activating during the four minutes on February 15 when its frequency was below 59.4 Hz, and in fact, approximately 276 MW of UFLS circuits did activate. Even when a system is not as close to the edge as ERCOT was on February 15, there is always the risk that during cascading or uncontrolled load shed, every MW of UFLS will be needed, and especially the first block of UFLS, where operators have the best chance of arresting the frequency decline.

At the same time, this Key Recommendation recognizes that during dire situations like the Event in ERCOT, TOPs, TOs and DPs may not have enough non-UFLS and non-critical circuits to implement the amount of load shed directed by the BA. In such a situation, protecting system reliability requires the lesser evil of using some UFLS circuits to implement the required load shedding. However, under this Key Recommendation, the Team prefers that the TOPs, TOs and DPs start with the lowest frequency (which in ERCOT would be block three, not block two), to minimize system impacts if UFLS does activate. The Key Recommendation to draw from the third block, or last stage, of UFLS—the least likely to be needed—balances the risk of the immediate emergency need to balance generation and load to maintain reliability, with the potential for frequency disturbances in the future.

D. Grid Seasonal Preparedness for Cold Weather

Key Recommendation 9: Planning Coordinators should reconsider some of the inputs to their publicly-reported winter season anticipated reserve margin calculations[327] for their respective Balancing Authority footprints so that the reported reserve margins will better predict the reserve levels that the Balancing Authorities could experience during winter peak conditions. MISO and SPP should also improve their internal winter peak load forecasts. The suggested improvements should result in seasonal reserve margin projections which better account for resource and demand uncertainties and align better with each Balancing Authority footprint's near-term planning during forecast cold weather events. Planning Coordinators should reconsider the following components of winter reserve margins:

[327] *See* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf.

a. **ERCOT, SPP, MISO (for MISO South) and other Planning Coordinators that forecast load within southern states should adjust their 50/50 forecasts to reflect actual historic peak loads that occurred during severe cold weather events in their footprints, and reflect the potential for exponential load increase due to the resistive heating used in southern states;**
b. **Planning Coordinators should revisit how much natural gas-fired generation should be considered as capacity to be included in winter season anticipated reserve margin calculations and projections;**
c. **Planning Coordinators should revisit how much wind[328] generation should be considered as capacity and included in winter reserve margin calculations and projections;**
d. **MISO should perform a winter peak analysis for each MISO sub-zone (focusing on MISO South) to improve its winter peak load forecast. MISO should use actual prior winter peak loads in the analysis, rather than summer peak load data modified by uncertainty factors; and**
e. **SPP should develop a 90/10 seasonal forecast procedure, like those employed by other regions, including MISO and ERCOT. As part of that procedure, SPP should consider breaking the SPP footprint into northern and southern sub-regions, given the potential for exponential load increase due to the resistive heating used in southern states. (Winter 2023-2024)**

ERCOT, MISO, and SPP anticipated winter reserve margins of 50 percent, 49 percent, and 59 percent, respectively, in the NERC seasonal assessment,[329] but all needed to shed firm load in February 2021. The combination of winter seasonal load forecasts that were substantially lower than actual peak load, and failure to consider the extent to which generation might be unavailable during winter peak weather in the anticipated winter reserve margins,[330] led to publicly-reported[331] reserve margin projections for the 2020/2021 winter season that could have led policy makers to make incorrect assumptions about the actual level of reserves that would be available during winter peak conditions. While planning reserve margins are designed to assess the overall capacity supply of the system, and not necessarily to predict energy requirements and operational scenarios, even the extreme-case assessments did not consider the extent to which the BAs' reserves were actually depleted during the Event. The extreme, or "90/10," scenarios conducted as part of the seasonal assessments should be designed to test a variety of extreme expected system conditions, such as

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[328] *See* note 28 regarding the role of solar units in the Event. If an entity is relying on a substantial amount of solar generation, this Recommendation could apply to solar generation as well.
[329] *See* NERC 2020-2021 Winter Reliability Assessment (November 2020), Data Concepts and Assumptions page 31, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf.
[330] The NERC 2020-2021 Winter Reliability Assessment did contain "seasonal risk scenarios" which included generator forced outages and higher loads; however, not at the magnitude experienced in the Event. These generator forced outages and higher loads are not included in the anticipated reserve margin projections.
[331] Entities such as ERCOT, MISO and SPP also perform winter seasonal assessments for their own internal use prior to each winter season. These assessments typically include a range of scenarios, with some that take into account lower generation availability and extreme peak load conditions in calculating less-optimistic winter reserve margins.

those that may be experienced during severe and prolonged cold weather. SPP should develop a statistically-based 90/10 load forecast.

During winter peak conditions, fuel for natural gas-fired generating units may be in competition with natural gas for residential heating needs. While the local distribution companies that supply natural gas for residential heating normally have firm commodity and transportation contracts, natural gas-fired generating units often have non-firm or interruptible contracts. When natural gas commodity or transportation availability is limited, natural gas-fired generating units without firm commodity and transportation contracts often cannot perform (or perform to their full expected capacity). This Key Recommendation encourages Planning Coordinators to recognize that they may not be able to count on the generating units' full capacity during winter peak conditions.

The variability in expected intermittent generating unit winter peak capacity may be affected by more than wind and irradiance. Factors that should be taken into account include the effects of cold weather precipitation conditions (ice and snow build-up).

For MISO, winter season Load Forecast Uncertainty percentages (LFU) should be based on the actual highest winter peak load day for each of the past 30 years. Zones 8, 9 and 10 (MISO South zones) could have significantly higher LFUs during winter peaks due to the volatility of winter load spikes due to electric heat.

VI. Additional Recommendations

Recommendation 10: Transmission Owners/Transmission Operators, in coordination with Distribution Providers and Reliability Coordinators, should evaluate load shedding plans for opportunities to improve their capacity for rotating manual load shedding, especially when load shedding is required for extended periods during stressed system conditions. These evaluations should consider:

a. **under what circumstances underfrequency load shedding circuits may be used for rotating load during longer duration events;**
b. **use of remote-controlled distribution circuit load interrupting devices (e.g., distribution line load break devices) to enable operators to deenergize and reenergize smaller portions of large distribution circuits to improve rotational load shedding; and**
c. **whether advanced metering infrastructure could be leveraged to achieve greater real-time distribution situational awareness (instead of being limited to distribution substation circuit-level) to more strategically deploy or better rotate manual load shedding, such as to shed non-critical large loads (e.g., a factory that is not operating during the cold weather event). (Winter 2023-2024)**

When the ERCOT BA system operators give an order to manually shed 1,000 MW firm load, that 1,000 MW is then automatically divided into pro rata shares among the ERCOT TOPs, with Oncor and CenterPoint having the largest shares at 36 and 25 percent, respectively. The TOPs' load-shedding provisions must be capable of taking the necessary actions to shed their pro rata shares of load in a timeframe adequate for mitigating the emergency.[332] The actual amount of load shed by each TOP, and for the entire ERCOT footprint, is usually larger than the amount ordered, because TOP system operators ensure that, at a minimum, their pro rata share of load shed is sufficient to address the emergency condition. Ideally, the TOP can shed the load automatically via SCADA—which permits operators in a control room to implement the load shed immediately. But in some cases, a TOP may have to dispatch field personnel to disconnect a circuit to accomplish a portion of the load shed, which is very time-consuming. The unprecedented amount of load shed that ERCOT BA operators needed to order at the peak of the Event to prevent system failure (20,000 MW), the duration of the maximum load shed, and the number of circuits that were off-limits, (whether due to critical load like hospitals and first responders, or UFLS/UVLS) meant that some TOPs could not rotate their outages. Instead the same customers remained out of service for many hours or even days. For example, during the Event, Austin Energy's general manager said, "[t]here

[332] The NERC Standards do not specify a required timeframe. ERCOT specifies that measures including manual load shed must be implemented to restore reserves (recovery of Physical Responsive Capability to 1,000 MW) within 30 minutes. *ERCOT Nodal Operating Guides (Feb. 1, 2021) Section 4: Emergency Operations.*

is no more energy we can shut off at this time so we can bring those customers back on," as all available circuits were serving critical load such as hospitals and water treatment centers.[333]

During the Event, the amount of load connected to UFLS circuits substantially exceeded the ERCOT-required levels at times for certain TOPs, due to high system loading and the reduction in demand from manual load shedding that had already occurred. One TOP noted that the load on its UFLS circuits exceeded 60 percent of its load at times during the Event, primarily due to manual load shedding. This is substantially higher than ERCOT's UFLS requirements and prevented the TOP from rotating much of its load. If a TOP has sufficient monitoring capability during an extreme load shed scenario to calculate the difference between the UFLS margin required versus the actual load on its UFLS circuits, the TOP may be able to use this "margin" from circuits normally reserved for UFLS to shed load and rotate outages, while still meeting its UFLS obligations. Such an approach could increase the amount of load available for rotating outages, spreading the burden of those outages to a larger and more diverse pool of load, and provide flexibility. It could also reduce the risk of an overshoot in frequency if UFLS were to operate while actual UFLS-connected loads substantially exceeded the required obligation.

The affected BAs' load shed plans in effect before the Event contemplated much smaller and shorter manual load shedding events than the Event. The plans did not consider an extended load shed scenario the size and duration of ERCOT's during the Event, or generating unit outages of the magnitude faced by ERCOT during the Event.

To increase the capabilities of their load shedding plans, TOPS and DPs should perform studies to identify circuits available for rolling blackouts that could decrease the duration and frequency of rolling blackout outages (e.g., review all critical load distribution circuits and identify non-critical load branch circuits connected) and identify additional methods of performing operator-controlled manual load shedding of the non-critical circuits while protecting the critical loads from de-energization.

TOPs and DPs should investigate using technology to enhance their ability to rotate load shedding, including use of remote-controlled distribution branch circuit load interrupting devices (e.g., SCADA-controlled distribution line load break devices) that can allow system operators to deenergize and reenergize the branch into smaller non-critical load segments of large distribution circuits. For locations where electric customer advanced metering infrastructure (i.e. "smart meters") has been deployed, this technology may be leveraged to provide real-time customer load information, which in turn can provide real-time monitoring of branch circuit loads to enable system operators to make more strategic decisions when implementing manual, rotational load shed.[334]

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[333] Katherine Blunt, Charles Passy, *In Texas, Winter Storm Forces Rolling Power Outages as Millions are Without Power*, Wall Street Journal (February 16, 2021), https://www.wsj.com/articles/winter-storm-forces-rolling-power-outages-in-texas-11613407767

[334] *See* U.S. Department of Energy - Office of Scientific and Technical Information, "Leveraging AMI Data for Distribution System Model Calibration and Situational Awareness" (2015), at https://www.osti.gov/servlets/purl/1237701 ("real-time monitoring, network restoration, outage management. . . energy loss optimization, and . . . and load control" are among the benefits of distribution system state estimation enabled by advanced metering infrastructure or "smart meters").

System operators need tools and EMS[335]/SCADA displays that track load shed outage locations, quantities, and their durations. Automated load shedding applications that rotate load circuits on a timed basis using the EMS/SCADA system and protect critical load can relieve operators of some of the burden during extended load shedding events, as compared to using manual tools and manual recordkeeping methods.[336]

For those circuits identified as requiring extended outages, TOPs and DPs should perform further simulation studies to identify any issues with reenergizing circuits due to high cold load pickup inrush currents.[337] TOPs and DPs should periodically review and update circuit data and disseminate maps showing the areas outaged by each circuit, and the areas protected due to critical load or UFLS/UVLS, to management and operators. DPs also should consider sharing some information about protected circuits with residential and commercial customers, so that they could understand why they see lights on nearby when their home or business has been without power for many hours.

And finally, TOPs need to regularly perform manual load shed training and drills to exercise use of their expanded manual load shedding plans, and ensure that the training covers their computer-automated load shed monitoring and control tools and applications.

<u>Recommendation 11</u>: Generator Owners should analyze mechanical and electrical systems not directly susceptible to freezing but which suffered failure during cold weather events, to assess the impact of extreme cold weather on mechanical stress, thermal cycling fatigue and thermal stress on plant equipment, as well as other effects of cold weather such as embrittlement of mechanical and electrical components. Generator Owners should use this analysis to take appropriate actions to prevent mechanical and electrical failure during cold weather events. Components and systems for analysis may include:

- **components dependent on lubrication for proper operation,**
- **fuel, air, and hydraulic filters,**
- **piping and wiring,**
- **superheaters and reheaters,**
- **boiler components, and**
- **insulation. (Winter 2023-2024)**

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[335] Energy management system.
[336] Not everything is better with a human touch. You need automation. - Survalent | Advanced Distribution Management Systems (ADMS) | SCADA, OMS & DMS (fully automated rolling load shed program that protects critical load).
[337] Cold load pickup is the phenomenon that takes place when a distribution circuit is reenergized following an extended outage of that circuit. Cold load pickup is a composite of two conditions: inrush and loss of load diversity. Cold load pickup includes a combination of non-diverse cyclic load, continuously operating load, transformer magnetizing current, capacitor inrush current and motor starting current. The combination can result in load levels that are significantly higher than the circuit's normal peak load levels.

The majority of generating units in ERCOT and MISO South are exposed to the elements, compared to many in SPP and those in MISO North, where generating units are typically enclosed. The open configuration of generating units in ERCOT and MISO South makes them more susceptible to cold-weather-related failures. Although most GOs/GOPs attested to ERCOT that they completed winter readiness actions prior to the Event, failures of systems directly or indirectly tied to cold weather occurred. Non-freezing-related mechanical/electrical failures of systems and components reported by GOs/GOPs included:

- Oil lube systems including lube oil pumps. Pump bearing or seal-wear-related failure is not uncommon. Pump motors and gears may also fail. If the lubricant is not rated for low temperatures, failures that look like inadequate lubrication or sticky lubricant may occur. (e.g., lube oil pressure switch in boiler feed pump failed to turn on the lube oil pump).
- Elastomeric seal materials are subject to low temperature embrittlement failure.[338]
- Wiring issues (e.g., solenoid failure). Accumulated damage from heating (current flow), voltage stress, vibration, or corrosion will eventually cause coil failure which is usually marked up to "aging." Sometimes changing plant output adds the final stress needed for a solenoid failure, so these issues are often discovered while starting up a unit, ramping, or in a sudden load change. Many solenoids require lubrication – cold gelling of lubricant can make solenoids stick (e.g., when attempting to restart a unit, a stuck solenoid prevented restart, or a purge vent valve solenoid failed to modulate during the startup sequence and prevented the unit from synchronizing).
- Condensate and feedwater heating system issues. These generally have steam traps and small-diameter drains that, if unprotected from freezing, can cause problems with water flows and levels, so some of these outages could be cold-weather-related (e.g., a unit was available to start but was kept offline due to limited condensate water from the steam host).[339]
- Boiler issues (e.g., water wall tube leaks). Although some amount of boiler issues is to be expected in a facility with steam boilers, and some failure tolerance is normally built into the unit design, too much tube leakage will require a unit shutdown. Among the factors that will tend to increase failures of steam equipment are thermal stresses related to rapid startups, load changes, water chemistry problems, and uneven heating (firebox/fuel side issues).
- Vent and control valves are subject to internal and external failure mechanisms. Internally, mechanical wear, erosion, fatigue, chemistry, and maintenance issues tend to dominate as failure causes. These internal failures are usually revealed by leakage or changes in flow characteristics over time. External failures can be initiated by actuator or control failures – these may be influenced by cold issues such as freezing of a sensing line, differential thermal expansion of supports and restraints, or hydraulic control system failures which may lead to

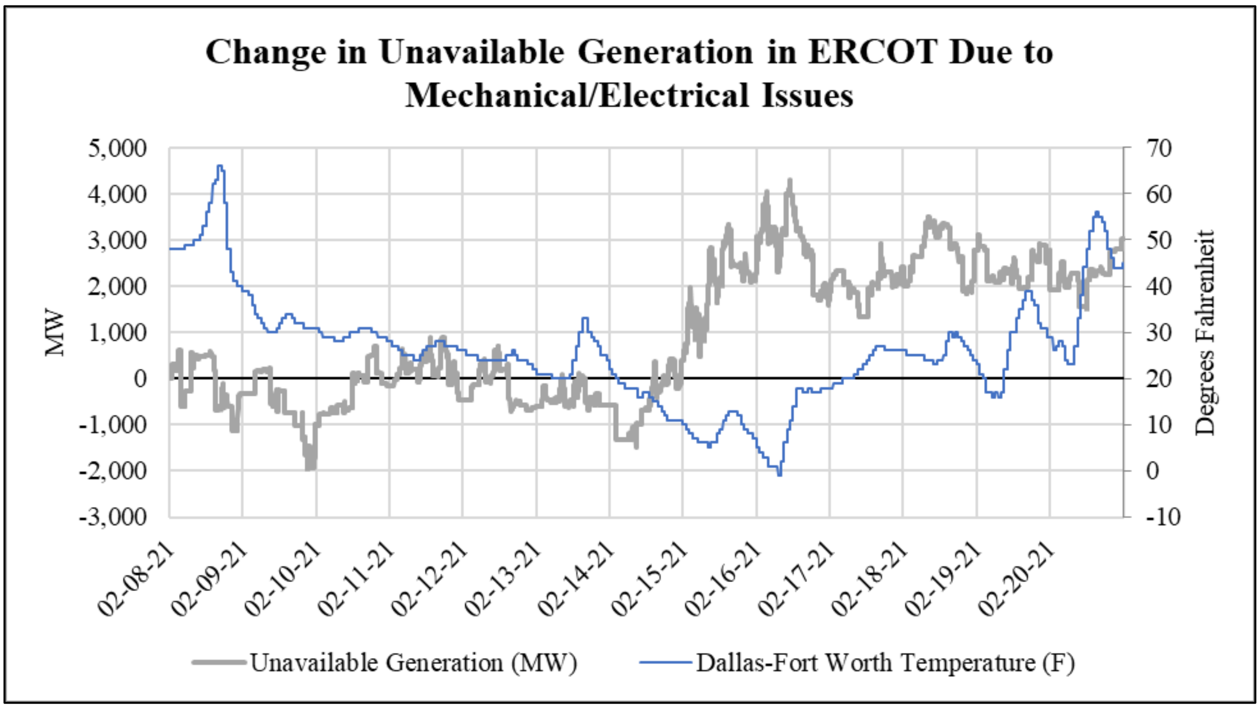
[338] Elastomeric means flexible or stretchy, such as plastic, rubber, or silicone materials. Thin metal bellows may also succumb to low temperature embrittlement. All flexible seal materials have operating temperature range limits.
[339] Some of these items may also use elastomer seals and boots that have minimum temperature limits to avoid embrittlement, but they were not identified in outage data.

limited or improper movement (e.g., a control valve or manual bypass valve leak resulted in high fuel gas pressure trip of two engines).

- Tuning for combustion turbine generating units is fuel- and temperature-sensitive. Derates have been reported due to intake low air temperature (e.g., an engine running at a much lower inlet temperature than it was tuned for caused unit to be derated, due to unstable combustion and acoustic vibrations that could damage turbine components).

Unplanned incremental generating unit outages, derates and failures to start attributed to mechanical/electrical issues during the Event caused a total of 103,096 MW of non-coincident outaged generation during the Event.[340] Although they were not directly caused by freezing, these outages are associated with the cold weather—as temperatures fell, the incidence of mechanical/electrical issues increased. See Figure 105, below.

Figure 105: Change in Unavailable Generation in ERCOT Due to Mechanical/Electrical Issues



In the 2018 event, a similar pattern was evident—the total generating unit outages were correlated with temperatures—again, as temperatures fell, the incidence of unplanned outages and derates increased.[341]

[340] *See* discussion in Analysis, sections IV.A and B, and Figure 93.
[341] 2018 Report at 80 (three cities had correlation coefficients of -0.7 or greater, and the majority of cities had coefficients of -0.5 to -0.7).

Some of these mechanical/electrical failures may be indirectly related to freezing issues, such as stress caused by freeze-thaw cycles. Unlike direct freezing issues, these failures are not necessarily prevented by heat tracing and insulation. At temperatures outside of the design operating temperatures, differential thermal expansion may cause mechanical overload of restraints, supports, structures or add to other existing loads (look for bowing, cracked welds, failed bolts, tighter- or looser-than-expected fittings or joints).

GOs should consider the following (and related or similar) systems, components and potential mechanisms leading to failure:

- Components dependent on lubrication for proper operation (e.g., lubricated gearbox), or which seem to have failed due to being improperly lubricated, may be due to operation at colder temperatures for which the lubricant was rated. Lower temperatures increase lubricant viscosity, which restricts lubricant flow and can alter its efficiency.
- Fuel, air, and hydraulic filters can be affected by cold air. Moisture in the air or collected by the fuel filter, or contaminating hydraulic fluid, may freeze and block filters.
- Temperatures below the material's rating can cause pipes and plastic wiring insulation to become brittle. Material near welds may have different properties from the general metal piping or structure that could cause the welds to weaken.
- Superheaters and reheaters can experience additional thermal stress and fatigue[342] from temperature changes.
- Extreme temperature changes can also impact other types of aging equipment. For instance, aging insulation can become brittle during cold weather, making failure more likely.
- Low temperature fatigue cracking (e.g., economizer inlet tubes, furnace wall tubes, steam drum internals) can occur when relatively cold water enters hot boiler components.

While the magnitude of these generating unit outages cannot be ignored, without more evidence as to the actual causes of the association between unplanned mechanical/electrical outages and cold temperatures, it will be difficult to craft the appropriate remedies, whether it be a potential Reliability Standards revision or some other action. The Team recommends further analysis by GOs to understand the impact of extreme cold weather on mechanical/electrical failures, so that GOs can identify possible methods of reducing the incidence of unplanned outages, derates and failures to start due to mechanical/electrical issues during similar events.

<u>**Recommendation 12**</u>**: Generator Owners and Generator Operators should incorporate weather forecasts into planning the operation of their generating units prior to cold weather to lessen the impact of cold weather events on the performance and availability of the units. For example, adding a temporary wind break can protect exposed equipment that could potentially freeze (based on the forecasted wind and/or precipitation). (Winter 2021-2022)**

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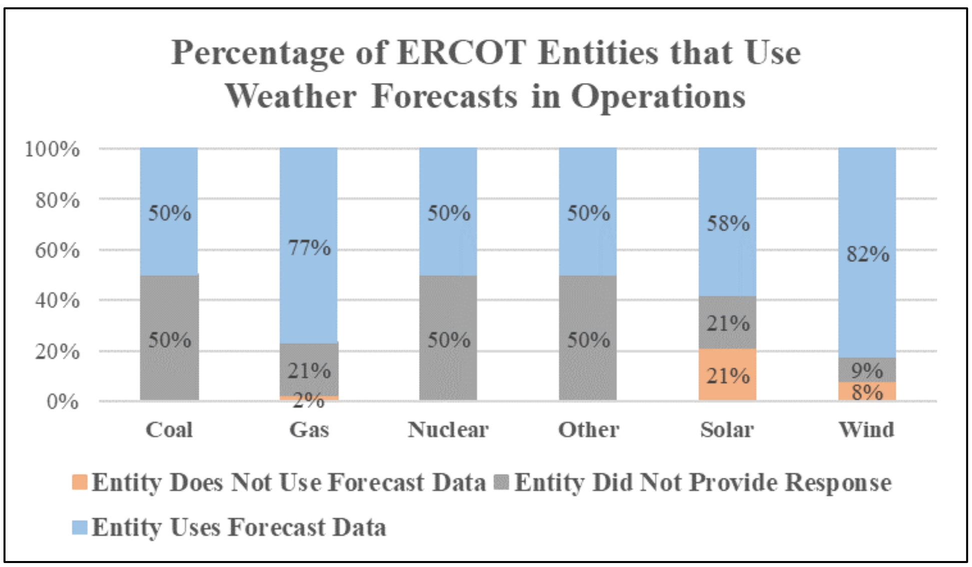
[342] Fatigue is defined as a process of progressive localized plastic deformation occurring in a material subjected to cyclic stresses and strains at high stress concentration locations that may culminate in cracks or complete fracture after a sufficient number of fluctuations.

Having accurate weather forecasts allows GOs/GOPs to plan and better prepare for extreme cold weather events. Cold weather preparations that can occur shortly before a forecasted cold weather event include checking insulation for gaps, checking heat tracing to make sure all circuits are fully operational, adding wind breaks and heaters to protect critical components and systems, adding temporary shelters to protect critical components and systems from freezing precipitation, and adding heaters to uninsulated rooms. When evaluating actions to take in response to the weather forecast, GOs/GOPs should be mindful of the accelerated heat loss due to wind, and its effect on a generating unit's operations.[343] Critical components and systems that are exposed may freeze more quickly due to the accelerated heat loss caused by wind.

Of the 132 GOs/GOPs surveyed in ERCOT, 114 (86 percent) provided information related to their weather forecasts and associated actions. As shown in Figure 106 below, the majority of wind and gas generators within ERCOT reported incorporating temperature forecasts in their planning or operations.[344]

Figure 106: ERCOT Generator Owners/Operators that Incorporated Weather Forecasts in Operations



Some GOs/GOPs surveyed did not use weather forecast data for operational planning. For example, some wind and solar GOs/GOPs explained that expected temperature is not a metric they considered in output forecasting (but could be relevant to preparing for a severe cold weather event). A few GOs/GOPs that did use weather forecast data during the Event reported actual temperatures substantially lower than forecasted temperatures. One GO/GOP reported that the low temperature on February 9 was 18 degrees lower than the next-day temperature forecasted and the low temperature on February 15 was 13 degrees lower than the next-day temperature forecasted.

343 *See* 2011 Report Appendix "Impact of Wind Chill."

344 Note: Entities that reported multiple fuel types are counted separately for each fuel type in the chart.

Another GO/GOP reported that the temperatures for Austin, Texas were up to 18 degrees lower than the hourly day-ahead forecasted temperatures from February 9 to 10 and eight degrees lower than the forecasted temperatures on the night of February 14 to 15.

The 14 GOs/GOPs surveyed in MISO South own a total of 71 generating units, and all surveyed entities used weather forecasts. However, only six percent (4 of 71) provided forecasts that accounted for the cooling effect of wind.

Thirty-two SPP GOs/GOPs provided data for 318 generating units, and nearly all surveyed entities used weather forecasts. However, only 27 percent (87 of 318) provided weather forecasts that accounted for the cooling effect of wind. Three percent of GOs/GOPs who did not use weather forecasts for planning and operations justified it by stating that their resources are designed to operate in cold weather temperatures.

Those GOs/GOPs that did use weather forecasting for planning and operations used a variety of available weather forecast sources, ranging from NOAA data and subscription forecast services. Some GO/GOPs used a combination of sources, while others had meteorologist on staff to support their weather forecast needs. Additional forecast sources include TV and radio news, ERCOT Senior Meteorologist daily report, Weather Services International, Meteologica, Weather Underground, Global Forecast System, StormGeo.com, and weather.gov, among others.

Recommendation 13: Generator Owners within the ERCOT Interconnection should review the coordination of protective relay settings associated with generator underfrequency relays, balance of plant relays, and tuning parameters associated with control systems, which could trip generating units during low frequency or high rate-of-change of frequency conditions. Also, to evaluate how often generating units trip due to these causes, NERC should consider adding a Generating Availability Data Source Cause Code Amplification Code[345] for outages related to frequency deviation. (Winter 2022-2023)

The condition that most threatened BES reliability during the Event was ERCOT's low frequency excursion on February 15, which was caused by unplanned generation outages and derates in the ERCOT footprint. Due to the loss of Physical Responsive Capability of the generators that were online, the frequency began to steadily decline. As the frequency declined, several generators tripped offline due to the lower frequency level or rapid rate of frequency change: approximately 1,769 MW of coal generation and 2,190 MW of gas generation experienced unplanned outages from this cause. For instance, a 933 MW coal unit tripped due to the rapidly-changing frequency, which affected the boiler controls, caused a high boiler pressure condition, and tripped the unit. Another unit reported that the low frequency condition caused the turbine speed and air flow to decrease, which led to a temperature increase that tripped the unit. Additional examples are shown below in Table 107b. ERCOT should implement an expedited review of all BES generators within its footprint to identify the extent of this condition, and identify steps for mitigation. The results from

[345] According to NERC, "the purpose of the amplification code is to further identify the cause of an outage by describing the failure mode. The amplification code is two alpha-numeric characters following the cause code . . . Failure modes are leaks, corrosion, personnel error, fire, etc." Appendix J: Cause Code Amplification Codes (nerc.com)

implementing this Recommendation should considered as part of the study recommended by Recommendation 27, regarding low frequency or high rate-of-change of frequency conditions in the other interconnections.

Events related to grid frequency disturbances are not typically separately-captured when entities report their generator outages to NERC. This is partially due to the lack of a cause code amplification code for grid frequency events occurring on the BES in the GADS[346] cause codes. The lack of a GADS cause code amplification code means that generating unit outages caused by frequency disturbances are instead attributed to another cause, preventing accurate assessment of the magnitude of the problem. Unlike GADS, the Team did not rely on cause codes but collected multiple descriptions of the reasons for the outages from the GOs/GOPs, which allowed it to collect the data summarized in Figure 107a and 107b, below:

Figure 107a: ERCOT Generating Units (by Fuel Type) that Experienced Outages due to Low Frequency or High Rate-of-Change of Frequency Conditions During February 15 Frequency Decline/Recovery Condition

Fuel Type	Number of Outages Reported	Grid Disturbance (Frequency) (MW)
Gas	11	2,190
Coal	2	1,769
Total	13	3,959

346 NERC's Generating Availability Data System (GADS) is a mandatory industry program for conventional generating units that are 20 MW and larger. Generating Availability Data System (GADS) (nerc.com))The reporting requirements are specified in the GADS Data Reporting Instructions (DRI). GADS maintains operating histories on more than 5,000 generating units in North America. Through GADS, NERC collects information about the performance of electric generating equipment and provides assistance to those researching information on power plant outages. GADS data also supports equipment availability analyses, is used to conduct assessments of generation resources, and to improve generator performance. GOPs enter GADS cause codes when reporting generating unit outages or derates and data can then be compiled by that cause code. For example, there is a specific cause code (5009) for "other inlet air problems."

Figure 107b: Causes of ERCOT Generating Units (by Fuel Type) that Experienced Outages due to Low Frequency or High Rate-of-Change of Frequency Conditions During February 15 Frequency Decline/Recovery Condition

Fuel Type	MW	Cause
Coal	933	At 01:55 grid frequency began to quickly increase from a low of 59.3 Hz. Boiler demand began to decrease, turbine valves began to close, and boiler pressure began to rise. The energy from the boiler could not be removed fast enough and boiler pressure increased to a point where the unit is tripped on high boiler pressure.
Combined Cycle	594	Frequency drop caused mass air flow reduction, which caused high pressure superheat tubes' temperature to increase, tripping the unit.
Gas	213	Combustion turbine tripped by automatic voltage regulator on excessive MWs during frequency disturbance.
Gas	105	Gas turbine inlet guide vanes stuck during a low frequency event.
Coal	836	Frequency disturbance caused low boiler circulating water inlet pressure, tripping unit.
Combined Cycle	572	2x1 combined cycle unit tripped due to loss of auxiliary bus during grid frequency disturbance

Recommendation 14: Owners and operators of natural gas production facilities should consider upgrading SCADA controls to improve real-time local monitoring of wellhead sites, which could allow them to incrementally increase or decrease production in response to real-time events. (Winter 2023-2024)

Natural gas production facilities that used updated technology to monitor and control their facilities during the Event were able to manage and assess operational data and develop plans for managing production issues in a more efficient and timely manner. Discussions with production entities revealed that nearly all producers have some basic level of remote monitoring capability, and most producers have some SCADA control capability (e.g., remote shutoff), with some implementing more advanced systems capable of managing flow (both through local and remote flow automation technology) and remote startup. SCADA systems are used in both electric and natural gas infrastructure to communicate between facilities. Advanced SCADA systems[347] exist that can enhance situational awareness by providing infrastructure operators with access to production facilities' real-time, accurate data, and allowing operators to remotely monitor, control and optimize their processes. Among other things, advanced SCADA can:

- maintain and adjust production operations in coordination with downstream processes and systems, including the ability to remotely shut-in and restart production wells;
- provide operational data from the field needed to perform equipment maintenance;
- provide data to ensure personnel, environmental and equipment safety; and
- provide information for third-party logistics necessary to maintain product flow (e.g., water hauling can be scheduled and implemented based on the actual, real-time data –such as when tanks are approaching levels requiring fluid removal from the site –as opposed to pre-determined, static schedules).

With more advanced SCADA capabilities, production facility operators gain more efficient control, including more efficient management of operational issues, as well as more orderly and expedited return of production facilities to operation as system conditions improve. One entity that has implemented an advanced SCADA system across its production operations was able to (1) monitor water levels, which enabled it to prioritize low-water-producing wells and shut in higher-water-producing wells; (2) restart wells remotely during the Event, if a well shut down due to certain non-freeze-related causes; (3) control volume/flow from the wells to maintain proper line pressure for the downstream facilities to mitigate production equipment freeze-offs; and (4) more effectively return production to normal by using remote startup.

As entities implement advanced SCADA technologies, they need to develop mitigation plans to respond to weather-related issues that could impair access to SCADA systems, including such considerations as ensuring availability of power for the instrumentation and controls/electronics equipment (e.g., securing additional/spare batteries) and ramping up the capacity of maintenance, field operations and control room personnel to respond in advance of emergency situations.

<u>Recommendation 15</u>: State, federal and local authorities should consider developing and/or enhancing existing emergency centers, using gas and electric coordination/information sharing (see Key Recommendation 7), in preparation for and during extreme weather events, similar to the Department of Homeland Security's Fusion Centers.[348] These centers

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[347] The Team does not advocate for any particular products but notes that cloud-based, scalable SCADA systems exist that promise to allow the collection of remote data in real time and allow operators to run less-efficient wells only a few times a year, among other functions
https://www.automationworld.com/products/control/news/13319708/cloudbased-scada-drills-in-on-oil-wells

[348] https://www.dhs.gov/fusion-centers/. Also, the Department of Energy's Office of Cybersecurity, Energy Security and Emergency Response, the mission of which is to "respond to and facilitate recovery from energy disruptions in collaboration with other Federal agencies, the private sector, and State, local, tribal, and territory governments," would likely participate in this effort. *See* https://www.energy.gov/ceser/office-cybersecurity-energy-security-and-emergency-response ; State, Local, Tribal, and Territorial (SLTT) Program | Department of Energy.

could facilitate federal, state and local coordination to enhance the reliability of the Bulk Electric System and natural gas infrastructure in areas including, but not limited to:

- **communication and coordination with, and mutual assistance to, natural gas and electric infrastructure entities;**
- **waiving state or federal laws such as the Clean Air Act (to help backup/dual-fuel units run for longer times) or Jones Act (to allow transportation of U.S.-sourced liquefied natural gas between U.S. ports and enable domestic use);**
- **issuance of Motor Carrier Safety Administration – Regional Emergency Declarations,**
- **Department of Energy Federal Power Act Section 202(c) use for Emergency Waivers ("Secretary of Energy may require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary determines will best meet the emergency and serve the public interest");**[349]
- **highway/road access to natural gas infrastructure (e.g., for removing water or other liquids from wellheads or mitigating damage from freezing); and**
- **Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and natural gas infrastructure entities jointly developing, facilitating, and participating in regional-based natural gas-electric extreme weather scenario operations training drills (factoring in the above-listed areas) in preparation for extreme weather events and using the results of those drills to improve emergency operations. For example, the results of the drills could help to establish clear roles and responsibilities, identify and prioritize tasks, improve emergency communication, and improve implementation of emergency operations plans. (Winter 2022-2023)**

This Recommendation builds on Key Recommendation 7, which seeks to establish a forum to build greater cooperation and communication between natural gas infrastructure and BES entities. The reliability of the BES is of critical importance to all sectors of society—commercial, industrial, retail, public safety, communications, etc. This Recommendation recognizes that maintaining the reliability of the BES during extreme cold weather and freezing precipitation like that experienced during the Event can require action by Federal, state, and local entities. DOE activated its emergency response team at the onset of the Event and coordinated with industry, interagency, and state entities to provide situational awareness and support restoration efforts.[350]

Recognizing that emergency response resources are finite, setting priorities is critical. For example, a state or county may want to forego clearing roads in certain areas to prioritize sending crews to clear and treat roads that allow access to natural gas and electric infrastructure facilities. Truly effective emergency response is more than just bringing the right people together. An overall regional

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[349] *See* DOE's Use of Federal Power Act Emergency Authority | Department of Energy, *see also* Federal Power Act Section 202(c) – ERCOT, February 2021 | Department of Energy – list (and links) of emergency order issued to ERCOT in February 2021 along with subsequent compliance filings and lists of generators.
[350] *See* DOE Office of Cybersecurity, Energy Security, and Emergency Response, at https://www.energy.gov/ceser/february-2021-extreme-weather-incident.

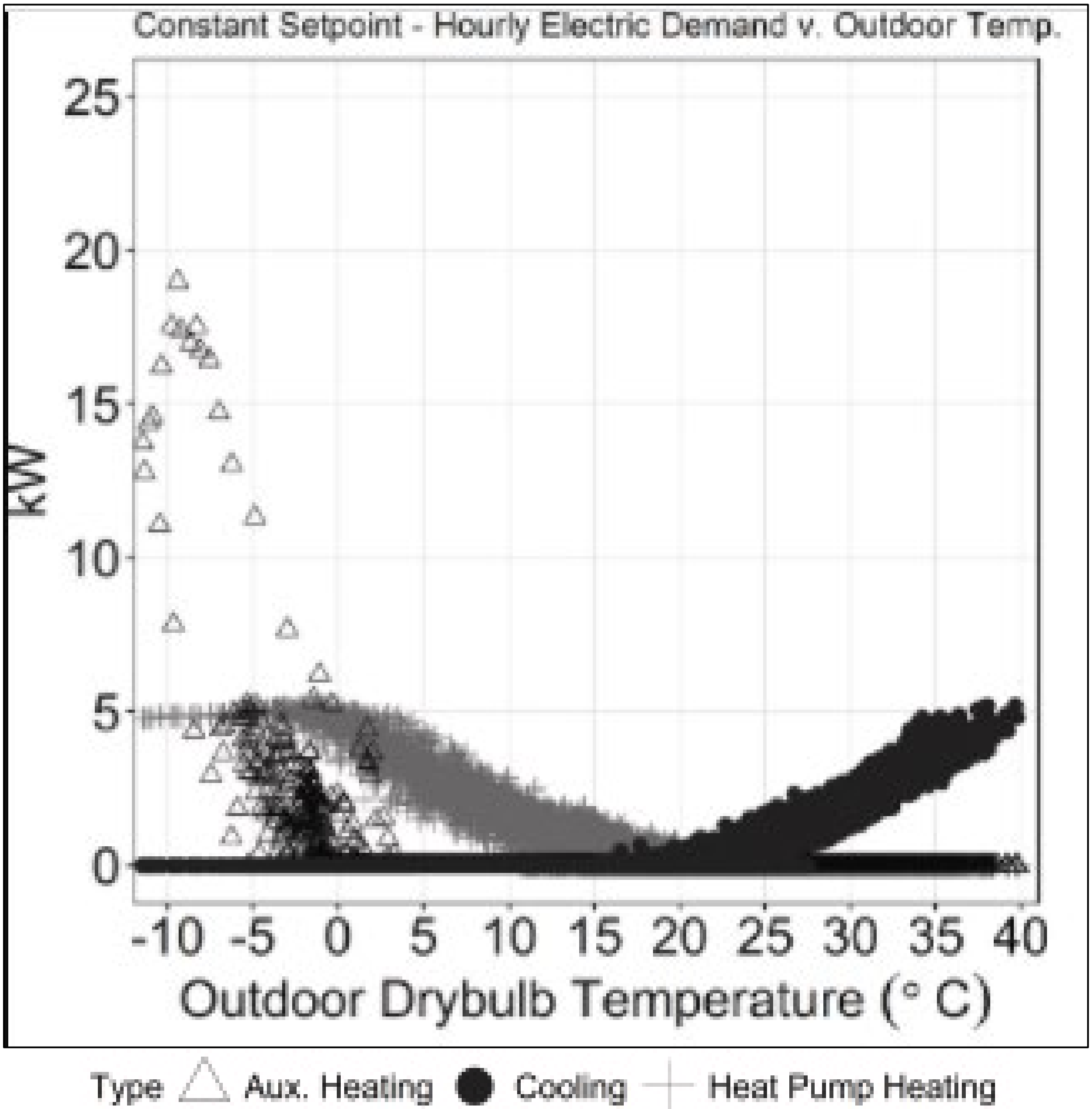
emergency coordinator, tasked with quickly developing a response strategy across federal, state, and local agencies and response teams for the emergency condition, would greatly enhance the chances of success during a future event. An important first step would be identifying responsibility for establishing the control center, which would have the ability to share real-time information across sectors. A successful strategy would identify priorities for restoring electric and natural gas infrastructure. The existing emergency center constructs could be enhanced to include the areas that are listed above in the Recommendation. Once the agencies and entities have established their coordination relationships, the Team recommends that the appropriate entities, including RCs, BAs, TOPs, GOPs, and natural gas infrastructure entities, perform regional-based natural gas-electric extreme scenario operations training drills to assist in identifying priorities and restoration steps and practicing their execution.

Recommendation 16: Balancing Authorities should have staff with specialized knowledge of how weather impacts load, including the effects of heat pump backup heating and other supplemental electric heating. Balancing Authorities should also broaden the scope of their near-term (seven-days prior to real-time) load forecast to include multiple models and sources of meteorological information to increase accuracy and should consider regional differences within their footprints. (Winter 2022-2023)

Electric heat pumps provide a significant portion of the residential heating load in the southern U.S. Heat pumps have a rated outdoor operating temperature, which is the minimum temperature at which the unit will efficiently operate. As temperatures drop, the heat pump is able to extract less heat from the ambient air, requiring more electricity to generate the quantity of heat (BTUs) it would at warmer temperatures. During severe cold weather, heat pumps become ineffective and those homes must rely on auxiliary (aux.) electric resistance heating instead. Figure 108, below illustrates standard behavior for air electric heat pump and auxiliary heat for an example older residential home.[351] As seen in the figure, as temperatures decline below zero degrees Celsius (32 degrees Fahrenheit), "Aux. Heating" is triggered to provide home heating needs. The hourly electric demand in kilowatts increases sharply as temperatures decline. Below -10 degrees Celsius (14 degrees Fahrenheit), the home heating demand due to auxiliary heating as seen in Figure 108 ranges from two to nearly four times the demand that it was at 32 degrees Fahrenheit.

[351] Philip White et al., *Quantifying the impact of residential space heating electrification on the Texas electric grid,* 298 Applied Energy 1, 1-11 (2021); https://www.sciencedirect.com/science/article/pii/S0306261921005559?via%3Dihub

Figure 108: Air-Source Residential Heat Pump Hourly Electric Demand Versus Outdoor Temperature, with Auxiliary Heating Demand



BA staff, especially those in southern areas with substantial electric heat pump load, need to understand how changes in weather can be reflected in the above-illustrated auxiliary heating demand characteristics as supplemental heating sources are used during cold weather.

Selecting multiple weather sources for information is critical to the accuracy of load forecasting, given the sensitivity to substantial increases in heating load for every degree drop in temperature, as seen in Figure 108, above. Accurate near-term load forecasts allow for the proper scheduling of fuel supplies, commitment of generation, scheduling of interchange and scheduling of maintenance activities. BAs should use multiple sources of meteorological data and ensure that the data they receive reflects the regional differences within their footprints (e.g., MISO South, southern SPP). BAs should input this data into multiple models to provide the most accurate near-term load forecasting and cross-check the results.

Recommendation 17: In performing their near-term load forecasts, Balancing Authorities should analyze how intermittent generation affects their ability to meet the peak load (including the effects of behind-the-meter intermittent generation) (for the entire footprint as well as sub-regions, such as MISO South and SPP's southern region), especially if peak load cannot be met without variable resources. Balancing Authorities should consider performing a 50/50 or 90/10 forecast for renewable resources three-to-five days before real time. (Winter 2022-2023)

The near-term weather forecast inputs for all three BAs in the Event Area differed from actual weather forecasts, especially for longer-lead times (i.e., three-to-five days ahead of the operating day). Their common short-term weather forecast inputs (dry or wet bulb temperature), dew point and humidity, wind speed and chill, cloud cover, solar irradiance or sunshine minutes, and precipitation) were found to possess larger uncertainty for the longer lead-time forecasts. By introducing probabilistic methods for these weather inputs, entities will better be able to take into account weather forecast risk. BAs should analyze a range of forecast scenarios for each of the winter weather inputs for forecasting both the total load and net load (effects of behind the meter intermittent generation) forecasts, as well as for their intermittent resource forecasts. Examples of winter weather forecast uncertainty scenarios for analysis three to five days ahead may include:

- for total load forecasts:
  - High wind, lower-than-forecast temperature scenario, and
  - Low wind, higher-than-forecast temperature scenario;
- For net load and resource intermittent generation/resource capability uncertainties:
  - High wind, high solar, higher-than-forecast temperature scenario, and
  - Low wind, low solar, lower-than-forecast temperature scenario.

Probability distributions for each of the weather inputs can be selected based on historical winter weather conditions, including extreme winter weather conditions (e.g., develop 50/50 and 90/10 uncertainty forecasts). Using a probabilistic approach to the three-to-five day before real time winter weather forecasts for load and intermittent resources will enable BAs to quantify risk and develop operating plans that better plan for uncertainty.

Recommendation 18: Independent System Operators/Regional Transmission Organizations and/or state public utility commissions should consider providing incentives for additional demand-side management resources that could be deployed in a short period of time (i.e., 30 minutes or less), especially to replace unplanned outages or derates of generating units, and where resources are most likely to be needed during times of short supply (e.g., the southern portions of MISO and SPP footprints, other southern areas that could lose generating units during extreme cold). They should also consider how to better educate retail customers on steps they can take to help alleviate the need for load shed during extreme weather events, and how to effectively alert customers during emergencies. (Beyond winter 2023-2024 but as soon as possible)

Demand-side management or "demand response" is not a new approach to reducing load during events where electricity supply margins are narrow. The consequences of the extended and widespread firm load shed in ERCOT showed the limits of relying entirely on mandatory firm load shed in such an emergency. To prepare for the possibility of a similar event requiring large amounts of firm load shed, this Recommendation suggests that ISOs/RTOs and/or state public utility commissions pursue additional voluntary demand response programs/resources that would enable grid system operators to quickly respond during grid emergencies, as well as potentially lessen the amount of firm load shed and the durations of the outages. One possibility would be a program that could cycle outages only to certain home appliances, instead of taking out entire circuits, as happened during the Event. ISOs/RTOs would need to coordinate with electric service providers (TOPs and DPs) for program development and implementation. Public utility commissions play a role, not only in structuring incentives for demand response products, but also in educating retail electricity customers about the risks and rewards of participating in demand-side management programs, and how to minimize the need for firm load shed.

<u>Recommendation 19</u>: State public service/utility commissions or legislatures should consider retail-level incentives for energy efficiency improvements. Such incentives could include energy efficiency audits and subsidizing energy efficiency measures with public funds. (Beyond winter 2023-2024 but as soon as possible)

One way to reduce load during extreme cold weather is to increase the ability of the housing stock to withstand the ambient temperatures through energy efficiency measures such as increased insulation, weather-stripping, energy-efficient windows and doors, etc. Another report on the Event recommended increasing energy efficiency retrofits for low-income and multi-family housing across Texas.[352] A similar pre-existing program is EmPower Maryland, a legislatively-mandated program which began in 2008 and met its goal of reducing per capita electricity usage and peak demand by 15 percent by 2015. "Programs include lighting and appliance rebates, HVAC, Home Performance with Energy Star, Energy Star New Homes, combined heat and power, and other efficiency services and/or measures for homes, businesses and industrial facilities. Natural gas offerings are [also] available to eligible . . . customers." Finally, low-income customers in Maryland can participate in the Low Income Energy Efficiency Program, which "assists low-income households with installation of energy conservation measures in their homes with zero out-of-pocket expenses."[353] Each state can assess how efficiently its housing stock is using the energy it consumes during an emergency like the Event and can decide whether investments like those envisioned by the Wood report or implemented in Maryland to reduce its peak demand are a worthwhile use of incentives.

<u>Recommendation 20</u>: Adjacent Reliability Coordinators, Balancing Authorities and Transmission Operators should perform bi-directional seasonal transfer studies, and sensitivity analyses that vary dispatch of modeled generation to load power transfers to reveal constraints that may occur, to prepare for extreme weather events spanning multiple

[352] Recommendation 2-3 in the June 3, 2021 report by former FERC Chair Pat Wood III and several former PUCT members, https://www.cgmf.org/blog-entry/435/REPORT-%7C-Never-Again-How-to-prevent-another-major-Texas-electricity-failure.html
[353] https://www.psc.state.md.us/electricity/empower-maryland/

Reliability Coordinator/Balancing Authority areas like the Event. Such studies should include transmission limits on exports/imports from neighboring areas during stressed conditions, and unusual flow patterns similar to the patterns documented during the Event (east-to-west flows versus normal west-to-east, import flows into and through MISO of well over 10,000 MW) (or other unusual flows seen during extreme winter weather events for the entities performing the studies). The studies should also consider sub-areas or load pockets which may become constrained. The study results can be used to create operator training simulator (OTS) training scenarios. (Winter 2022-2023)

During the Event, RCs, BAs, and TOPs in the Eastern Interconnection reported observing greater-than-normal and abnormal export/import transfers between RC Areas and across their internal transmission systems. Throughout the Event, as each entity continued to maintain stability and reliable operations of its respective system, entities also provided as much assistance to their neighboring systems as possible without sacrificing system reliability. MISO reported a particular moment during the Event when it recorded approximately 13,000 MW of total power flowing into its footprint from adjacent BAs east of its footprint (east-to-west power flows) to aid in meeting winter peak load conditions and alleviating generation shortfalls. This pattern differed from what MISO typically experiences, which is west-to-east power flows due to exports from MISO to BAs east of their footprint (e.g., PJM[354]). The recommended transfer studies and analyses should model high transfers at high seasonal load conditions, to levels at which constraints cannot be fully alleviated without emergency measures (e.g., greater than 10,000 MW for MISO and SPP).[355] The results of these studies should be used for operations preparedness, including to develop new operating procedures for the abnormal flows and conditions modeled, as well as incorporated into system operator drills.[356]

<u>Recommendation 21</u>: **Reliability Coordinators, Transmission Operators[357] and Distribution Providers, should regularly, at least once annually, perform Operator Training Simulator simulations, if available, of firm load shed scenarios, to train system operators to administer rotating load shed, avoid cascading outages and system collapse, and protect critical natural gas infrastructure customers. Scenarios should include extreme scenarios similar to the Event, which require rotating load shed and system restoration. (Winter 2022-2023)**

Manual load shed is not a task which system operators perform daily, but it is critical to perform well when needed. As the Event demonstrated, system operators may be faced with situations beyond anything they ever expected. Frequent training in the basics as well as extreme scenarios like the

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354 While PJM was providing assistance to MISO and other adjacent BAs, it observed an all-time record net export transfer across connecting tie lines of approximately 15,700 MW.

355 This Recommendation is similar to Recommendation 8 from the 2018 Report (at page 95) and the Team recommends that BAs and RCs with seams/adjacent BAs and RCs review the two Recommendations together.

356 The models, studies and operations should incorporate established facility ratings and associated System Operating Limits based on ambient temperature conditions that would be expected during high seasonal load conditions. *Id.,* Recommendation 9, page 96.

357 In some areas, Transmission Owners are involved in manual load shedding, and should be included in this Recommendation.

Event will help operators be as prepared as possible for the unexpected. System operators need to practice shedding load, rotating the load shed, restoring load, and protecting critical natural gas infrastructure customers from being deenergized. Once the development of the firm load shed scenarios is complete, system operators should test these scenarios in a training environment through use of simulation tools, incorporating control room applications which assist operators in performing automatic rotation of load. Including scenarios similar to the Event in training and simulation tools would allow larger load shed scenarios to be better coordinated and minimize potential impacts in future events.

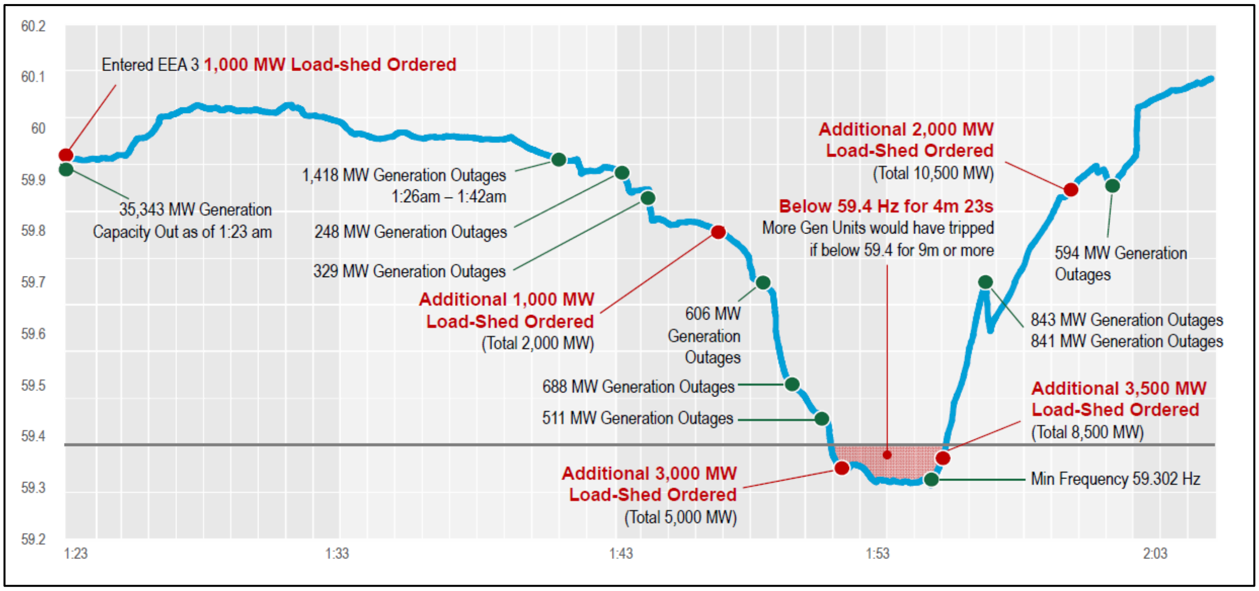
Recommendation 22: Planning Coordinators, Transmission Owners and Transmission Operators should coordinate with Generator Owners/Generator Operators to ensure that generating units are not tripped by time-delay protection systems before the first step of underfrequency load shedding is deployed. This coordination may require an underfrequency load shedding settings change to increase the first-step frequency, as well as notification to Balancing Authorities. The Regional Entity should review any changes proposed by the Planning Coordinator for (1) consistency with Standard PRC-006-5 - Automatic Underfrequency Load Shedding, and (2) whether a revision of, or regional variance from, Standard PRC-006-5 is warranted. (Winter 2023-2024)

ERCOT Nodal Protocols and NERC Reliability Standards[358] allow generators to automatically trip offline, or automatically shut down and disconnect from the grid, if the grid frequency drops to 59.4 Hz or below for more than 9 minutes. During the early morning hours on February 15, ERCOT's system frequency was less than 59.4 Hz for over four minutes, but remained above the first step of underfrequency load shedding (59.3 Hz).

If ERCOT's system frequency had remained below 59.4 Hz, but above 59.3 Hz for another four and a half minutes, a potentially large block of generation could have tripped by underfrequency relays. Consequently, the grid was within minutes of a much more serious and potentially complete blackout on the morning of February 15. See Figure 109, below.

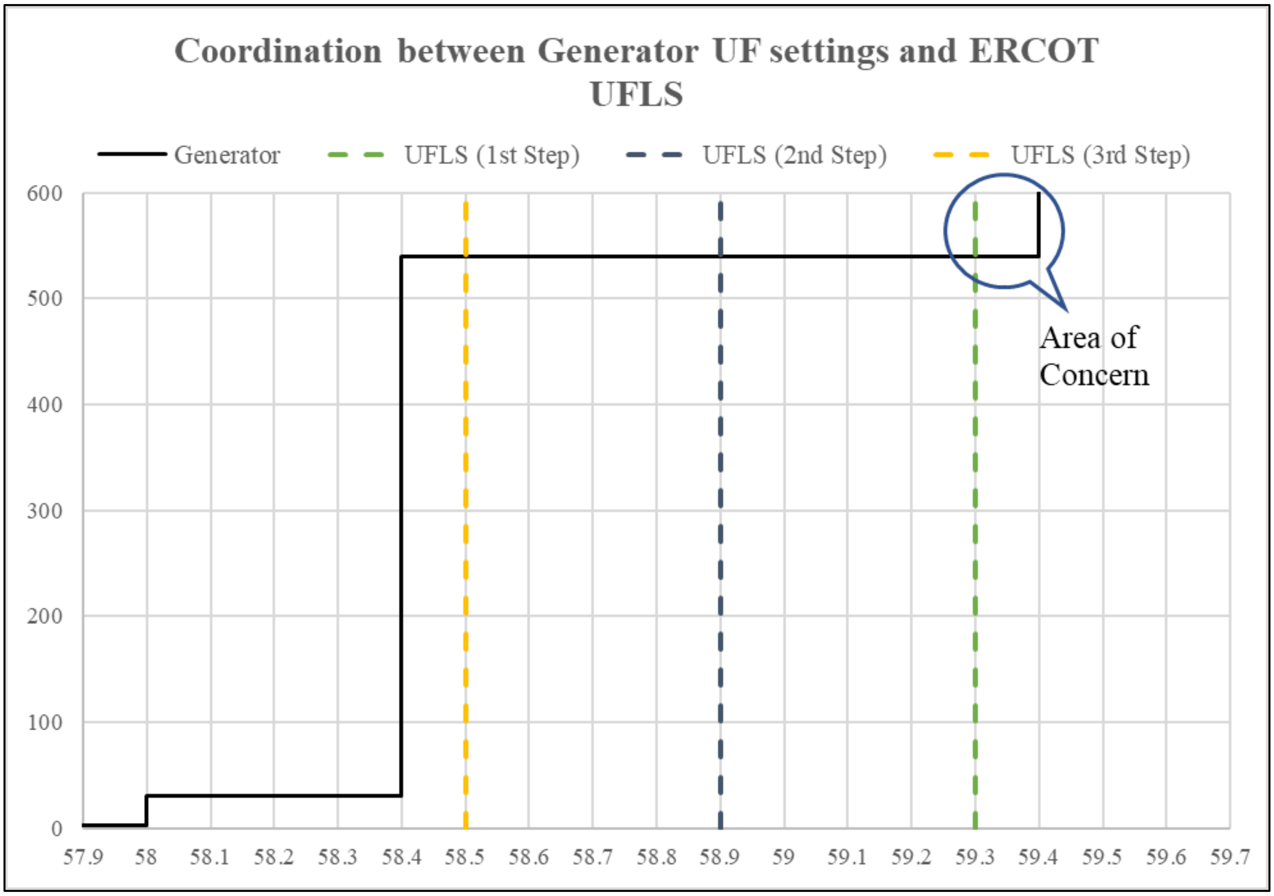
[358] PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings.

Figure 109: ERCOT System Frequency, February 15, 1:20 - 2:05 a.m.



As shown in Figure 110 below, load is typically tripped by underfrequency relays at setpoints higher than the prescribed generator underfrequency relay settings required by NERC Reliability Standard PRC-024. This practice is necessary to protect generators from low frequency condition and to minimize the risk of exposure of generating units to harmful vibrations and heat that can damage generation equipment if operating at low frequency for too long. The exception to this practice is the range between 59.3 Hz and 59.4 Hz in ERCOT, as shown in Figure 110. The coordination between generator and load underfrequency tripping in the 59.3-59.4 Hz range may exacerbate a declining frequency condition within ERCOT during BES disturbances. Therefore, a review of the coordination between current UFLS and generator frequency protection settings in ERCOT may be warranted.

Figure 110: Coordination between Generator Frequency Relays and ERCOT UFLS



<u>Recommendation 23</u>: Balancing Authorities, Reliability Coordinators and Transmission Operators should amend their outage and/or emergency operations procedures to reduce the time that Generation Owners/Generation Operators and Transmission Owners have to report generation and transmission derates and outages during declared emergency situations. This will better allow Balancing Authorities and Reliability Coordinators to identify trends (e.g., trends in facility outage or derate causes and magnitudes) during events where grid conditions are rapidly changing, to forecast future conditions and to prepare for potential system operator actions. The Balancing Authorities and Reliability Coordinators should also specify the mechanism by which the outages should be updated (e.g., phone call, system updates and outage tools). (Winter 2022-2023)

Transmission and BA and RC system operators rely on timely and accurate data for continued situational awareness and to support real-time operating decisions to maintain the stability and reliability of the BES. This exchange of data becomes more critical during extreme or abnormal operating conditions when it is necessary to implement emergency operating procedures.

For example, during the Event, as generating units within the ERCOT, SPP and MISO South were rapidly tripping or experiencing derates (e.g., section III.C.4.b - ERCOT Operator Actions: Maintaining Frequency Despite Generation Outages to Prevent Grid Collapse), owners and operators of generating units (e.g., QSEs in ERCOT, GOs/GOPs in SPP and MISO South) needed to provide up-to-date information to assist the BA system operators in determining the need for operator actions. While much of the BA system operators' data is continually updated automatically in real time/every few seconds (e.g., system frequency, actual generating units' MW outputs, tie-line MW flows) to provide situational awareness, data that was manually-updated, including changes in Physical Responsive Capability of generating units and additional information about outages (e.g., reason for outage, expected length of outage), was not manually updated by the GOs/GOPs frequently enough.

Along with the need for BAs to have an accurate status and forecast of available generating units' capabilities and availabilities,[359] RCs and TOPs need to have an accurate status and forecast of transmission facilities' capabilities and availabilities. The Event triggered numerous transmission facility outages, causing TOs to submit a large volume of manually-updated information (as with GOs/GOPs, this information included causes of outages and estimates of restoration time).

While requiring decreased turnaround times for providing manually-updated information makes sense, BAs and RCs, in conjunction with GOs/GOPs and TOs, should also implement automation to eliminate manual updates where possible. For example, ERCOT could implement a method to automatically reassign a tripped or derated generating unit's share of Physical Responsive Capability to other online generating units, so that the total Physical Responsive Capability would remain accurate.

[359] "It is critical for ERCOT [BA operators] . . . to have an accurate value of PRC at all times as well as an accurate forecast of available generation capability and availability." ERCOT Nodal Protocol Revision Request, Number 1085 (June 30, 2021) Nodal Protocol Revision Request (NPRR) 1085 (proposing to require resources including generating units to update their status within five minutes at the latest).

VII. Recommendations for Further Study

<u>Recommendation 24</u>: Federal and state entities with jurisdiction over natural gas infrastructure should cooperate to further study and enact measures to address natural gas supply shortfalls during extreme cold weather events,[360] including:

- **possible investments in strategic natural gas storage facilities, which could be located to serve the majority of pipelines supplying natural gas-fired generating units, and preserved for use during extreme cold weather events;**
- **possible financial incentives for the natural gas infrastructure system necessary to support the Bulk Electric System to winterize or otherwise prepare to perform during extreme cold weather events;**
- **possible options for increased regasification of Liquid Natural Gas (including possible Jones Act waivers); and**
- **market/public funding for Generator Owners/Generator Operators to have firm transportation and supply and invest in storage contracts. Such funding may need to finance the infrastructure (e.g., pipeline or storage expansion) necessary to provide additional firm transportation capacity, because many existing pipelines were financed and constructed to serve Local Distribution Companies and may not have sufficient additional firm capacity. Because many pipelines were financed and constructed to serve Local Distribution Companies and may not have sufficient existing firm capacity to support an increase in demand from Generator Owners/Generator Operators, studies could also examine whether additional infrastructure would be needed to meet that demand.[361] (Winter 2023-2024)**

The Event demonstrated the significant impacts a natural gas supply shortage can have, contributing to billions of dollars in damages and over 200 deaths. This Recommendation suggests further study, followed by state and/or federal entities with jurisdiction over natural gas infrastructure determining whether it might be cost-effective to invest in preventive measures to address some of the issues that played a central role in the Event, such as natural gas production declines or the contractual limits that resulted in some natural gas-fired generating units being outaged or derated. The Team suggests a few topics for consideration by the policymakers, but does not intend to limit the topics for consideration by those studying the natural gas supply shortfalls during cold weather events. Regulations or incentives could be used to encourage more natural gas producers to operate during freezing weather rather than performing preventive shut-ins. Incentives could be used for long-term improvements in natural gas infrastructure facility winterization, or in the short term to prepare for a storm by procuring needed supplies or supporting additional staffing. Policymakers could also consider how to encourage long-term investment into more natural gas storage facilities that are

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[360] These ideas are in addition to the possible topics in Recommendation 7. If the forum from Recommendation 7 determines that a topic needs additional study, it can be moved to this Recommendation.
[361] The Team acknowledges that promoting additional pipeline infrastructure may be contrary to certain federal and state policy goals.

strategically located, and their capacity reserved, to support natural gas-fired generation. Increased storage volumes could help to stabilize the natural gas market during supply shortfalls. Market or government incentives may also help encourage or support efforts by generating units to procure firm natural gas commodity and transportation contracts.

Recommendation 25: ERCOT should conduct a study to evaluate the benefits of additional links between the ERCOT Interconnection and other interconnections (Eastern Interconnection, Western Interconnection, and/or Mexico) that could provide additional reliability benefits including:

- **increased ability to import power when its system is stressed during emergencies, and**
- **improved black start capabilities. (Winter 2023-2024)**

Recommendations 25 and 26, below, both arose from observations about the performance of ERCOT's black start units during the Event. "Black start" refers to restarting the system after a major portion of the electrical network has been de-energized, and generators that have black start capability are those that can be started independently and without external power. ERCOT does not have any synchronous connections to the Eastern Interconnection, Western Interconnection, or Mexican grid. ERCOT's Interconnection has approximately 1,220 MW of asynchronous direct current ties to SPP (820 MW) and Mexico (400 MW). Recommendation 25 suggests the possibility that, in a similar event, ERCOT may not be able to facilitate a re-start of the grid given the combined unavailability of black start and natural gas-fired generating units. Thus, it recommends that ERCOT study the benefits of additional links between ERCOT and the other Interconnections.

ERCOT's study of additional links should take into account simultaneous extreme system conditions on adjacent systems to determine the feasibility of transferring imports over the transmission systems in the adjacent interconnections, and should identify any system enhancements needed to support the potential new links.[362] This study could potentially incorporate data or findings from the studies prepared in response to Recommendation 20 (perform bi-directional seasonal transfer studies).

Additional connections to the Eastern and Western Interconnections would enable ERCOT to increase its ability to import power when its system is stressed during emergencies, such as unexpected generating unit outages during extreme weather. Connections to the Eastern and Western Interconnections would also enable ERCOT to facilitate a restart of its interconnection using external transmission sources, in addition to its existing black start restoration process. Having access to additional imports could prove crucial if ERCOT experienced a blackout and had multiple black start generating units outaged, as was the case during the Event (see Recommendation 26, below). As part of its Roadmap to Improving Grid Reliability, ERCOT has a university research agreement to "assess the potential costs and benefits of increased transmission

[362] See 2018 Report, Recommendation 8.

both internal and external to ERCOT and increase coordination with other power regions," with initial results expected in first quarter 2022.

Recommendation 26: A joint FERC-NERC-Regional Entity team should study black start unit availability in the ERCOT footprint during cold weather conditions. The scope of the study should include:

- **an evaluation of ERCOT's existing black start restoration plan, including a review of potential single points of failure related to natural gas system dependence;**
- **the need for ensuring that generating units with dual-fuel capability providing black start service have appropriate fuel storage (as determined by the Balancing Authority);**
- **the need for requiring additional fuel storage due to import constraints;**
- **the need for Balancing Authorities to incorporate generating units' cold weather preparations into the qualification process for certifying generators as black start units; and**
- **the need for including a requirement for black start generators to test their fuel-switching capabilities seasonally. (Winter 2023-2024)**

Recommendations 25 and 26 both arose from observations about the performance of ERCOT's black start units during the Event. ERCOT procures black start resources every two years. ERCOT currently has a total of 28 (primary and alternate) black start resources within its footprint (100 percent use natural gas as their primary fuel, while some have an alternate fuel as well). At approximately 1:45 a.m. on February 15, six of the 28 black start capable units representing 14 percent of black start capacity were unavailable (four units totaling 169 MW of capacity were either forced outaged or failed to start and two units totaling 227 MW of capacity were derated by 73 MW). The greatest risk of a blackout was during this period, when ERCOT's system frequency was rapidly declining. Had a total blackout of the ERCOT system occurred during that time, the unavailability of black start resources would have hampered ERCOT's ability to promptly restore the system.

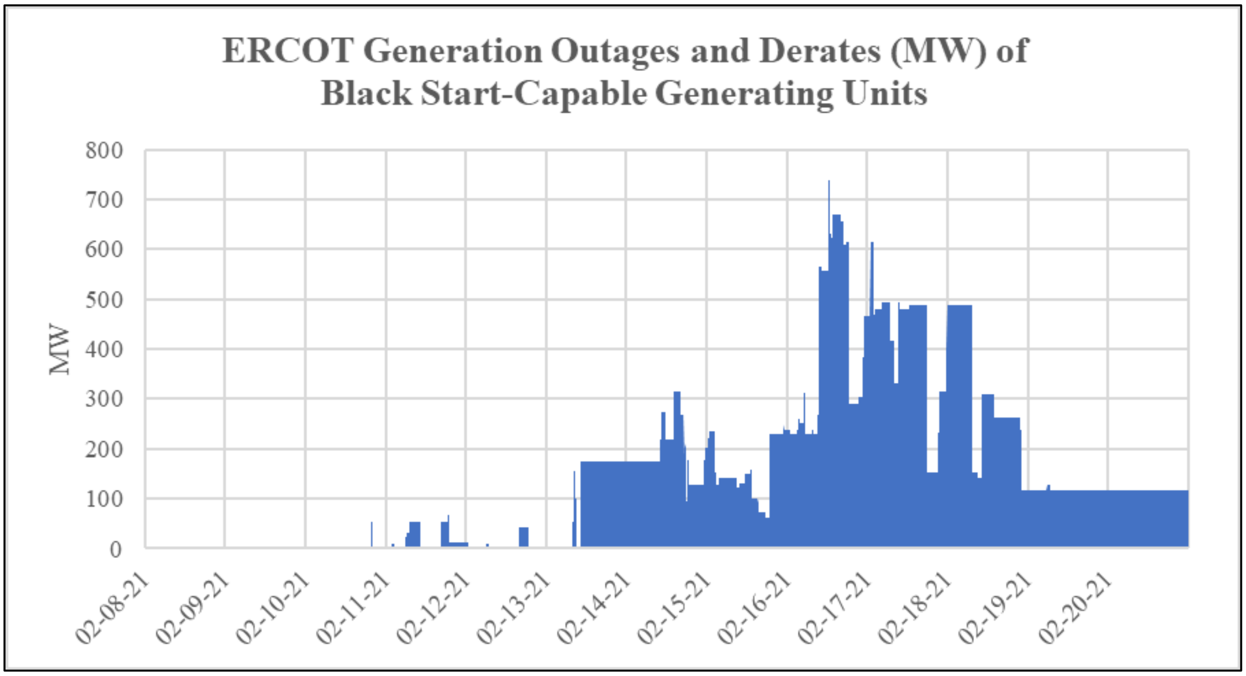
Over the course of the Event, 82 percent of ERCOT's 28 (primary and alternate) black start resources, comprising 1,418 MW out of a total 1,711 MW of black start capacity, experienced an outage, derate, or failure to start at some point. Forty-six percent of ERCOT's primary and alternate black start resources were either outaged, derated or failed to start due to freezing equipment issues (18 percent) or fuel limitations (39 percent) (see Figures 111 – 112, below). While prevention of recurrence of the Event is paramount, the Team also recognizes that ERCOT as a TOP is required to have a feasible system restoration plan, which depends on available and reliable black start resources to accomplish system restoration.[363] The high percentage of ERCOT black start units unavailable during the Event is cause for concern, even more so because ERCOT cannot rely on imports to restore its system in the event of a blackout. A study including the topics suggested by Recommendation 26 would enable ERCOT to improve the reliability of its restoration plan.

[363] *See* Reliability Standard EOP-005-3 – System Restoration from Black Start Resources.

Figure 111: ERCOT Black Start Unit MW Unavailability by Cause

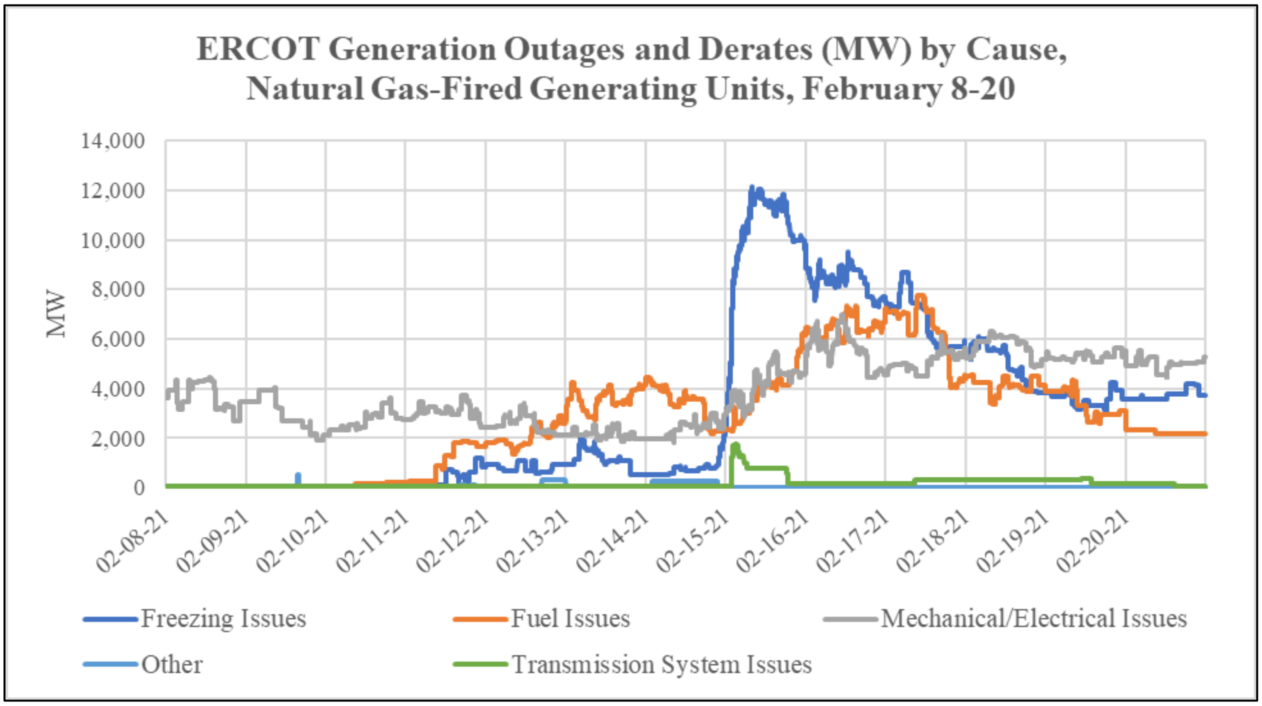
Black Start Unit Type	Freezing Issues	Fuel Issues	Mechanical/ Electrical Issues	Personnel Issues	Transmission System Issues
Gas Only	263	344	1,039	17	34
Gas/Oil	62	1,134	760		
Total	325	1,478	1,799	17	34

Figure 112: ERCOT Black Start Unit MW Unavailability by Date



During the Event, 58 percent of the generating units that experienced unplanned outages, derates or failures to start in ERCOT were natural gas-fired. These 336 units represented 57,780 MW of nameplate generation, and were responsible for 157,244 MW of the total MW outaged during the Event. Figure 113, below, shows how the causes of natural gas-fired generating unit outages and derates in ERCOT changed over time during the Event. Natural gas-fired generating unit outages and derates in ERCOT began with fuel issues starting February 11, and on February 15, when the coldest temperatures began, freezing issues increased especially sharply, but mechanical/electrical and fuel issues also escalated.

Figure 113: ERCOT Generator Outages, Derates, and Failures to Start (MW) by Cause, Natural Gas-Fired Generating Units, February 8-20, 2021



<u>Recommendation 27</u>: Beyond Recommendation 13 (Generator Owners within ERCOT review potential for units to trip due to low frequency or high rate-of-change of frequency conditions), the team recognizes that generating units tripping due to low frequency or high rate-of-change of frequency conditions could occur in the Eastern and Western Interconnections as well. Therefore, the team recommends that FERC, NERC, and the Regional Entities, in cooperation with Generator Owners, study the ERCOT low frequency event and past significant frequency disturbances. The study should consider the potential for protective relay settings associated with generator underfrequency relays, balance of plant relays, and tuning parameters associated with control systems on generating units to trip generating units during low frequency or high rate-of-change of frequency conditions in the other Interconnections, and determine the whether a new Reliability Standard is warranted, or whether other actions can best protect the reliability of the Bulk Electric System. (Winter 2022-2023)

One of the major issues associated with the Event was the low frequency disturbance on the ERCOT system on February 15 shortly before 2 a.m. Although low frequency is a threat to the reliability of the BES by itself, low frequency, or the rate of frequency change, also caused approximately 1,769 MW of coal generation and 2,190 MW of gas generation to trip or derate. For instance, a 933 MW coal unit tripped due to the rapidly-changing frequency on the grid, which affected the boiler controls and caused a high boiler pressure condition. As a result of the outages seen during the Event, the Team became concerned about the coordination of generator frequency protection with UFLS protection. NERC Reliability Standard PRC-024-2 requires generator owners to set protective relays so that generating units remain connected during defined frequency and voltage excursions. For ERCOT, PRC-024-2 requires a first step of generator underfrequency protection of not more than 59.4 Hz for not less than nine minutes. ERCOT experienced approximately four and a half minutes of operations below 59.4 Hz, but above the first step of UFLS protection set at 59.3 Hz. Given the nine-minute time requirement in the PRC-024-2 standard for a setpoint of 59.4 Hz, if ERCOT had remained below 59.4 Hz for an additional four and a half minutes it would have lost approximately 17,000 MW of generation due to UFLS and risked a potential blackout of the entire ERCOT Interconnection.

Generator model validation requirements in the NERC Standard MOD-027-1 require submission of verified turbine/governor models and load control or active power/frequency control models. The minimum frequency excursion criteria in MOD-027-1 is 0.10 Hz (at or below 59.90 Hz) for ERCOT and the Western Interconnection, and 0.05 Hz (at or below 59.95 Hz) for the Eastern Interconnection. Generator models at 59.90 Hz may not necessarily represent a unit's performance at the low frequencies near 59.30 Hz experienced during the Event. More data on generating unit behavior during past frequency disturbances, including the Event, and perhaps a period of additional data collection using a dedicated GADS code as recommended in Recommendation 13, will help to determine the whether a new Reliability Standard is warranted, or whether other actions can best protect the reliability of the BES.

<u>Recommendation 28</u>**: Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, Distribution Providers and one or more entities representing U.S. natural gas infrastructure[364] entities should jointly conduct a study to establish guidelines to assist natural gas infrastructure entities in identifying critical natural gas infrastructure loads[365] to manual and automatic load shedding entities, in order for the critical natural gas infrastructure loads to be protected from manual and automatic load shedding. The guidelines should establish identification criteria in a format which manual and automatic load shed entities can readily distribute to natural gas infrastructure entities they serve. Development of the guideline should include determining:**

- **whether there is a need to rank the types of critical natural gas infrastructure loads that are protected from manual and underfrequency load shedding for those situations in which the amount of load required to be shed does not allow for rotating load shed; and**
- **a means for periodic review and update of the guideline, to include considering whether the current criteria for identifying critical natural gas infrastructure loads are sufficient to avoid adversely affecting BES natural gas-fired generation. (Winter 2022-2023)**

This Recommendation is necessary to support Key Recommendation 1i, regarding the protection of critical natural gas infrastructure loads. Recommendation 1i would amend the Reliability Standards to require manual and automatic load shed entities, including TOPs, TOs, and DPs, to create and

[364] *See* footnote 29 for the definition of natural gas infrastructure.
[365] *See* footnote 278 for the definition of critical natural gas infrastructure loads.

distribute criteria to natural gas infrastructure entities for identifying critical natural gas infrastructure loads.

Although natural gas infrastructure loads that will actually have an adverse effect on BES natural gas-fired generating units if de-energized need protection from manual load shedding, it is equally important not to designate too many natural gas infrastructure loads as critical. Every load that is designated as critical results in a distribution circuit that cannot be used for manual load shedding, increasing the burden on the remaining circuits. Creating effective criteria will require cooperation among entities with knowledge of the grid and entities with knowledge of natural gas infrastructure. Grid entities such as TOPs, TOs and DPs should collectively know which electric circuits serve natural gas infrastructure entities' facilities, which of those circuits are already protected due to other critical loads or automatic load shedding/UFLS, their current critical load identification processes and any current associated criteria for identification within their respective service areas. Natural gas infrastructure entities can obtain information to identify which of their facilities and equipment are most critical to producing, processing, and delivering natural gas to specific BES generating units (identified by the RCs/BAs), and can also assist in translating what could start as highly technical information into criteria that can be easily understood by the target audiences. And, in addition to identifying the BES natural gas-fired generating units within the BAs' respective footprints for the natural gas infrastructure entities, the RCs /BAs can help natural gas infrastructure entities understand how natural gas-fired generating units are committed and dispatched to provide for BES reliability, especially during constrained winter peak conditions.

Figure 114: Table of Recommendations with Assigned Timeframes for Implementation

Recommendation Topic	#	Timeframe for Implementation[366]
Key Recommendations		
Cold Weather Critical Components	1a,b	2023-2024
Account for Effects of Precipitation and Wind	1c	2023-2024
Corrective Action Plans for Freeze-Related Causes	1d	2022-2023
Annual Training on Cold Weather Plans	1e	2022-2023
Operate to Specified Ambient Temperature, Weather	1f	2022-2023
Generator Capacity to Rely Upon during Cold Weather	1g	2023-2024
Generator Compensation Opportunities for Investments	2	2022-2023
Generator Winter Readiness Technical Conference	3	2022-2023
Freeze Protection Inspection and Maintenance Timing	4	2022-2023
Natural Gas Facility Cold Weather Preparedness Plans	5	2022-2023

[366] For mandatory Reliability Standards, implementation means that new and/or revised Standards that address the recommendation are proposed to the Commission for approval within the timeframes listed with the recommendations. In the FERC-approved NERC Rules of Procedure, Appendix 3A Standard Processes Manual, NERC can deviate from its normal process when necessary to meet an urgent reliability issue. *See* https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

Natural Gas Facility Freeze Protection Measures	6	2022-2023
Establish Natural Gas -Electric Reliability Forum	7	2022-2023[367]
Understanding Generator Natural Gas Contract Risks	8	2021-2022[368]
Use of Demand Response - Natural Gas Infrastructure	1h	2023-2024
Protect Identified Critical Natural Gas Infrastructure	1i	2023-2024
Overlap of Manual and Automatic Load Shed/UFLS	1j	2022-2023
Peak Load Forecasts and Reserve Margin Calculations	9	2023-2024
Other Recommendations		
Improve Rotational Load Shed Plans	10	2023-2024
Cold Weather Effects-Mechanical, Electrical Systems	11	2023-2024
Generator Use of Weather Forecasts for Operating Plans	12	2021-2022
ERCOT Generators to Review Low-Frequency Effects	13	2022-2023
Natural Gas Production Facilities SCADA Control	14	2023-2024
Develop or Enhance Emergency Response Centers	15	2022-2023
Improve Near-term Load Forecasts	16	2022-2023
Analyze Intermittent Generation to improve Load Forecast	17	2022-2023
Additional Rapidly-Deployable Demand Response	18	Beyond 2023-2024 but ASAP
Retail Incentives for Energy Efficiency Improvements	19	Beyond 2023-2024 but ASAP
Perform Bi-Directional Seasonal Transfer Studies	20	2022-2023
Operator-Training Rotational Firm Load Shed Simulations	21	2022-2023
Generator Protection Settings/ UFLS Coordination	22	2023-2024
Report Times for Generation and Transmission Outages	23	2022-2023
Recommendations for Further Study		
Measures to Address Natural Gas Supply Shortfalls	24	2023-2024
Additional ERCOT Interconnection Links	25	2023-2024
ERCOT Black Start Unit Reliability	26	2023-2024
Low-Frequency Effects in Eastern, Western Interconnects	27	2023-2024
Guidelines to Identify Critical Natural Gas Facility Loads	28	2022-2023

[367] Implementation for this Recommendation means that the forum has been identified, and the participants and dates for the technical conferences or meetings have been scheduled.
[368] Although the related Reliability Standard is not proposed to be in effect for winter 2021-2022, the Team recommends that GOs voluntarily implement this Recommendation before winter 2021-2022.

APPENDICES

Appendix A: February 2021 Cold Weather Grid Operations Inquiry Joint Team Members

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Appendix B: Comparison of Similar Severe Weather Events[369]

This section compares select extreme cold weather events that have occurred in the U.S. over the past 40 years, to gain understanding of the characteristics of these weather systems and how they can vary, including their temperature variations, their durations, and other weather conditions including precipitation and wind. Five severe cold weather events that impacted south central U.S. and Texas are compared: December 1983, December 1989, February 2011, January 2018, and February 2021. Understanding the characteristics of these weather events are necessary for aiding in the development of cold weather preparedness plans and cold weather protection measures needed for electric and natural gas infrastructure facilities that are critical in supporting bulk-power system reliability - i.e. determining the levels/measures of protection in order to keep facilities operable, maintain their operation throughout the extreme cold weather.

A. Seasonal Timing of Cold Weather Events

In the continental U.S., we commonly think of the winter cold weather months as being December, January, and February. It is also commonly thought that January is the coldest month of those three, and indeed cold weather periods in parts of the U.S. during January are typical. From review of the five extreme cold weather events:

- two events occurred in December,
- one event occurred in January, and
- two events occurred in February.

Two of the five that were the coldest for the longest durations in south central U.S. and Texas occurred the at the earliest and latest times during the winter season as compared to the other events. The earliest that occurred was the December 1983 cold weather event (December 15-30) and the latest was the February 2021 cold weather event (February 8-20). The timing of *when* these extreme cold weather events occurred indicate that being prepared (implementation of infrastructure cold weather preparedness plans and freeze protection measures) for extreme cold weather needs to take place *before* cold weather has been known to occur for the infrastructure/facility locations, and likewise the measures need to remain in place and functional for the entire timeframe that extreme cold weather has been known to occur.

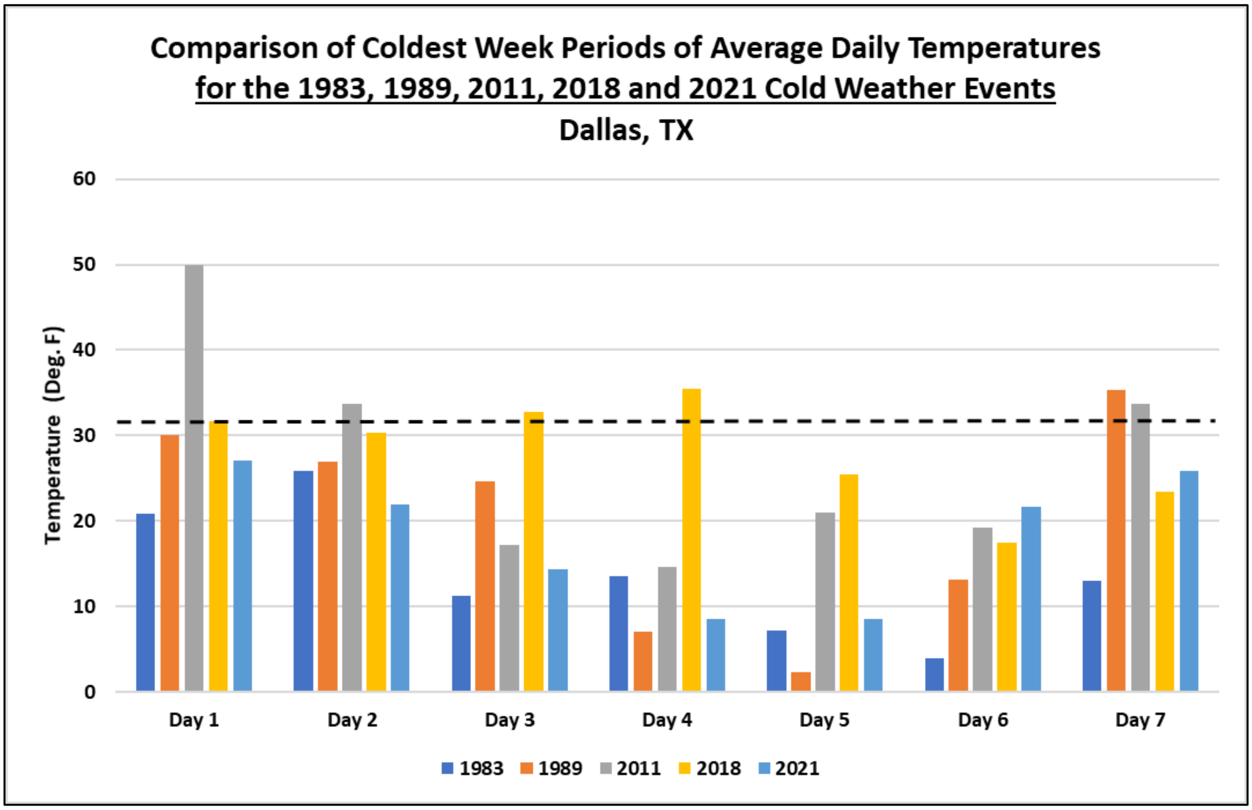
[369] The Team thanks NOAA's National Weather Service – Weather Prediction Center for weather analysis support it provided.

B. Temperature and Duration Comparison

The following charts (Figures 90 – 92) compare average daily temperatures[370] for one-week periods which occurred during each cold weather event for select locations in south central U.S.:

- 1983 cold weather event, week of December 20 – 26
- 1989 cold weather event, week of December 19 – 25
- 2011 cold weather event, week of January 31 – February 6
- Both the cold weather event, week of January 12 – 18
- 2021 cold weather event, week of February 12 – 18

Figure 115: Temperature Comparison – Dallas, TX



[370] It is important to recognize that for a given average daily temperature, that there temperatures typically during the nighttime and early morning hours that may be below, and during the daytime that may be above the average daily temperature value. The team recommends extreme cold ambient temperature analysis by infrastructure entities include review of historic minimum temperatures for aiding in determining levels of freeze protection measures.

Figure 116: Temperature Comparison – Houston, TX

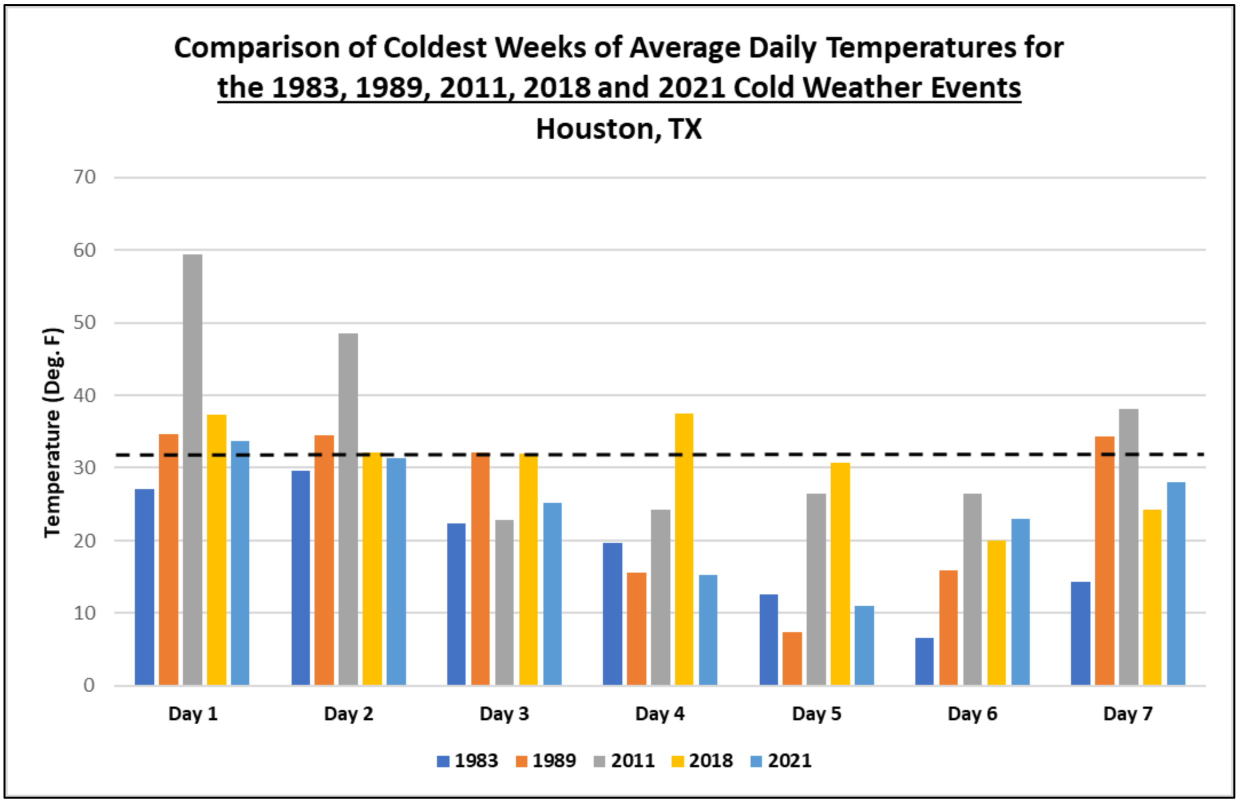
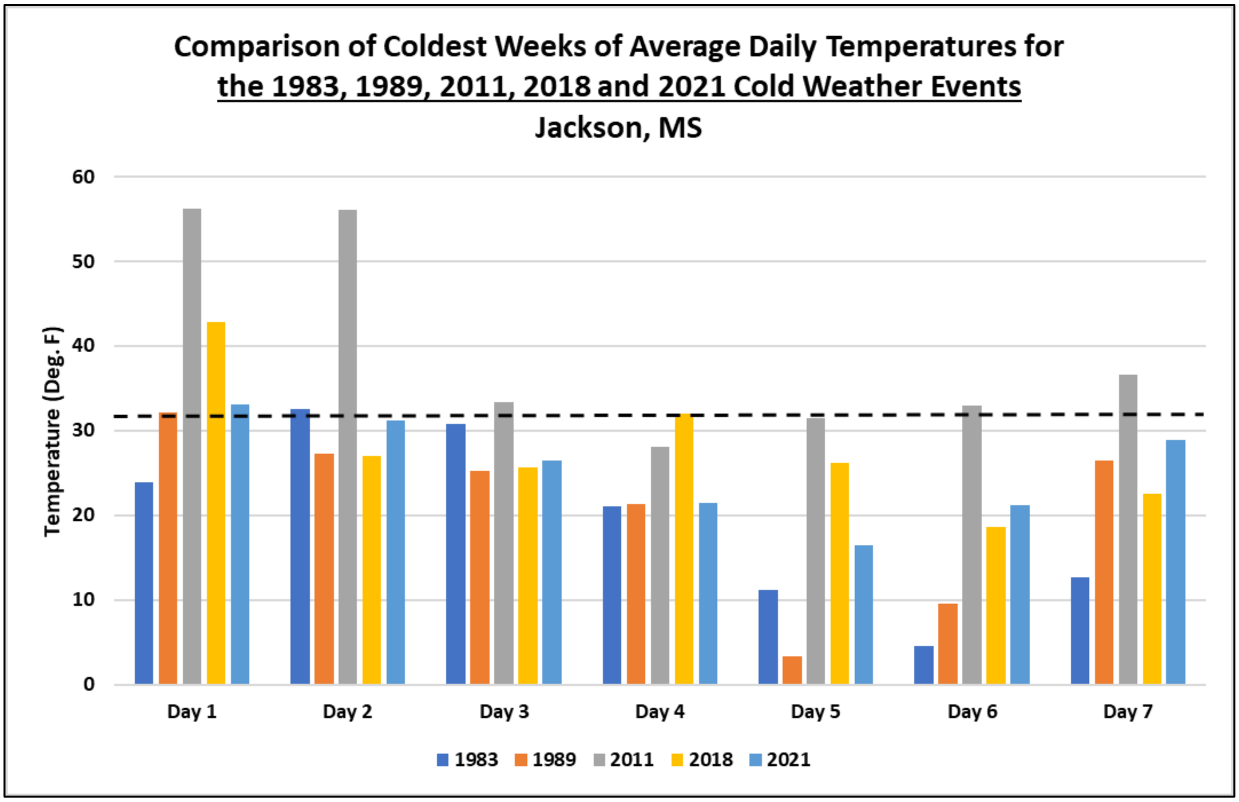


Figure 117: Temperature Comparison – Jackson, MS



The charts above provide the following insights regarding temperatures and durations.

Cold Temperatures

- Dallas, Houston, and Jackson, for at least one of the five events, each experienced at least one day where the **average daily temperature was below 10 Deg. F**, and
- Dallas, for three of the five events, experienced at least one day for each of the week-long periods where the **average daily temperature was below 10 Deg. F.**
- Houston and Jackson, for two of the five events, experienced at least one day for each of the week-long periods where the **average daily temperature was below 10 Deg. F.**
- Dallas and Jackson, for two of the five events, experience at least one day for each of the week-long periods where the **average daily temperature was below 5 Deg. F.**

Duration

- For Dallas, Houston, and Jackson, for all five events, **average daily temperatures were at or below 32 Deg. F for at least three days** out of the week-long periods,
- For Dallas, for three of the five events, **average daily temperatures were at or below 20 Deg. F for three consecutive days**, and
- For Houston and Jackson, for two of the five events, **average daily temperatures were at or below 20 Deg. F for two consecutive days**.

- In comparing below-freezing temperatures and durations, the following table contains other noteworthy statistics and observations about the cold weather events.

Figure 118: Temperature Comparison Statistics and Observations

Cold Weather Event	Duration of event	Low temp.	Noteworthy observations
1983	12.3 days below freezing DFW 6.2 days below freezing Waco, TX 5 days below freezing Houston	5 F at DFW 7 F at Waco Airport -2 F at Glen Rose 2W	7 separate cold fronts during this event
1989	14 nights below freezing over 2-3 weeks in Houston	2 F at College Station 7 F in Houston 14 F in Galveston	Coldest recorded winter for the Galveston/Houston area.
2011	5 days below freezing 12 nights below freezing over 2 weeks in Houston	17 F in Dallas 20 F in Houston	
2018	3 nights below freezing in TX and LA 7 nights below freezing in MS, AR, TN		This event was most severe east of Texas.
2021	6 days, 20 consecutive hours below freezing	6 F in Austin 8 F in Dallas 10 F in Houston	Most similar to 1983 event in long period of cold with multiple fronts affecting a wide swath of the U.S.

C. Precipitation Comparison

This section compares the level of and types of precipitation which occurred during each cold weather event in south central U.S. and Texas. It is noteworthy that for most of the events, freezing precipitation (in form of freezing rain, sleet, and/snow) conditions occurred during the leading edge of each extreme cold weather front, where the colder temperatures followed the freezing precipitation timeframe. Therefore, the precipitation timeframes for the five events below may include days ahead of or may be within the cold temperature week periods in Section B, above:

- 1983 cold weather event (December 15 – 30)
- 1989 cold weather event (December 21 – 24)
- 2011 cold weather event (February 1 – 3)
- 2018 cold weather event (January 14 – 17)
- 2021 cold weather event (February 11 – 19)

Figure 119: Precipitation Comparison

Cold Weather Event	Precipitation Summary
1983	December 15-16: Severe cold and snow storm (8+ inches) in northern Texas; multiple cold fronts occurred in north Texas through the end of December, with sub-freezing temps and snow lasting throughout the month.
1989	December 21-24: Three severe cold fronts move into Texas; precipitation was minimal with a narrow band of snow north of Austin, Texas. Overall, precipitation was not much of a factor in the southern plains during this cold weather event of 1989
2011	February 1-3: Widespread heavy snow with blizzard conditions, combined with significant freezing rain and sleet ranging from northern Texas through the upper Midwest and into New England; snowfall amounts of 10-20 inches were recorded from the Midwest to New England along with high winds; Snowfall in northern Texas was 1-4 inches, with a few smaller areas in north Texas having up to 8 inches.
2018	January 14-17: Winter Storm Inga brought snow and ice to parts of the Midwest, South and Eastern U.S. on January 14-17. The upper Midwest experienced 2-5 inches of snow and the Gulf States from Texas to Alabama experienced 1-2 inches of snow accumulation and icy conditions.
2021	February 11-19: The southern plains experienced three waves of precipitation during a 7 day period; February 11-12: Freezing rain and snow in Texas and severe heavy rain in Louisiana and Mississippi; February 14-16: Heavy freezing rain and snow hits the southern plain states combined with severe cold temps; February 17-19: Addition snow and freezing rain occur across the southern plain states with Oklahoma and Arkansas receiving significant accumulations of snow and ice.

In summary:

- the majority (four out the five) severe cold weather events' characteristics included some form of freezing precipitation (freezing rain and/or snow),
- three of those four cold weather events also included freezing rain precipitation, and
- three of those four cold weather events included significant snowfall for the region.
- Based on the fact that freezing precipitation is likely to occur during extreme cold weather events warrants that freeze protection measures should be weather or water-proofed to mitigate the risks caused by frozen precipitation.

D. Wind Comparison

This section describes the commonalities across some outbreaks of Arctic air across the Southern United States. The graphics show the composite mean wind speeds for a 7-day period, and the tables are a snapshot at designated metropolitan locations. With respect to wind conditions, the February 2021 cold weather event was not as extreme of a weather event when compared to other cold weather events at similar locations, although along the gulf coast, there were stronger wind conditions than at other locations.

Wind conditions during the 1983 cold weather event. During the week of December 20 – 26, there were northerly, north westerly, and north easterly winds at average speeds of 0 – 9 mph in the Southern United States ranging from Texas to the East Coast. On the coldest day of that week, the average wind speeds ranged from 9 – 19 mph with peak wind gusts of 34 mph.

Wind conditions during the 1989 cold weather event. During the week of December 19 – 25, there were northerly winds at average speeds of 0 – 9 mph in the southern United States. In addition, East Texas and Louisiana had average wind speeds that reached up to 9 – 13 mph and over half of the state of Louisiana had average wind speeds that reached up to 13 – 18 mph. On the coldest day of that week, the average wind speeds ranged from 5 – 17 mph with peak wind gusts of 34 mph.

Wind conditions during the 2011 cold weather event. During the week of January 31 – Feb 6, most of the Southern United States had northerly and north westerly winds at speeds of 0 – 9 mph. North and north central Texas had winds at speeds of 9 – 18 mph. On the coldest day of that week, the average wind speeds ranged from 10 – 18 mph with peak wind gusts of 31 mph.

Wind conditions during the 2018 cold weather event. During the week of January 12 – 18, most of the Southern United States had northerly and north westerly winds at speeds of 0 – 9 mph. In addition, there were northerly, north easterly, and north westerly winds at speeds of 9 – 13 mph in East Texas, Arkansas, Louisiana, Mississippi, and most of Oklahoma. Central and West Louisiana had northerly winds at speeds of 13 – 18 mph. On the coldest day of that week, the average wind speeds ranged from 5 – 17 mph with peak wind gusts of 32 mph.

Wind conditions during the 2021 cold weather event. During the week of February 12 – 18, there were north easterly winds at speeds of 9 – 22 mph in Oklahoma, Arkansas, Texas, half of Louisiana, and half of Mississippi. On the coldest day of that week, the average wind speeds ranged from 6 – 19 mph with peak wind gusts of 41 mph. In Dallas, the wind direction shifted throughout the day, ranging from the northwest to the southeast.

Figure 120: Cold Weather Event Wind Speeds (mph) for the Coldest Average Temperature Day for Each Location

Cold Weather Event ->	**1983**		**1989**		**2011**		**2018**		**2021**	
	Avg.	Gust	Avg.	Gust	Avg.	Gust	Avg.	Gust	Avg.	Gust
Dallas	19	34	16	34	18	31	17	32	7	21
Houston	13	25	13	28	16	29	10	25	19	38
Lake Charles	12	20	15	28	14	29	5	18	16	41
Little Rock	14	34	7	15	13	24	13	25	6	16
Jackson	12	23	17	22	10	23	10	25	6	19

In summary:

- All five severe cold weather events' possessed moderate[371] wind conditions for the majority of the above locations in south central U.S. and Texas,
- Average wind speeds for each of the five locations across all five events ranged from 10 to 15 mph.
- Average wind gusts for each of the five locations across all five events ranged from 22 to 30 mph.
- Based on the above analysis, substantial wind conditions are likely to occur during extreme cold weather events. This condition warrants that infrastructure/facility freeze protection measures should also be protected to mitigate the risks caused by accelerated heat loss due to wind.

[371] *See* https://www.weather.gov/pqr/wind.

Appendix C: Examples of Alerts and Notices Issued by Electric and Natural Gas Entities During Event

Figure 121: Example Reliability Coordinator (RC) Notice Issued February 12, 3:53 p.m.

Notification

[MISO] MISO declares Conservative Operations for Reliability Coordinator Footprint effective 02/14/2021 12:00 EST

***Declaring Conservative Operations due to extremely cold temperatures and generator fuel supply risks.

The MISO Reliability Coordinator (RC) is declaring Conservative Operations, effective from 02/14/2021 12:00 EST to 02/16/2021 23:59 EST for the following entities: Reliability Coordinator Footprint and instructs that:

- All transmission and Generation maintenance is suspended in the affected area for the duration of the Conservative Operations period, unless such maintenance will result in improved Bulk Electric System (BES) monitoring, control and security. Such maintenance will be coordinated between MISO and the applicable entity. The return to service of equipment on outage should be coordinated between MISO and the applicable entity. MISO Outage Coordination may permit on a case-by-case basis specific transmission maintenance that does not impact the Bulk Electric System.
- Transmission Operators (TOPs) and Generation Operators (GOPs) in the affected area, in coordination with the MISO and their Local Balancing Authority (LBA), are to review outage plans to determine whether any maintenance or testing, scheduled or being performed on any monitoring, control, transmission or generating equipment can be deferred or cancelled.

Figure 122: Example Natural Gas Pipeline Notice Posted February 14, 8:30 a.m.

Northern Natural Gas
A BERKSHIRE HATHAWAY ENERGY COMPANY

Printable Version

TSP Name: Northern Natural Gas Company	**SMS %:** Field 0%, Zone ABC 0%, Zone D 0%, Zone EF 0%
TSP: 784158214	**Post Date/Time:** 02/14/2021 08:30 AM
Notice ID: 058558	**Notice Effective Date/Time:** 02/15/2021 09:00 AM
Notice Type: Operational Alert/Critical Day	**Notice End Date/Time:** 02/16/2021 08:59 AM
Subject: CRITICAL DAY FOR GAS DAY FEBRUARY 15, 2021 – ENTIRE SYSTEM	**For Gas Day(s):** 02/15/2021
Critical: Y	**Notice Status:** Initiate
Location: ALL MARKET AND FIELD AREAS	**Required Response Indicator Description:** 5-No response required
MID / Zone: 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16A, 16B, 17, ABC, D, EF	

Notice Text:

Due to the severe weather conditions experienced in Northern's Market and Field Areas and significant natural gas price volatility, Northern is calling a Critical Day applicable to delivery points located in all Market Area zones and Field Area MIDs effective for the Gas Day beginning at 9 a.m. on Monday, February 15, 2021. The significance of a Critical Day being called is if a shipper takes deliveries from the pipeline in excess of scheduled quantities, such shipper may incur higher penalties as set forth on Tariff Sheet No. 53 and the DDVC rates page on Northern's website .

Northern's system-weighted average wind-adjusted temperature is forecast to be -10 degrees for Monday, February 15, 2021, and is forecast well below normal through the weekend. Northern's normal system-weighted temperature is 20 degrees. Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects in its Market and Field Areas. It is uncertain when this situation will improve. As this situation continues, Northern's pipeline system integrity will be negatively impacted if deliveries are in excess of receipts, resulting in low line pack levels across the entire system. For the weekend trading block that extends from Gas Day Saturday, February 13 through Tuesday, February 16, 2021, the average Northern Demarc and Northern Ventura prices were $231.67/Dth and $154.905/Dth, respectively. The MIP price for February is unknown at this time. The Critical Day penalties are intended to deter any incentive for actual market deliveries to be above scheduled quantities.

Due to cold weather conditions impacting the Market and Field Areas, Northern expects to have limited operational flexibility to accommodate underperformance at receipt points. If underperformance occurs at any receipt points, Northern may be required to allocate these points to actual flowing volumes. Northern will continue to monitor points across the system in order to protect the pipeline's integrity.

Refer to Tariff Sheet No. 291 for information related to Critical Day provisions.

Please continue to monitor Northern's website for updates.

If you have any questions regarding this notice, please contact your marketing or customer service representative.

DDVC penalties are applicable to the bumped shipper's quantity.

Appendix D: Other Unplanned Generation Outages During Event by Fuel Type (Coal, Nuclear, Solar, Other)

Figure 123: Causes of Unplanned Generation Outages and Derates for Coal -Fired Units (by Number of Outages), Total Event Area, February 8-20

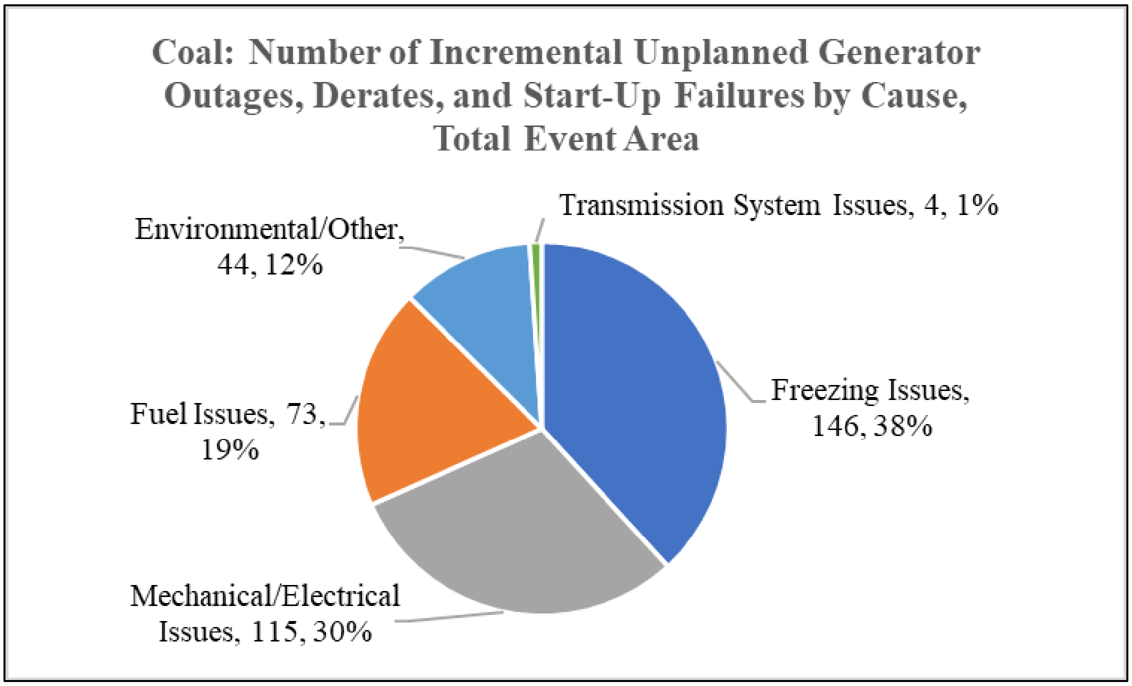


Figure 124: Causes of Unplanned Generation Outages and Derates for Coal -Fired Units (by Outaged MW), Total Event Area, February 8-20

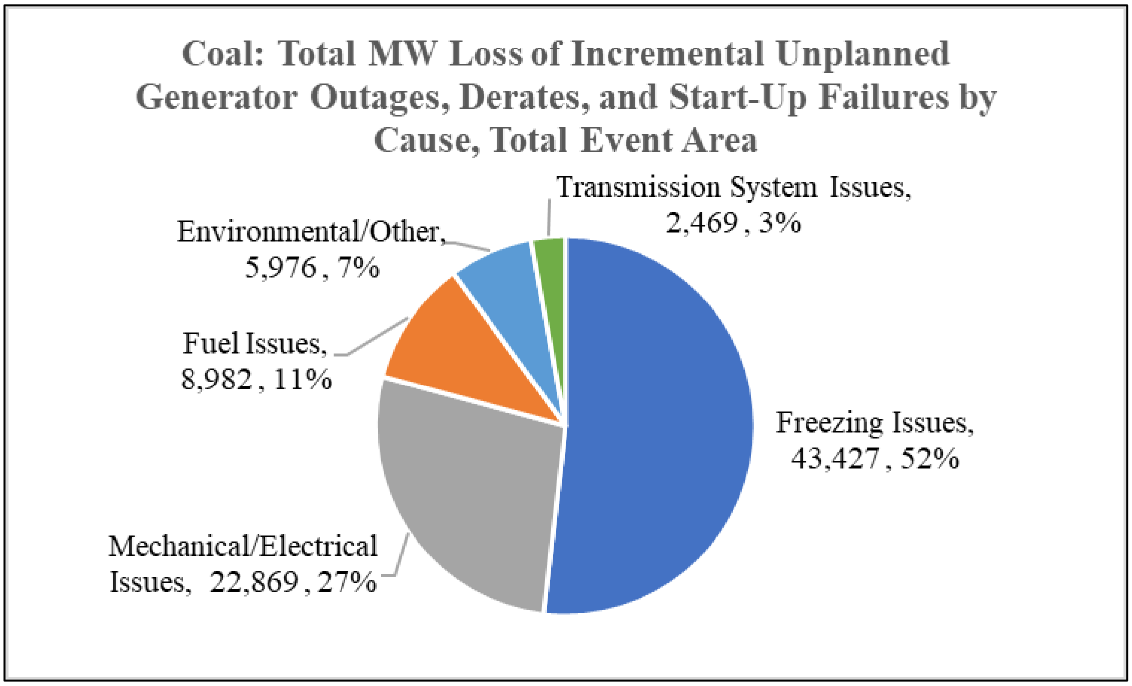


Figure 125: Causes of Unplanned Generation Outages and Derates for Nuclear Units (by Number of Outages), Total Event Area, February 8-20

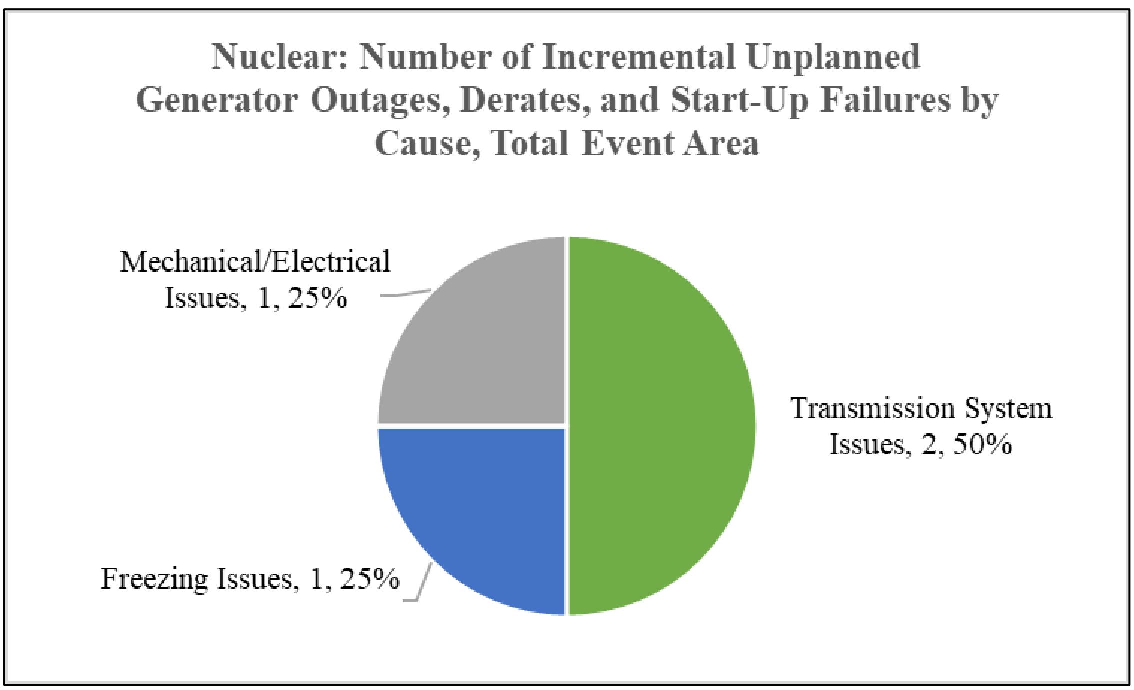


Figure 126: Causes of Unplanned Generation Outages and Derates for Nuclear Units (by Outaged MW), Total Event Area, February 8-20

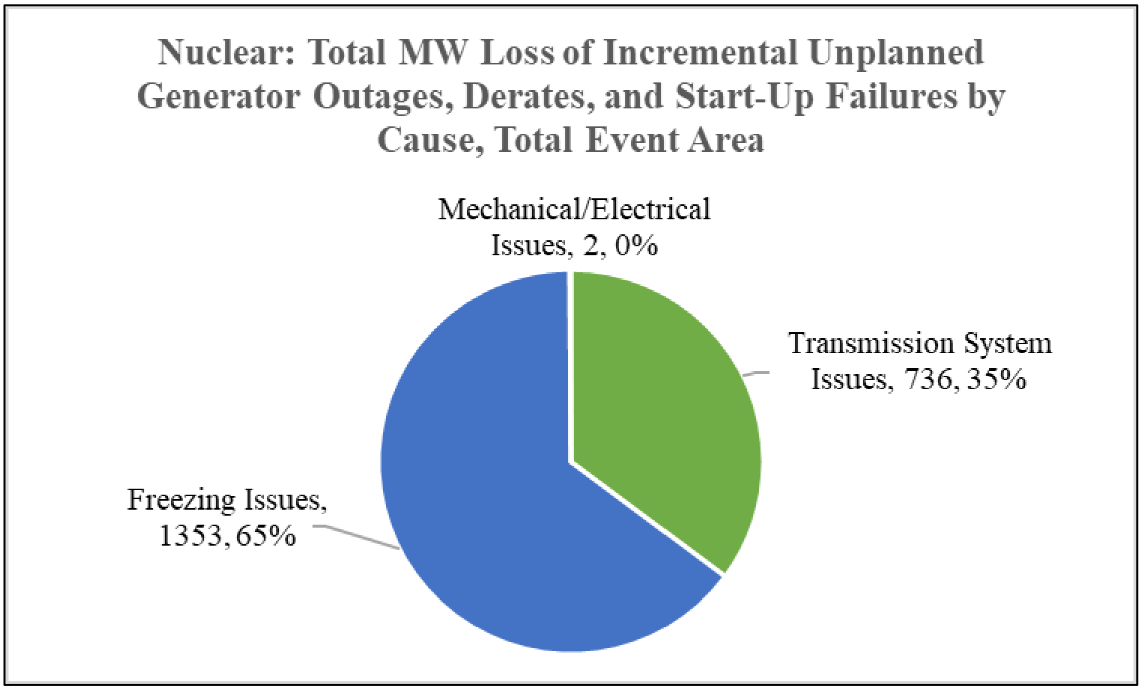


Figure 127: Causes of Unplanned Generation Outages and Derates for Solar Resources (by Number of Outages), Total Event Area, February 8-20

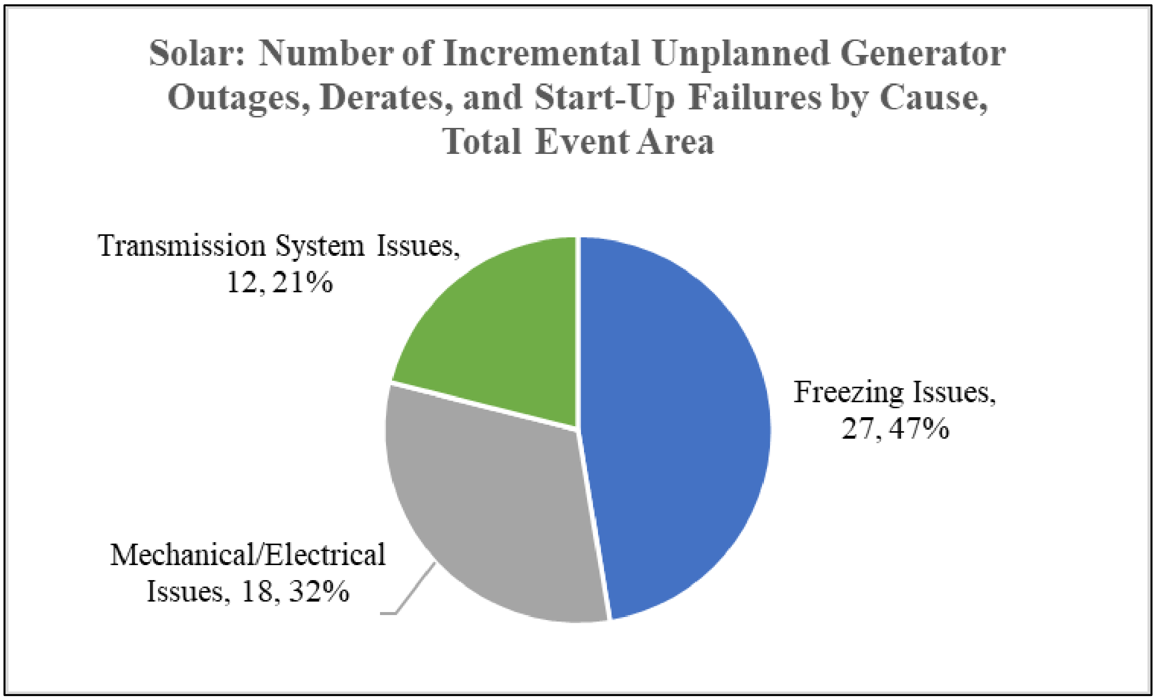


Figure 128: Causes of Unplanned Generation Outages and Derates for Solar Resources (by Outaged MW), Total Event Area, February 8-20

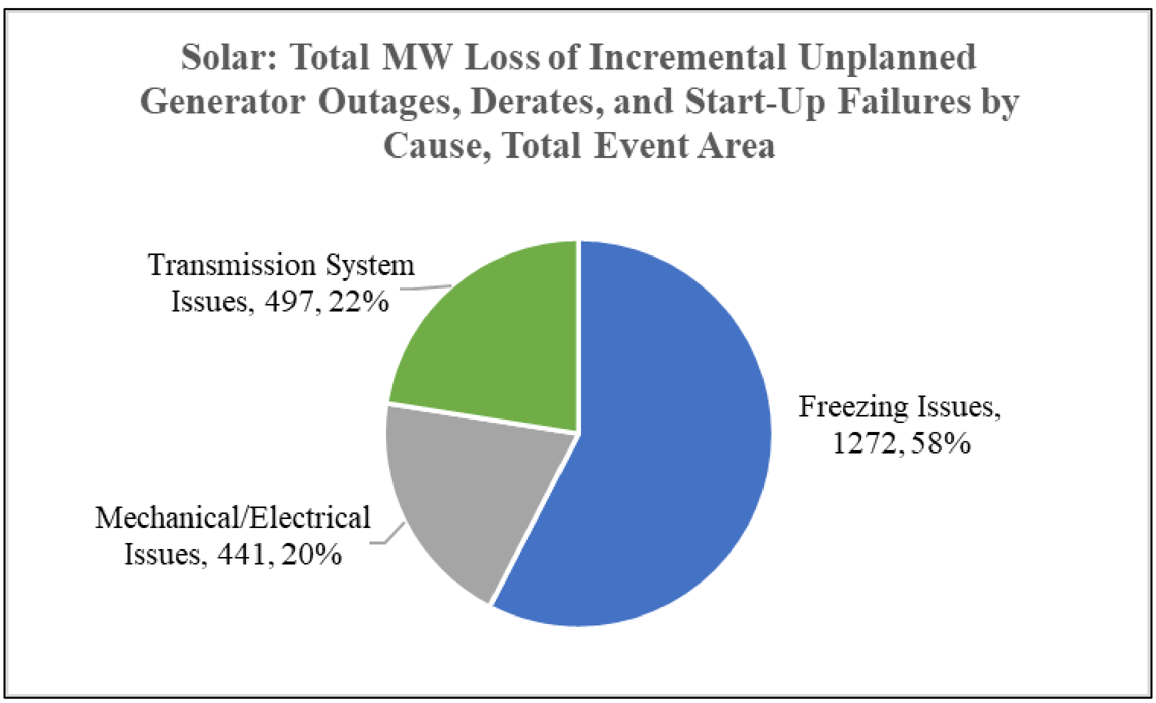


Figure 129: Causes of Unplanned Generation Outages and Derates for Other Fuel Types (by Number of Outages), Total Event Area, February 8-20

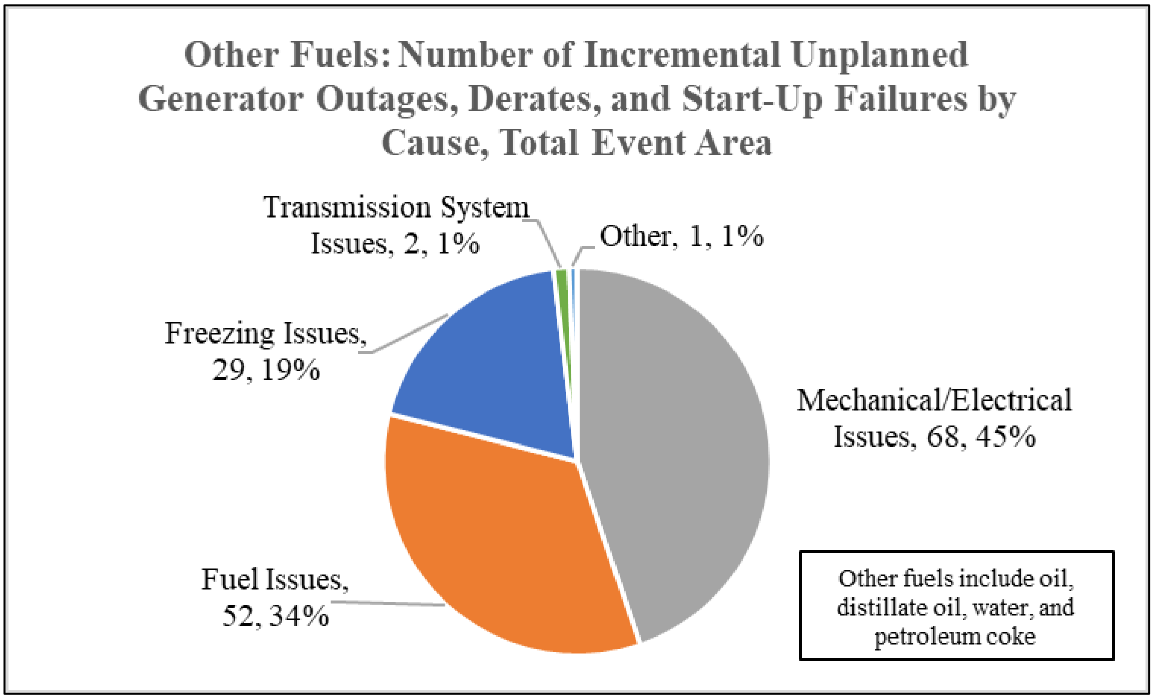
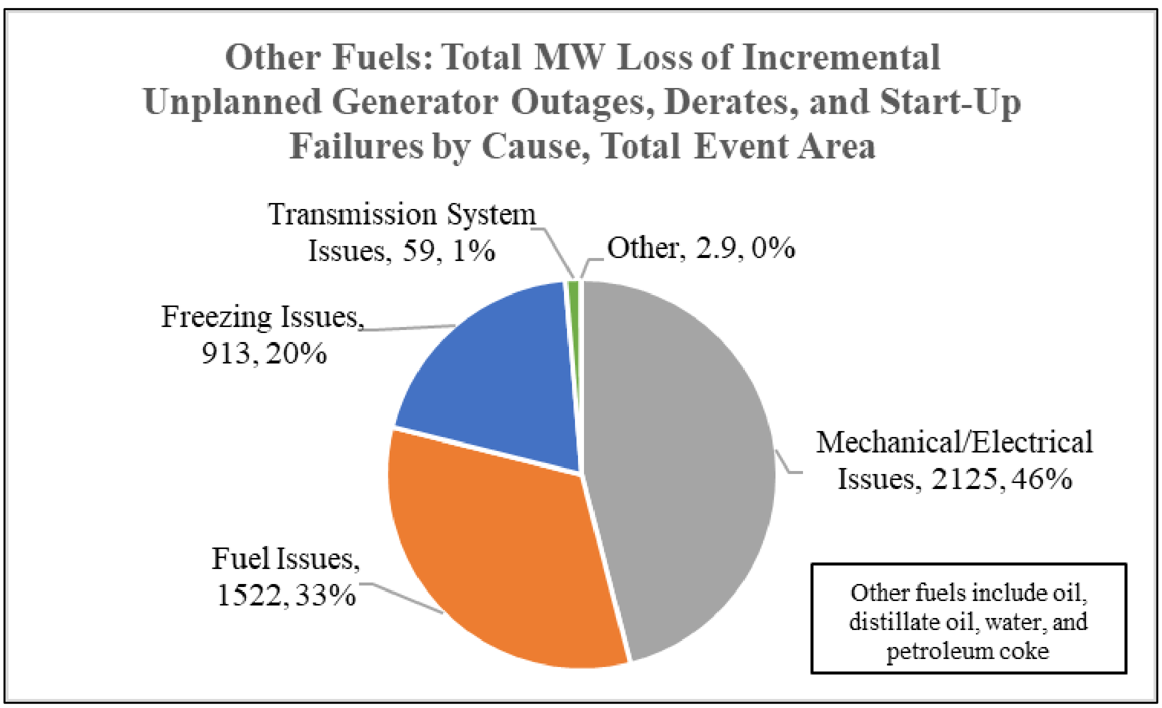


Figure 130: Causes of Unplanned Generation Outages and Derates for Other Fuel Types (by Outaged MW), Total Event Area, February 8-20



Appendix E: Interconnection Frequency Primer

Frequency Response. A key element of ERCOT's reliability performance during the 2021 cold snap was frequency response, particularly in the early morning hours of February 15. It is important to understand the severity of the frequency situation that morning, where even a relatively small loss of resources resulted in significant frequency drops in an already critical frequency situation.

Frequency Response Overview. Frequency as a measure of the reliability status of a power system can be likened to pulse or heart rate as a measure of human health. It provides a key indicator of the overall integrity of operations. Frequency control and response is the function of the "Balancing Authority." Maintaining frequency requires moment-to-moment balancing of system's aggregate generation output to its load. It also requires always having sufficient reserves available to withstand the sudden tripping of the largest generator on the system. Conversely, for loss of large amounts of load, the Balancing Authority must be able to rapidly lower generation output to reestablish the balance.

Normal Frequency Control and Response. During normal operating conditions, system frequency is maintained through the automatic generation control (AGC) system, which maintains a balance between load and resources and keeps tie line flows at prescribed levels. In ERCOT, all external tie lines are DC converter stations, so the ERCOT system operates on a frequency bias only. Several generating resources automatically raise or lower their output at the direction of the AGC system to maintain frequency. This action is called secondary frequency response (SFR) and requires frequency responsive reserves to be effective for drops in frequency.

A much faster-acting form of frequency control and response called primary frequency response (PFR) comes from automatic generator governor response, load response (typically from motors), and other devices that provide an immediate response (within seconds) to arrest and stabilize frequency in response to frequency deviations, based on local (device-level) control systems. Those actions are autonomous and are not directly controlled by the AGC system or the system operator. Again, the effectiveness of PFR is subject to the availability of headroom.

Tertiary frequency control is the next level of frequency management where a BA redispatches generation, starts more generation, or calls on demand response to restore frequency responsive reserves for PFR and SFR. This action may include manual shedding of load by the system operator to restore reserves.

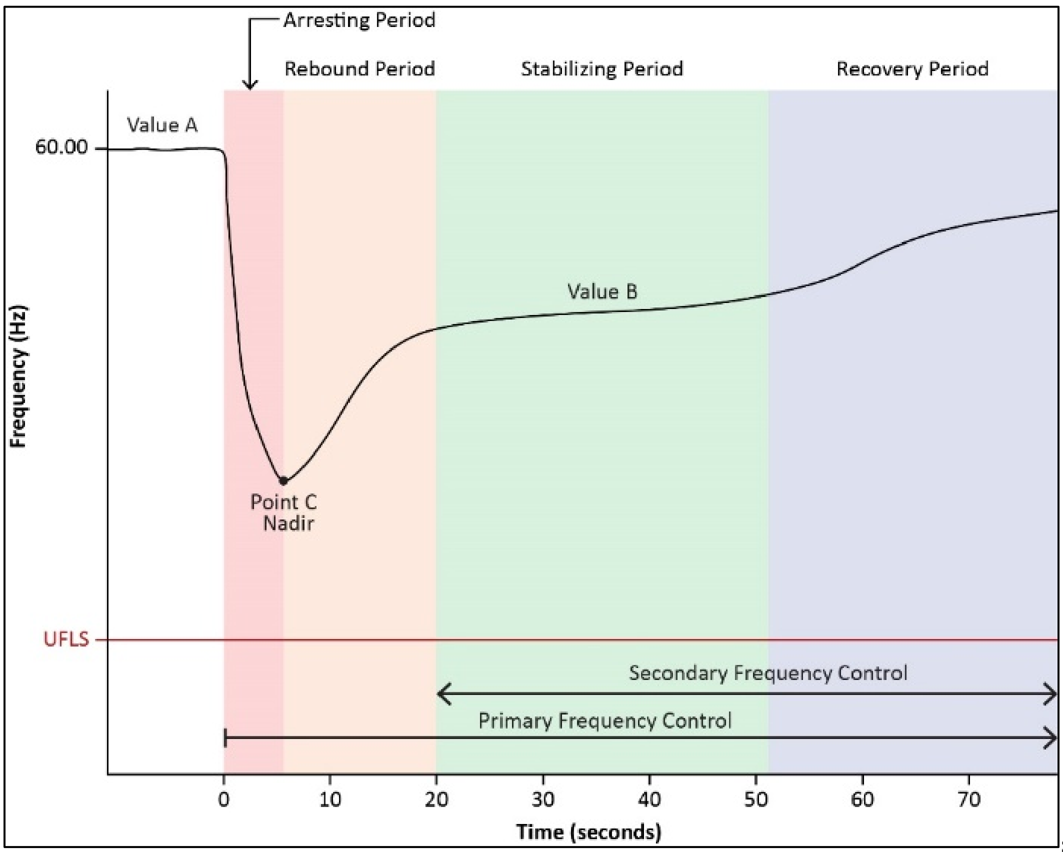
ERCOT is somewhat unique it that all generating resources in the Interconnection are subject to Regional Reliability Standard, BAL-001-TRE-2 — Primary Frequency Response in the ERCOT Region, which has been in effect since April 2015.[372] That standard requires all ERCOT resources to provide PFR for every

[372] BAL-001-TRE was implemented April 1, 2014, with compliance enforcement of the unit FRM measurements one year later in April 2015.

qualified frequency event using a frequency deadband of ±16.67 mHz.[373]. Further, the PFR performance for each generating resource is reviewed and scored for each qualifying frequency event under that standard.

New Frequency Sensitivity Metric Under Development. Both the NERC BAL-003 and ERCOT BAL-001-2-TRE standards focus of frequency response performance for significant losses of generation resources. Those standards also focus on the performance from pre-disturbance frequency Value A to the stabilized frequency Value B as defined for NERC BAL-003, as illustrated in the figure below.[374]

Figure 130: Various Stages of Interconnection Frequency Response Following Sudden Loss of Generation



Source: NERC

However, for a frequency event to be qualified for the application of those standards in ERCOT, frequency events must exceed a Value A to Point C change-in-frequency threshold of 80 mHz.

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373 Other Interconnections in North America all use a ±36 mHz deadband.

374 Pre-disturbance frequency Value A is averaged from T-16 through T+0 seconds, and the post-disturbance frequency Value B is averaged from T+20 through T+52 seconds.

A new frequency sensitivity trending metric is under development that would allow system operators to gauge how sensitive the interconnection to resource or load loss after any frequency perturbation; it works for both resource losses and load losses. It also has the benefit of not having to directly measure more complicated values like interconnection-wide inertia.

The only parameters needed are:

- Change in frequency measured in mHz,
- Time for that change to occur, and
- The amount of resource or load loss gauged in 100 MW increments.

Those measurements encompass the following indirectly

- System inertia from both rotating generation and motor loads – reflecting higher rates-of-change-of frequency for lower levels of inertia
- The dispatch mix of resources – reflecting the blend of the frequency responsiveness of the generators and other resources online – how much power and how soon can they contribute in the arresting phase of the event
- The load level reflected in the dispatch and, therefore, system inertia

Changes to Inertia and Why It Matters. As the BES transitions from conventional generators to inverter-based resources, system inertia will become lower and lower. That change will be clearly reflected in the frequency performance of the system, with a much steeper rate-of-change-of-frequency (ROCOF), indicating a lower system inertia.

By definition, inertia is the tendency for a body at rest to stay at rest, or if in motion, to stay in motion. Throughout the BES, synchronous generators are several thousand tons of mass in motion, often rotating at 3,600 revolutions per minute (at 60 Hz). The "inertial response" during a generator trip is the physics of those generators trying to maintain that 3,600 rpm speed while the system is scavenging energy from them to make up for the lost energy of the generator tripping.

The inertial tendency eventually gives way to a slowing of the rotations, dropping the system frequency until a new balance is reached, usually in less than 12 seconds. However, when inertia is lower, the fight is much quicker and the ROCOF magnitude is much higher. Since conventional generators typically begin their governor response in about 3.5 seconds, lighter inertia situations may result in a deeper and earlier nadir.

Figure 131, below shows two generating outages in ERCOT in 2009 and 2010. The red curve depicts an 890 MW generation trip at a 49,209 MW load with a relatively high inertia. The blue curve shows an 837 MW generation trip at a 23,655 MW load, with a much lower inertia. The lower inertia trip results in a ROCOF that is more than double the high inertia case.

Figure 131: Comparison of Effects on ERCOT Interconnection Frequency for Different Levels of Generator Inertia

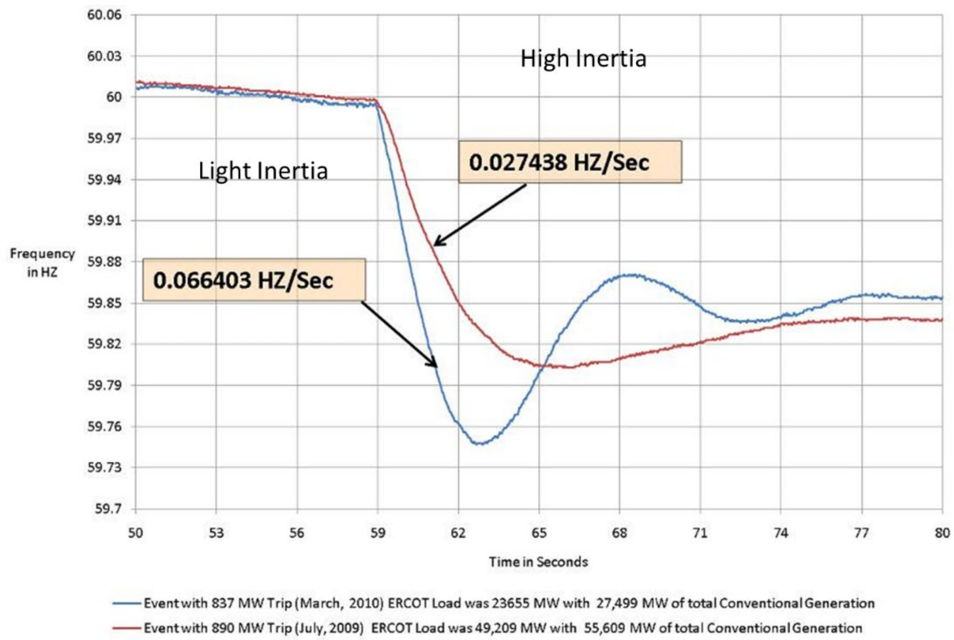
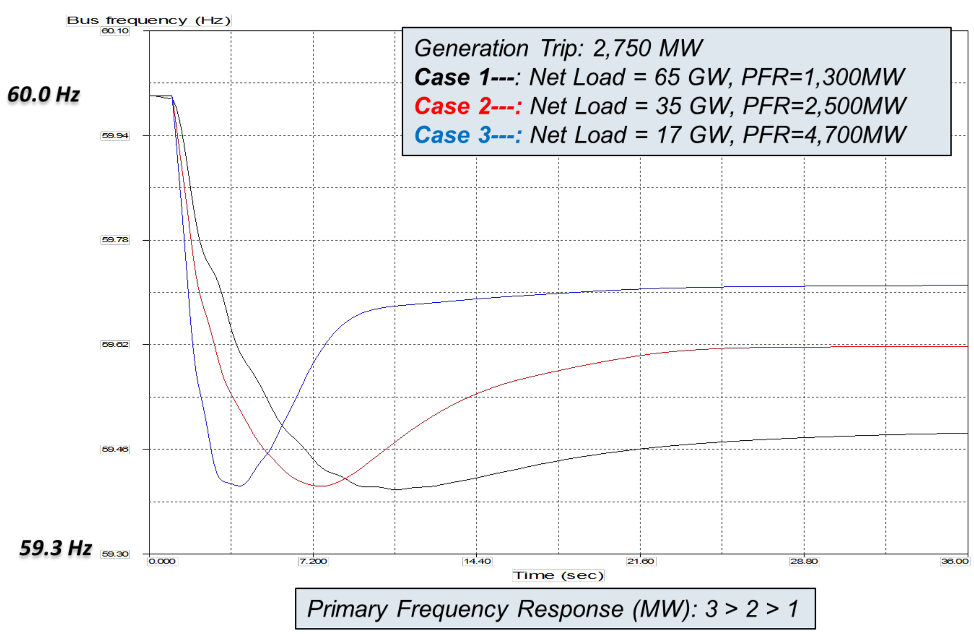


Figure 132, below shows the tradeoff between lower levels of inertia and the need for higher levels of PFR.

Figure 132: Comparison Between Lower Levels of Inertia and the Need for Higher Levels of Primary Frequency Response (PFR)



Three load/inertia cases are analyzed with PFR adjusted to maintain the frequency nadir at approximately the same frequency.[375] In all three cases, the resource loss is 2,750 MW, and the PFR is from conventional generation without any fast frequency response.

For Case 1 with the highest load and inertia, the nadir occurs at approximately 10 seconds and 1,300 MW of PFR is required for that frequency response performance.

Case 2 shows a load of 35 GW (reflecting a lower generation dispatch and inertia level). For Case 2, the ROCOF is much steeper, and the nadir occurs at about 7.2 seconds, requiring 2,500 MW of PFR for the same frequency response performance.

Case 3 shows a much lower load of 17 GW with a yet lower dispatch and inertia level. For Case 3, the ROCOF is steeper still, reflecting the lower inertia, and the nadir occurs at about 3.6 seconds. To attain the same frequency response performance as the other two cases, 4,700 MW of PFR is required.

Because lower levels of inertia require much larger PFR requirements, fast frequency response from IBRs is needed to inject energy back into the system faster during the arresting phase of the frequency event.

Frequency Sensitivity Definition – Frequency sensitivity is a rough measure of the system's trending capability to withstand losses of generation resources, calculated as the frequency change from the inflection point A to the nadir at Point C, expressed in mHz per second per 100 MW of resource loss.

EXAMPLE: If system frequency changes by -300 mHz within 15 seconds for a loss of a 1,000 MW of resource, the frequency sensitivity would be -2 mHz/second/100 MW.

In the analysis of ERCOT's frequency performance during the early morning of February 15, 2021, the Team provided frequency sensitivity for several generating unit outages to contrast how ERCOT's sensitivity to resources losses was changing.

Although this frequency sensitivity shows promise as a new metric, additional testing of its potential application is just beginning in the NERC community.

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[375] The higher the load, more generation is dispatched which includes more inertia.

Appendix F: Glossary of Terms Used in the Report

Adjacent RC - A Reliability Coordinator whose Reliability Coordinator Area is interconnected with another Reliability Coordinator Area.

Alternating Current (AC) - Electric current that changes periodically in magnitude and direction with time. In power systems, the changes follow the pattern of a sine wave having a frequency of 60 cycles per second in North America. AC is also used to refer to voltage which follows a similar sine wave pattern.

Ambient Conditions - Common, prevailing, and uncontrolled atmospheric conditions at a particular location, either indoors or out. The term is often used to describe the temperature, humidity, and airflow or wind that equipment or systems are exposed to.

Asynchronous - In AC power systems, two systems are asynchronous if they are not operating at exactly the same frequency. Two systems may also be considered asynchronous if, at potential interconnection points, there is a significant difference in phase angle between their respective voltage waveforms.

Bulk Electric System - All Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. The NERC Glossary of Terms Used in the Reliability Standards contains the list of inclusions and exclusions, and can be found at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

Capacitor - A capacitor is a device that stores an electric charge. Although there is energy associated with the stored charge, it is negligible in terms of its capability to serve load. A capacitor bank is made of up of many individual capacitors. Its purpose is to provide reactive power to the system to help support system voltage by compensating for reactive power losses incurred in the delivery of power.

Cascading - The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Constrained System Conditions - Conditions where multiple transmission facilities (lines, transformers, breakers, etc.) are approaching, are at, or are beyond their System Operating Limits.

Conductor - In physical terms, any material, usually metallic, exhibiting a low resistance to the flow of electric current. A conductor is the opposite of an insulator. In electric power systems, the term conductor generally refers to the actual wires in overhead transmission and distribution lines, underground cables, and the metallic tubing used for busses in substations. Aluminum and copper are the predominant metals used for conductors in power systems.

Contingency - The unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Contingency Reserve - Contingency reserve is the provision of capacity deployed by a Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This capacity is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment.

Curtail / Curtailment - A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

Demand - 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.

Demand Side Management - All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Derate - A reduction in a generating unit's net dependable capacity.

Direct Current (DC) - Electric current that is steady and does not change in either magnitude or direction with time. DC is also used to refer to voltage and, more generally, to smaller or special purpose power supply systems utilizing direct current either converted from AC, from a DC generator, from batteries, or from other sources such as solar cells.

Distribution Factor - The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

Emergency - Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.

Emergency Rating - The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or MVAr or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Energy Emergency – A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.

Energy Management System (EMS) - A system of computer-aided tools used by system operators to monitor, control, and optimize system performance.

Export – In electric power systems, exports refer to energy that is generated in one power system, or portion of a power system, and transmitted to, and consumed in, another.

Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Facility Rating - The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Firm Load (or Firm Demand) - That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

Firm Transmission Service/Capacity - The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.

Flowgate – 1) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

Force Majeure - A superior force, "act of God" or unexpected and disruptive event, which may serve to relieve a party from a contract or obligation.

Forced Outage – 1) The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2) The condition in which the equipment is unavailable due to unanticipated failure.

Generation – The process of producing electrical energy from other sources of energy such as coal, natural gas, uranium, hydro power, wind, etc. More generally, generation can also refer to the amount of electric power produced, usually expressed in kilowatts (kW) or megawatts (MW) and/or the amount of electric energy produced, expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator - Generally, a rotating electromagnetic machine used to convert mechanical power to electrical power. The large synchronous generators common in electric power systems also serve the function of voltage support and voltage regulation by supplying or withdrawing reactive power from the transmission system, as needed.

Grid - An electrical transmission and/or distribution network. Broadly, an entire interconnection.

Heat Tracing – The application of a heat source to pipes, lines, and other equipment which, in order to function properly, must be kept from freezing. Heat tracing typically takes the form of a heating element running parallel with and in direct contact with piping.

Hour Ending - Data measured on a Clock Hour basis.

Import – In electric power systems, imports refer to energy that is transmitted to, and consumed in one power system, which is generated in another power system, or portion of another power system.

Independent System Operator (ISO) - An organization responsible for the reliable operation of the power grid in a particular region and for providing open access transmission access to all market participants on a nondiscriminatory basis.

Interchange - Electrical energy transfers that cross Balancing Authority boundaries.

Interchange Distribution Calculator (IDC) - The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Interchange Schedule - An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.

Interconnection – A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Interconnection Reliability Operating Limit - A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.

Interruptible Load - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Load - See Demand (Electric).

Load-serving – Serves the electrical demand and energy requirements of its end-use customers.

Load Shed – The reduction of electrical system load or demand by interrupting the load flow to major customers and/or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations. In cases of capacity shortages, load shedding is often performed on a rotating basis, systematically and in a predetermined sequence.

Market Flow - The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.

Most Severe Single Contingency (MSSC) - The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Near-Term – The time period that covers the next day to multiple days ahead of the operating day.

Operating Plan - A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process - A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. It consists of spinning and non-spinning reserve.

Outage – The period during which a generating unit, transmission line, or other facility is out of service. Outages are typically categorized as forced, due to unanticipated problems that render a facility unable to perform its function and/or pose a risk to personnel or to the system, or scheduled / planned for the sake of maintenance, repairs, or upgrades.

Peak Load (or Peak Demand) – 1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.

Post-Contingency - The resulting power system conditions (determined by computer simulation, or by actual real-time data) following the unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Power - In physics, power is defined as the rate at which energy is expended to do work. In the electric power industry, power is measured in watts (W), kilowatts (1 kW = 1,000 watts), megawatts (1 MW = 1 million watts), or gigawatts (1 GW = 1 billion watts). For reference, 1 kW = 1.342 horsepower (hp).

Power System - The collective name given to the elements of the electrical system. The power system includes the generation, transmission, distribution, substations, etc. The term power system may refer to one section of a large interconnected system or to the entire interconnected system.

Power Transfer Distribution Factor - In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100 percent) of the change in power transfer.

Rating - The operational limits of a transmission system element under a set of specified conditions. In power systems, equipment and facility power-handling ratings are usually expressed either in megawatts (MW) or in mega-volt-amperes (MVA). The term is also sometimes used to describe the output capability of generators.

Reactive Power – The portion of electricity that establishes and sustains the electric and magnetic fields of AC equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It is also needed to make up for the reactive losses incurred when power flows through transmission facilities. Reactive power is supplied primarily by generators, capacitor banks, and the natural capacitance of overhead transmission lines and underground cables (with cables contributing much more per mile than lines). It can also be supplied by static VAR converters (SVCs) and other similar equipment utilizing power electronics, as well as by synchronous condensers. Reactive power directly influences system voltage such that supplying additional reactive power increases the voltage. It is usually expressed in kilovars (KVAr) or megavars (MVAr), and is also known as "imaginary power."

Real-Time – Bulk Electric System conditions, characteristics and/or data representing what actually occurred at specific times or timeframes during the Event.

Real-Time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Real-Time Contingency Analysis (RTCA) – A computer application which evaluates system conditions using real-time data to assess potential (post-contingency) operating conditions.

Regional Entity - An independent, regional entity having delegated authority from NERC to propose and enforce Reliability Standards and to otherwise promote the effective and efficient administration of bulk-power system reliability.

Regional Transmission Organization (RTO) - A voluntary organization of electric Transmission Owners, transmission users and other entities approved by FERC to efficiently coordinate electric transmission planning (and expansion), operation, and use on a regional (and interregional) basis. Operation of transmission facilities by the RTO must be performed on a non-discriminatory basis.

Reliability Coordinator Area - The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in real-time.

Stability – The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.

State Estimator – A computer application which evaluates system conditions using real-time data to assess existing operating conditions.

Transformer - A type of electrical equipment in the power system that operates on electromagnetic principles to increase (step up) or decrease (step down) voltage.

Transmission – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Line – A system of structures, wires, insulators, and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.

Trip - This refers to the automatic disconnection of a generator or transmission line by its circuit breakers.

Voltage - The force characteristic of a separation of charge that causes electric current to flow. The symbol is "V" and units are volts or kilovolts (kV).

Wide Area - The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

Appendix G: Acronyms Used in the Report

AC	Alternating Current
BA	Balancing Authority
BES	Bulk Electric System
CST	Central Standard Time
DC	Direct Current
DSM	Demand-Side Management
EEA	Energy Emergency Alert
EHV	Extra-High Voltage
EMS	Energy Management System
EOP	Emergency Operations Procedure
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FRAC	Forward Reliability Assessment Commitment
GO	Generator Owner
GOP	Generator Operator
HVDC	High Voltage Direct Current
IROL	Interconnection Operating Reliability Limit
ISO	Independent System Operator
kV	Kilovolt
LBA	Local Balancing Authority

LMR	Load Modifying Resources
MSSC	Most Severe Single Contingency
MISO	Midcontinent Independent System Operator, Inc.
MRO	Midwest Reliability Organization
MVA	Megavolt-Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
OPA	Operational Planning Analysis
PC	Planning Coordinator
PRC	Physical Responsive Capability
RC	Reliability Coordinator
RCIS	Reliability Coordinator Information System
RDT	Regional Directional Transfer
RDTL	Regional Directional Transfer Limit
RF	ReliabilityFirst Corporation
RTCA	Real-Time Contingency Analysis
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SCRD	Security Constrained Redispatch
SERC	SERC Corporation
SeRC	Southeastern Reliability Coordinator
SOL	System Operating Limit

SPP	Southwest Power Pool, Inc.
TDU	Transmission Dependent Utility
TLR	Transmission Loading Relief
TO	Transmission Owner
TOP	Transmission Operator
TP	Transmission Planner
TRE	Texas Regional Entity
TVA	Tennessee Valley Authority
UDS	Unit Dispatch System
VSA	Voltage Stability Analysis
WECC	Western Electricity Coordinating Council

Appendix H: Table of Other Recommendations about the Event

Category Electric	Recommendation
PLANNING AND RESERVES/ Reserves Recommendations, Load Forecasting, Seasonal Studies Recommendations	• Demand forecasts for severe winter storms were too low (UT Report at 8, applies to ERCOT only) • Weather forecasts failed to appreciate the severity of the storm. Weather models were unable to accurately forecast the timing (within one to two days) and severity of extreme cold weather, including that from a polar vortex. (UT Report at 8, applies to ERCOT only) • Planned generator outages were high, but not much higher than assumed in planning scenarios. Total planned outage capacity was about 4,930 MW, or about 900 MW higher than in ERCOT's "Forecasted Season Peak Load" scenario. (UT Report at 8, applies to ERCOT only) • Perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix. (SPP Report at 11, Tier 1, Assessment) • Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives9 that ensure sufficient resources will be available during normal and extreme conditions. (SPP Report at 11, Tier 1, Policies) • Develop policies that facilitate transmission expansion needed to improve SPP's ability to more effectively utilize the transmission system during severe events. (SPP Report at 13, Tier 2, Policies) • Develop transmission planning policies that improve input data, assumptions or analysis techniques needed to better account for severe events. (SPP Report at 13, Tier 2, Policies) • 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. (MISO Report, at 47) • MISO will evaluate how to incorporate existing extreme cases into Seasonal Assessments and drills (MISO Report at 48). • MISO will include the impacts of high wheel through flows in the seasonal transmission assessment to better prepare for extreme weather events. (MISO Report at 49) • 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). (MISO Report at 50) • 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. (MISO Report at 50-51) • ERCOT should improve demand forecasting capabilities. ERCOT, its market monitor, and the PUCT should all be scrutinizing ERCOT's past load forecasting and net load tools in much greater detail and sophistication. They need to identify significant biases and flaws in ERCOT's load forecasting tools and data, identify and implement better forecast tools, methods and data, and conduct on-going reassessment and improvement to assure on-going forecast accuracy with limited bias or error over time. (Recommendation 4-1, Mitchell Report) • ERCOT should broaden its use of scenario analysis with more aggressive worst-case outcomes. ERCOT should design and explore multiple climate change and extreme weather forecasts and demand scenarios in combination with multiple compound failures per event, for planning,

	resource adequacy assessments, and stress-test analyses. ERCOT's extreme stress scenarios should factor in potential communications and cyber-security failures as well as compound losses of transmission and/or generation. (Recommendation 4-2, Mitchel Report) • Acknowledge changing extreme weather threats. The Texas Legislature should require the PUCT, RRC and utilities to use forward-looking 30-year climate and extreme weather projections in combination with the worst past extreme weather and grid disaster events over a 50-year history in all planning scenarios and electricity asset reasonableness and prudence evaluations. (Recommendation 4-3, Mitchell Report) • Evaluate whether ERCOT needs different winter versus summer planning, operations and protocols. The PUCT and ERCOT should examine the distinctions between summer and winter resource needs carefully to determine whether different market products (e.g., winter-focused ancillary services) or operational protocols (e.g., limits on maintenance scheduling) are appropriate to different seasons. (Recommendation 5-1, Mitchel Report) • Greater range of extreme weather events in seasonal analysis (ERCOT Presentation, page 58) • Increase requirements for DG to provide data for planning and ops (ERCOT Presentation, page 58) • Assessment of uncertainties is critical for adequate and efficient commitment and real-time operational response (Addressed through Operations of the Future) (MISO Presentation April 27, 2021, at page 7) • Resource adequacy evaluation in constrained areas is necessary (Addressed through Market Redefinition: Resource Adequacy) (MISO Presentation April 27, 2021, at page 7) • Dispatchable Generation AND Wholesale Pricing Procedures. Provides that a generation facility is considered to be non-dispatchable if the facility's output is controlled primarily by forces outside of human control. PUCT requirements to ensure that ERCOT: Establishes reliability requirements to meet the needs of ERCOT.

	Determines the quantity and characteristics of ancillary and reliability services necessary to ensure reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production. Procures ancillary or reliability services on a competitive basis to ensure reliability during extreme conditions. Develops appropriate qualification and performance requirements for services, including appropriate penalties for failure to provide the services. Sizes the services to prevent prolonged rotating outages and to minimize load variability in high demand and low supply scenarios. • The PUCT itself must ensure: Resources are dispatchable and able to meet continuous operating requirements for the season in which the service is procured; Fuel Requirements: Winter resource capability qualifications include on-site fuel storage, dual-fuel capability, or fuel supply arrangements to ensure winter performance for several days; Summer resource capability qualifications include facilities or procedures to ensure operation under drought conditions. (Texas SB3, Sec. 18) Note, this Section has another part under market development)
COORDINATION WITH GENERATOR OWNERS/OPERATORS	• 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 Report at 48). • 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. (MISO Report at 49).

	• 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. (MISO Report at 54) • 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. (MISO Report at 54)
WINTERIZATION/ Generator Cold Weather Reliability ***Plant Design*** ***Maintenance/inspections generally*** ***Specific Freeze Protection Maintenance Items*** *(*Heat Tracing, Thermal Insulation, *Use of Wind breaks/enclosures, Training, Other Generator Owner/Operator Actions, Transmission Facilities)*	• All types of generation technologies failed. All types of power plants were impacted by the winter storm. (UT Report at 8, applies to ERCOT only) • Power plants listed a wide variety of reasons for going offline throughout the event. Some power generators were inadequately weatherized; they reported a level of winter preparedness that turned out to be inadequate to the actual conditions experienced. The outage, or derating, of several power plants occurred at temperatures above their stated minimum temperature ratings. (UT Report at 9, applies to ERCOT only) • 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 Report at 48) • MISO will focus more attention on extreme outcomes as well as expected outcomes during seasonal assessment workshops. (MISO Report at 48). • MISO will seek additional feedback from stakeholders on their learnings from past events during the Seasonal Assessment workshops. (MISO Report at 49) • 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. (MISO Report at 49-50)

	• Reassess requirements and compensation for black-start capacity and test and drill twice/year. ERCOT and the PUCT must reassess black-start performance requirements, compensation, and penalties. ERCOT must stress-test its assumptions and generators' claims about black-start unit availability and conduct regular drills to be sure that they can rebuild the system quickly after some future grid collapse, using whatever black-start resources are available. The benefits of this readiness go beyond weather-caused events to encompass preparation for and mitigation of impacts from cyber and physical attacks on the power system. (Recommendation 5-2, Mitchell Report) • Establish active reliability compliance oversight Texas. The PUCT needs trusted, competent external entities to review and verify compliance with all weatherization and reliability requirements placed upon electric generators and utilities. Additionally, ERCOT and the PUCT need to actively review and act upon reliability review findings. Compliance with weatherization and reliability mandates is essential to move the likelihood of future supply-caused power outages toward zero. (Recommendation 6-3, Mitchell Report) • Availability is less than expected when conditions are tight, and the significant drivers (e.g., winterization, fuel assurance) are unique to seasons (Addressed through Market Redefinition: Resource Adequacy Construct and Accreditation) (MISO Presentation, April 27, 2021, at page 7) • Weather Emergency Preparedness. This section applies only to municipally owned utilities, electric cooperatives, power generation companies, or exempt wholesale generators that sell electric energy at wholesale ERCOT. Requires that ERCOT prioritize inspections based on risk level. Requires PUCT to promulgate rule for inspection by independent person when an electric generation service provider experiences repeated or major weather-related forced interruptions of service. Authorizes PUCT to require an electric generation service provider to implement appropriate recommendations included in an assessment. Requires ERCOT to review, coordinate, and approve or deny requests for planned outages. (Texas SB3, Section 13)

	• Texas PUCT Preparedness Reports. The PUCT is required to analyze emergency operations plans developed by electric utilities, power generation company, municipally owned utilities, and electric cooperatives that operate generation facilities and retail electric providers and must provide a report on preparedness. If the PUCT finds an operator's plan inadequate, the PUCT i*s required* to have the operator file an updated emergency operations plan. (Note: the PUCT was formerly "authorized" to require an updated plan). The PUCT must report its preparedness findings to the Lieutenant Governor, Speaker of the House and certain members of the legislature in every even-numbered year. (Texas, SB3, Section 24) • Sec. 25 – Railroad Commission Weather Emergency Preparedness Reports. Requires the RRC to analyze emergency operations plans developed by those natural gas facilities operators and are included on the electricity supply chain map. The RRC must prepare a preparedness report on weatherization preparedness of facilities included on the electricity supply chain map is If the RRC finds the emergency operations plans to be inadequate, it must require the operator to upgrade its emergency operations plans. The results of the RRC analysis must reported to the Lieutenant Governor, speaker of House, and certain members of the legislature. (Texas, SB3, Section 25)
COMMUNICATIONS/ RC-to-RC Communication, Situational Awareness, Seams Issues	• Develop or enhance the tools, communications and processes identified by the ORWG and needed to improve SPP and stakeholder response to extreme conditions, such as: o Enhance real-time cascading analysis studies and post results. o Develop tool(s) to increase operator awareness of Out of Merit o Energy (OOME) instructions. o Enhance and expand the use of R-Comm.10 o Create a reliability dashboard to improve situational awareness for operators. o Utilize member-maintained distribution lists for communications purposes.

	- Develop a process to update operations management during extreme conditions. (SPP Report at 12, Tier 2, Action) - Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance and fairly compensate emergency energy. (SPP Report at 13, Tier 2, Action) - Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: - Processes that ensure stakeholders have a dependable way to receive timely, accurate and relevant information regarding emergencies. - Plans to drill emergency communications procedures with all relevant stakeholders. - Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers, and government entities and stay up-to-date. ((SPP Report at 14, Tier 2, Action) - Evaluate and propose needed enhancements to communications tools and channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc. (SPP Report at 14, Tier 2, Assessment) - Form a stakeholder group whose scope would include discussion of matters related to emergency communications. (SPP Report at 14, Tier 3, Action) - To increase public awareness of and satisfaction with SPP, develop materials intended to educate general audiences on foundational electric utility industry concepts and SPP's role in ensuring electric reliability. (SPP Report at 14, Tier 3, Action) - 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. (MISO Report, at 47) • Transfer capability - MISO will examine load pockets as part of transmission planning and resource accreditation. (MISO Report, at 47) • 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. (MISO Report, at 47) • 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. (MISO Report at 51) • When MISO requests a Regional Dispatch Transfer (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. (MISO Report at 51) • 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. (MISO Report at 51) • 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. (MISO Report at 51) • Design tools to provide better visualization of the system and its pain points. (MISO Report at 52) • 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. (MISO Report at 52) • MISO will continue to leverage collaboration tools to allow newer Operations staff to observe during real-world emergency events. (MISO Report at 52)

	• Proactively assess internal, regulator, and stakeholder data needs to identify sources for the data and standardize the format for delivering the data. (MISO Report at 54) • 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. (MISO Report at 54) • 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 Report at 54) • Study the potential benefits and costs of adding additional high-voltage transmission between ERCOT and its neighboring interconnections. ERCOT is unique among Although additional transmission lines would not have been able to bring in enough additional energy to fill the deep shortfall ERCOT experienced on the morning of February 15, 2021, they could help to prevent or ameliorate future grid operational problems, particularly black-start energy that could be invaluable to rebuild the grid in the event of a future collapse. Last, given Texas' wealth of wind, solar and natural gas resources, the state could benefit from exporting generation. These issues and opportunities should be studied in a thorough and apolitical fashion. An independent expert committee studied the question of transmission integration (called alternative current interconnection) with the Eastern Interconnection in 1995-6 pursuant to a 1995 Legislative directive. That study concluded that the costs exceeded the benefits of such interconnection. The new SB1 budget authorization directs the PUCT to again study the costs and benefits of interconnection with the Eastern and Western Interconnections and with Mexico. Such a study can address the questions above. (Recommendation 6-4, Mitchell Report) • Improve completeness and timeliness of resource outage reporting (ERCOT Presentation, page 58)

LOAD SHEDDING/ Transmission Operations and Reserves, System Operating Limits Recommendations	• Grid conditions deteriorated rapidly early in February 15 leading to blackouts. So much power plant capacity was lost relative to the record electricity demand that ERCOT was forced to shed load to avoid a catastrophic failure. (UT Report at 8, applies to ERCOT only)
	• Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations. (SPP Report at 12, Tier 2, Assessments)
	• Implement improvements to load-shed processes to be developed by the Operating Reliability Working Group (ORWG), such as:
	  o Utilize real-time load values when determining load-shed ratio shares.
	  o Train and drill on multiple overlapping load-shed instructions.
	  o Perform a detailed review of models used to determine load shed ratio shares.
	  o Develop and document procedures and processes to address the timing and responsibility of curtailing exports before and during a load-shed event. (SPP Report at 12, Tier 2, Action)
	• Develop a policy to ensure TOP emergency response and load-shed plans have been reviewed, updated, and tested on an annual basis to verify their effectiveness, with attention to critical infrastructure. (SPP Report at 12, Tier 2, Policy)
	• 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 Report at 48)
	• Require Texas TDUs to modify distribution circuits for more granular outage management. The PUCT should order utilities to modify their distribution systems using sectionalization devices wherever feasible to cut up each

	circuit into smaller sections, starting on those circuits hosting critical facilities so that a single hospital doesn't lock in service for a giant chunk of a city and leave others literally out in the cold. (Recommendation 3-1, Mitchell Report) • Texas should require large industrial and commercial customers to be able to reduce load remotely. Require large industrial and commercial customers, including State of Texas facilities, to have the capability to reduce load remotely by at least 30% under emergency circumstances, and require these facilities to cut their loads before ERCOT orders residential customer load-shedding. (Recommendation 3-2, Mitchell Report) • Texas should require all critical facilities to have two days' worth of backup power. The Legislature should require most critical facilities to have two days' worth of backup power (combination of PV, battery, and low-emissions propane or diesel generation). This offers two major benefits—it will improve community resilience in the face of diverse threats (such as extreme weather disasters or cyber-attack), and it will help each critical facility and its community ride through a brief grid outage or outage management failure. (Recommendation 3-3, Mitchell Report) • Facilitating rotation of higher load shed amounts in ERCOT (ERCOT Presentation, page 58) • Improve accuracy of telemetry related to frequency-responsive capability (ERCOT Presentation, page 58) • Sufficient transfer capability within and between regions is critical to enabling the advantages of regional diversity (Addressed through Long Range Transmission Planning) (MISO Presentation, April 27, 2021 at page 7) • Information Provided by Retail Electric Provider. Requires a retail electric provider to inform retail customers of involuntary load shedding procedures. Specifies the types of customers who can be considered "critical care residential customers," "critical load industrial customers," or "critical load according to PUCT rules." (Texas SB3, Section 9) • Ancillary Services. Provides the PUCT with the authority necessary to facilitate transmission of electric energy available at reasonable prices with the terms and conditions that are not unreasonably preferential, prejudicial,

	discriminatory, predatory, or anti-competitive." Requires the PUCT to require ERCOT to modify for design, procurement, and cost allocation of ancillary services in a manner that is consistent with cost-causation principles and on a nondiscriminatory basis. (Texas SB3, Section 14) • Involuntary and Voluntary Load Shedding. Requires the PUCT to promulgate rules for load-shedding by ERCOT. Requires the PUCT to issue rules that categorize the types of critical load that may receive the highest priority for power restoration. Requires the PUCT to issue rules that these entities maintain a list of customers willing to voluntarily participate involuntary load reduction and to coordinate with municipalities, businesses, and customer that consume large amounts of electricity to encourage voluntary load reduction. Requires the PUCT and ERCOT conduct load shedding exercises during both the summer and winter. (Texas SB3, Section 16) Note this Section has another recommendation about gas production captured below. • Distributed Generation Reporting. Owner or operator of distributed generation must register with ERCOT; Owner or operator must provide interconnecting transmission and distribution utility information necessary for the interconnection of distributed generator. (Texas, SB3, Section 19)
Category Natural Gas	**Recommendation**
Natural Gas Failures	• Failures within the natural gas system exacerbated electricity problems. Natural gas production, storage, and distribution facilities failed to provide the full amount of fuel demanded by natural gas power plants. Failures included direct freezing of natural gas equipment and failing to inform their electric utilities of critical electrically-driven components. (UT Report at 9, applies to ERCOT only) • Failures within the natural gas system began prior to electrical outages. (UT Report at 9, applies to ERCOT only) • Some critical natural gas infrastructure was enrolled in ERCOT's emergency response program. (UT Report at 9, applies to ERCOT only) • Natural gas in storage was limited. (UT Report at 9, applies to ERCOT only)

Fuel Assurance	• Develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region. (SPP Report at 11, Tier 1, Policies) • Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events. (SPP Report at 11, Tier 1, Assessment) • Develop policies to improve gas-electric coordination that better inform and enable improved emergency response. (SPP Report at 11, Tier 2, Policy) • 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. (MISO Report at 48) • MISO will incorporate fuel assurance into scenario planning and drills, with a particular focus on MISO visibility into fuel plans. (MISO Report at 49) • Improved identification of critical gas facilities (ERCOT Presentation, page 58) • Mandatory weatherization to minimum standards for natural gas production and pipelines, with meaningful enforcement (Recommendation 1-1, Mitchell Report) • Creation of Texas Energy Reliability Council. This is a new organization whose function is to foster better communication between the natural gas and electric industries. It is unclear where this organization fits in relation to ERCOT and the PUCT. (Texas SB3, Section 3) • Critical Natural Gas Facilities and Entities Rules. Requires the RRC to work with the PUCT to adopt rules to establish a process to designate certain natural gas facilities and entities associated with providing natural gas in Texas as "critical customers" or "critical natural gas suppliers" during energy emergencies. (Texas SB3, Section 4) • Weather Emergency Preparedness Rules. It applies to gas supply chain facility. In general, requires the Railroad Commission of Texas (RRC) to promulgate a rule that requires a gas supply chain facility operator to implement measures that will enable the facility to operate during a weather emergency. The RRC is required to inspect gas

	supply chain facilities for compliance with rules that it issues. There are penalties associated with noncompliance (Texas SB3, Section 5, Section 6(penalties)) • Landfill Gas-to-Electricity Use. Permits non-utilities to produce, generate, transmit, distribute, store, sell or furnish electricity produced by the use of landfill methane gas. Texas SB3, Section 15) • Rules for Designating Critical Natural Gas Facilities and Entities. Requires, among other things, the PUCT to collaborate with the RRC to adopt rules that establish a process to designate certain natural gas facilities and entities that provide or otherwise associated with providing natural gas as critical during an energy emergency. Requires that ERCOT ensure that all facilities that provide electricity are given the same information under the Natural Resources Code. (Texas SB3, Section 16)
Markets	**Recommendation**
Market Design, Pricing, Credit &Settlement, and other regulatory recommendations	• Develop and improve policies to ensure price formation and incentives reflect system conditions. (SPP Report at 13, Tier 2, Policy) • Develop and implement market design and market-related enhancements identified by the Market Working Group to improve • operational effectiveness and ensure governing language provides needed flexibility and clarity, such as: ○ Improve the Dispatch Target Adjustment Process. Enhance the Multiday Reliability Assessment Process. (SPP Report at 13, Tier 2, Action) • Develop policies to ensure financial outcomes during emergency conditions are commensurate with the benefits provided. (SPP Report at 13, Tier 2, Policy) • Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in the first quarter of 2022. (SPP Report at 14, Tier 2, Assessment) • Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes. (SPP Report at 14, Tier 3, Assessment)

	• Clarify tariff language related to SPP's settlements and credit-related authorities and responsibilities. (SPP Report at 14, Tier 3, Action) • 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. (MISO Report at 51) • Investigate and evaluate the allocation of Real-Time Excess Congestion, including Revenue Neutrality Uplift costs, due to scarcity pricing. (MISO Report at 52) • 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. (MISO Report at 52) • MISO is evaluating if Tariff amendments will help MISO address these types of situations (bankruptcy, default) in the future. A potential solution is amending the Tariff to modify the notice process required to parties to resolve the conflicts recently experienced. (MISO Report at 52) • (Alternative Credit Exposure Calculations) 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 (MISO Report at 53) • (Alternative Credit Exposure Calculations) 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. (MISO Report at 53) • 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. (MISO Report at 53)

	• 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. (MISO Report at 53) • Re-evaluation of creditworthiness requirements (ERCOT Presentation, page 58) • Wholesale Pricing Procedures for Emergencies. PUCT is required to promulgate rules to establish an emergency pricing program for wholesale electric market Initiation (legislative determination): Goes into effect if the high system-wide offer cap has been in effect for 12 hours in a 24-hour period after initially reaching the high system-wide offer cap. PUCT determines criteria for ceasing emergency pricing program. PUCT implements legislative determination: must prohibit an emergency pricing program cap to exceed any nonemergency high system-wide offer cap. PUCT establishes an ancillary services cap to be in effect during the period an emergency pricing program is in effect. PUCT implements legislative determination: low system-wide offer cap cannot exceed a high system-wide offer cap. PUCT must review each system-wide offer cap program it adopts at least once every five years to determine whether to update aspects of the program. PUCT implements legislative determination: generators to be reimbursed for reasonable, verifiable operating costs that exceed the emergency cap. (Texas SB3, Sec. 18) Note, this Section has another part included above)

Regulatory	
Regulatory Recommendations	• Update Texas building energy codes and require them to be automatically updated as international building codes are updated (Recommendation 2-1, Mitchell Report) • Raise TDU energy efficiency program goals to increase both annual kWh savings and peak reduction (Recommendation 2-2, Mitchell Report) • Increase energy efficiency retrofits for low-income and multi-family housing across Texas. PUCT should require at least 40% of electric utility energy efficiency program savings to come from retrofits of low-income and multi-family housing. The Legislature should modify TDHCA's low-income programs to include weatherization, building repairs and replacement of inefficient heating and cooling appliances and systems. (Recommendation 2-3, Mitchell Report.) • Increase demand response for grid emergencies. All-electric utilities, municipal utilities, and cooperatives should offer customers compensated demand response options and procure demand response that can cut at least 10% of each entity's summer peak load and 10% of each entity's winter peak load through remote actuation. (Recommendation 2-4, Mitchell Report) • Do not add an out-of-market "generation capacity reserve" scheme. The blackouts in February were not due to the lack of generation capacity within ERCOT, but rather to the failure of many generators to prepare their hardware and fuel supplies adequately for the Arctic weather; a capacity market would not have prevented this outcome. Similarly, adding emergency capacity through a fleet of additional generators funded without regulatory scrutiny through a non-market charge or tax will raise costs to every electricity customer and chill other new or existing investors' willingness to compete in the ERCOT market. (Recommendation 5-3, Mitchell Report) • Strengthen Texas' Public Utility Commission. The Legislature should increase PUCT funding and headcount to enable the Commission to hire more expert staff and consultants and improve the ongoing education of staff and commissioners about pressing market and oversight issues. (Recommendation 6-1, Mitchell Report)

	• Give ERCOT an independent, expert Board of Directors. We recommend that future ERCOT board members be selected by ERCOT Board members without any external political screening, to avoid any actual or appearance of political interference with critical, complex Board decisions affecting the ERCOT power system. And ERCOT would be better served if the Board contains some non-Texans with valuable expertise and insight to complement and broaden the Texas perspective. (Recommendation 6-2, Mitchell Report) • Release all Texas investigative findings to the public The governor should direct all Texas entities to release all investigation findings on the February outages, with no agency withholding privileges and minimal protection of private entities' commercial information. (Recommendation 7-1, Mitchell Report) • Routinely collect data on all grid and fuel supply failures and make it public. The public deserves to understand what happened when the institutions and infrastructure we rely on fail. Policy-makers need to know why it happened in order to prevent future failures. Understanding energy infrastructure problems requires that both private and public entities and individuals who possess relevant information share it, without excessive retreat behind claims of governmental or commercial privilege. The state should create formal mechanisms and entities to identify, collect and analyze relevant grid and related information for routine and extraordinary conditions (including fuel production and delivery status, power plant and transmission line status, and distribution utility outages and critical facility lists). A few elements of emergency event information may justify protection for the sake of grid security, but we should lean toward requiring all information to be shared analysis and improvement and minimize state agency or commercial barriers against information release. (Recommendation 7-2, Mitchell Report) • Improved public communications of EEA events (ERCOT Presentation, page 58) • Requires the Department of Public Safety "with the cooperation of" the Department of Transportation, the Texas Division of Emergency Management, the governor's

	office, and the Public Utility Commission of Texas (PUCT) to develop "an alert" to be activated when there is a "power outage alert." PUCT is given the authority to adopt criteria for the content, activation, and termination of the alert. (Texas SB3, Sec. 1.) • Texas Electricity Supply Chain Security and Mapping Committee. The Committee's responsibilities include: To map the state' s electricity supply chain; To identify critical infrastructure sources in the electricity supply chain; To establish best practices to prepare facilities that provide electric and natural gas services in the electricity supply chain to maintain service in an extreme weather event and recommended oversight and compliance standards for those facilities; To designate priority service needs and to prepare for, respond to, and recover from an extreme weather event. (Texas SB3, Section 17) • Penalties - Disconnecting Residential Customer During an Emergency. A natural gas provider is prohibited from disconnecting service to a residential customer during an extreme weather emergency. Associated with penalties (Texas, SB3, Section 20) • Public Education and Awareness. The RRC must adopt rules that educate the public regarding pipelines; The RRC must adopt the rules concerning the measures that a gas pipeline facility operator is required to implement in order for the pipeline to maintain service quality and reliability during extreme weather conditions; The RRC must inspect gas pipeline facilities for compliance with rules; An owner/operator must be given a reasonable time to remedy violations. The RRC must report such person to the Attorney General if the violation is not remedied within a reasonable period of time. The RRC must issue a rule requiring a gas pipeline facility operator that experiences repeated major weather -related forced interruptions must contract with a non-employee to conduct an assessment of the operator's plans and procedures for weatherization. The assessment must be presented to the PUCT. The RRC has the authority to require an operator of a gas pipeline to implement the recommendations of the assessment. The RRC must issue a penalty against an operator if it fails to remedy a violation within a reasonable period of time. (Texas, SB3, Section 21, and 22 (penalties).

	• Sec. 33 – State Energy Plan Advisory Committee. Establishes this committee of 12 members chosen by the Governor, Lieutenant Governor, and Speaker of the House. Requires that this committee prepare "a comprehensive state energy plan" by September 2022 that will evaluate methods to improve reliability, stability and affordability of electric service and provide recommendations for removing barriers that prevent sound economic decision. Requires that it evaluate "electricity market structure and pricing mechanisms" that are used to provide electric services including ancillary services and emergency response services. (Texas SB3, Section 33)

Appendix I: Data Sources Including List of Credits for Graphics not Created by Team

Natural Gas Infrastructure Data Collection. The Natural Gas Act grants the Commission authority to regulate "transportation of natural gas in interstate commerce." The Commission ensures that the rates, terms, and conditions of service by interstate natural gas pipelines, including storage and liquid natural gas (LNG) facilities, are just and reasonable and not unduly discriminatory. In addition, the Commission certificates construction and operation of interstate natural gas pipelines, including storage and LNG facilities, upon a finding of public convenience and necessity. The Commission does not have jurisdiction over much of the intrastate pipeline system, and has no jurisdiction over natural gas production, gathering, or processing.

The team asked non-jurisdictional natural gas infrastructure entities to voluntarily provide data, and thanks the many entities that did cooperate with the inquiry. Findings and recommendations for the natural gas industry are based on the following data collection, unless a data source is otherwise identified:

- Pipelines: the team obtained data from entities representing 62 percent of the total interstate pipeline mileage in Texas, 63 percent in Oklahoma, 53 percent in Kansas, and 40 percent in Louisiana. The data also includes approximately 86 percent of the total intrastate transmission mileage in the state of Texas and 22 percent in Louisiana. The team submitted data requests to pipelines based on the size of their footprint in Texas, Oklahoma, Kansas, and/or Louisiana and those most often mentioned as the source of natural gas for generators who were unable to operate due to natural gas supply issues.
- Processing: The team obtained data from processing entities owning approximately one-eighth of the total processing facilities in the affected region. In an attempt to get a representative cross-section, entities were chosen based on factors including size of individual facilities (large, medium, and small); whether the owner/operator is also involved in other parts of the industry supply chain (i.e. they also own gathering systems, pipelines, etc.); the number of facilities each entity owns or operates within Texas, Oklahoma, and Louisiana; the proportion of the region's overall processing capacity the entity holds; and whether one or more of the entity's facilities experienced an outage during the Event. The data obtained represented 15.5 percent (4.4 Bcf/d) of 2017 Texas processing capacity, 27.1 percent (1.6 Bcf/d) of 2017 Oklahoma processing capacity, and less than 1 percent (0.001 Bcf/d) of 2017 Louisiana processing capacity. Many of the recommendations stem from themes common across numerous data responses, giving the team a higher degree of confidence that the experiences of the processing facilities from which we collected data were not outliers.
- Production: Many natural gas producers are small, and they are numerous. Even some of the largest producers in Texas individually account for only approximately 8 percent of the total production. *See* https://stage.rrc.state.tx.us/oil-gas/research-and-statistics/operator-information/top-32-texas-oil-gas-producers/ "Top 32 Texas Oil & Gas Producers" for 2019, available at https://stage.rrc.state.tx.us/media/60870/top32producers2019.pdf. Given the infeasibility of obtaining data from thousands of producers, the team selected entities representative of various sizes of production by volume, as well as to cover the impacted basins in Texas, Oklahoma, and Louisiana. 22.3 percent (4.69 Bcf/d) of average Texas production volumes, 31.9 percent (1.86 Bcf/d) of average Oklahoma production volumes and 16.6 percent (1.31 Bcf/d) of

average Louisiana production volumes, based on EIA monthly production volumes. Some of the producers that provided data also owned gathering facilities, but the team did not attempt to separate gathering facilities from their associated natural gas system components.

List of Credits for Graphics not Created by Team:

- Figure 53: Natural Gas Demand November 2020 – February 2021
  - Credit: S&P Global Platts
- Figure 54: South Central U.S. Natural Gas Inflows and Outflows, February 1 – 20, 2021
  - Credit: Texas Oil and Gas Association
- Figure 55: Texas Natural Gas Inflows and Outflows, February 1 – 20, 2021
  - Credit: Texas Oil and Gas Association
- Figure 56: Texas Natural Gas Flow Changes to Neighboring Regions
  - Credit: S&P Global Platts
- Figure 62: Natural Gas Storage Withdrawals and Injections
  - Credit: UT Report, Figure 2w (attributed to Wood Mackenzie)
- Figure 108: Air-Source Residential Heat Pump Hourly Electric Demand Versus Outdoor Temperature, with Auxiliary Heating Demand
  - Credit: Philip White et al., Quantifying the impact of residential space heating electrification on the Texas electric grid, 298 Applied Energy 1, 1-11 (2021).

Appendix J: Primer on Electric Markets and Reliable Operation of the BES

To help ensure that the electric grid operates as reliably and efficiently as possible, Congress granted FERC jurisdiction over electric grid reliability through the enactment of the Energy Policy Act of 2005 (EPAct), by adding a new section to the Federal Power Act, 16 U.S.C. § 215. Pursuant to its EPAct authority, FERC certified the North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization (ERO) responsible for establishing mandatory Reliability Standards, which then must be approved by FERC. FERC also promulgated regulations, approved Regional Entities to serve as regional compliance authorities,[376] and approved over 100 NERC-proposed mandatory Reliability Standards. This oversight over the grid's reliability by FERC and NERC is vital to assuring consistent and dependable access to electricity. NERC currently has 14 Reliability Coordinators (RC) in North America to ensure that the grid is run efficiently and reliably. These RCs cover wide areas, and have the operating tools and processes to do so, including the authority to prevent or mitigate emergency operating situations. Electric Reliability Council of Texas, Inc. (ERCOT), Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) all served as RCs in the Event Area. ERCOT, MISO and SPP are also Independent System Operators, and MISO and SPP are Regional Transmission Organizations (RTOs).[377] In the United States, RTOs and ISOs (hereafter, we will use ISO/RTOs to refer to both) plan, operate and administer wholesale markets for electricity. These entities, which are regulated by FERC, manage markets for energy and related services, for specific regions of the country.

Ensuring reliable operation of the power grid is complex and requires constant analysis and assessment. This is true for two fundamental reasons: (1) it is difficult to economically store large quantities of electricity, so electricity must be produced the moment it is needed; and (2) because alternating current (AC) electricity flows freely along all available transmission paths through the path of least resistance, it must be constantly monitored to maintain electricity flows over transmission lines and voltages within appropriate limits. The power system therefore must be operated so that it is prepared for conditions that could occur, but have not happened yet.[378] Should an outage or reliability issue occur, system operators must act promptly to mitigate

[376] The Regional Entities relevant to this event are Midwest Reliability Organization, ReliabilityFirst, SERC Reliability Corporation, and Texas Regional Entity.

[377] *See* Figure 1 in the body of the report for a map of the Event Area. ERCOT manages a wholesale energy market which is not regulated by FERC, since the exchange of power between entities occur wholly within the state not through interstate commerce.

[378] NERC's mandatory Reliability Standards require that the bulk-power system be operated so that it generally remains in reliable condition, without instability, uncontrolled separation, or cascading, even with the occurrence of any single contingency, such as the loss of a generator, transformer, or transmission line. This is commonly referred to as the "N-1 criterion." N-1 contingency planning allows entities to identify potential N-1 contingencies before they occur and to adopt mitigating measures, as necessary, to prevent instability, uncontrolled separation, or cascading. As FERC stated in Order No. 693 with regard to contingency planning, "a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system. Such an approach is necessary to ensure that planning will produce results that will enhance the reliability of that system. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance." *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1716 (2007), *order on reh'g*, *Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

adverse conditions and remain within appropriate limits. For conditions severe enough that they could cause instability, uncontrolled separation or cascading outages, mitigation must occur within no more than 30 minutes. Equally vital to the continued operation of the grid is that it is restored to a condition where it can once again withstand the next-worst single contingency.

All of the ISO/RTOs operate both "day-ahead" and a "real-time" energy markets. In the day-ahead market, buyers and sellers schedule electricity production and consumption before the operating day, which produces a financially-binding schedule, the day-ahead generation resource unit commitment, for electricity production and consumption one day prior to the actual generation and use. This provides generators and electricity load-serving entities a forecast of their needs prior to the day's operations and enables system operators to prepare an Operating Plan Analysis for the next day.[379] To perform the day-ahead unit commitment, ISO/RTOs operators look for the most economic generators to schedule to be online for each hour of the following day, taking into account factors such as a unit's minimum and maximum output levels, how quickly those levels can be adjusted and whether the unit has minimum time it must run once started, as well as operating costs. Operators need to take into account forecast electricity demand or load conditions for every hour of the next day, and other factors that could affect grid capabilities such as expected generation and transmission facility outages, any adverse weather conditions (e.g. severe heat or cold, precipitation, high winds), and line capacities. If the analysis suggests that optimal economic dispatch cannot be carried out reliably, more expensive generators may need to replace the cheaper generators to operate reliably.

The current operating day, or real-time market, begins with the Operating Plan Analysis, created with generators who bid into and were chosen in the day-ahead market. It then reconciles any differences between the day-ahead schedule and the real-time load, while taking into account real-time conditions such as forced or unplanned generation and transmission outages, as well as electricity flow limits on transmission lines and other criteria, such as voltage, for BES reliability.

Categories of NERC Registered Entities who Operate the BES

NERC identifies functions for which the entities responsible for operating the BES in a reliable manner can register with NERC. These registrations then guide which of the mandatory Reliability Standards the entity must follow. A single entity can conduct multiple reliability functions and therefore have multiple NERC registrations. The NERC registrations most relevant to this event are Reliability Coordinator, Balancing Authority, Generator Owner and Generator Operator, Transmission Operator and Planning Coordinator.

The RC is the highest level of authority and maintains reliability for its entire footprint. The RC is expected to have a "wide-area" view of its entire footprint, beyond what any single Transmission Operator could observe, to ensure operation within Interconnection Reliability Operating Limits (IROLs).[380] It oversees

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[379] *See* Appendix K, "System Operator's Tools and Actions to Operate the BES in Real Time."

[380] An IROL is a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System. *See* NERC Glossary of Terms at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure reliable operation of the BES. The RC, for example, may direct a TOP to take whatever action is necessary to ensure that IROLs are not exceeded. The RC performs reliability analyses including next-day planning and Real-Time Contingency Analysis (RTCA) for its footprint, but these studies are not intended to substitute for TOPs' studies of their own areas. Other responsibilities of the RC include responding to requests from TOPs to assist in mitigating equipment overloads. The RC also coordinates with TOPs on system restoration plans, contingency plans, and reliability-related services.

The RC is responsible for overseeing transmission operations for the wide area of the interconnection that it oversees. Similar to the TOP, below, the RC ensures the reliable real-time operation of transmission assets by performing operational planning analyses (OPAs) and preparing Operating Plans, but the RC has the "wide-area" view, beyond any individual TOP within an RC footprint. In coordination with other RCs, the RC maintains situational awareness beyond its own boundaries, to enable it to operate within its Interconnection Reliability Operating Limits (IROLs), which are limits necessary to prevent system instability and cascading outages, and it maintains reliability of its RC area. Like the BA, below, the RC ensures the generation-demand balance is maintained, but within the larger RC Area, thereby ensuring that the Interconnection frequency remains within acceptable limits. The RCs for the Event Area include ERCOT, SPP, and MISO.

The BA integrates resource plans ahead of time, contributes to the interconnection[381] frequency in real time, and maintains the balance of electricity resources (generation and interchange) and electricity demand or load within the BA Area. The BAs for the event include ERCOT, SPP and MISO. Within the MISO footprint, local BAs (LBAs) perform a small number of functions, for which they are jointly registered with the MISO BA to perform.

The GO owns and maintains generating facilities. **The GOP** operates generating unit(s) and performs the functions of supplying energy and interconnected operations services required to support reliable system operations, such as providing regulation and reserve capacity, and sharing data with BAs and TOPs as required. Many GO and GOP entities are registered as both GOs and GOPs.

The TO owns and maintains transmission facilities. **The TOP** ensures the real-time operating reliability of the transmission assets within its area. It has the authority to take actions to ensure the continued reliable operation of the Transmission Operator Area. Like the RC, it performs daily OPAs and prepares Operating Plans, but for its smaller TOP footprint. The TOP coordinates with neighboring BAs and TOPs, as well as

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[381] An interconnection is a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec (*See* NERC Glossary of Terms at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf). The ability to transfer power between two interconnections is limited by the capability of the direct current (DC) tie-lines between them, as well as the limitations of components that exist within in each interconnection.

RCs, for reliable operations. The TOP also develops contingency plans, operates within established System Operating Limits, and monitors operations of the transmission facilities within its area.

The PC is responsible for coordinating and integrating transmission facility and service plans, resource plans, and protection systems, and **the TP** is responsible for developing a long-term (generally one year and beyond) plan for the reliability of the interconnected bulk transmission systems within its portion of the Planning Coordinator Area.

Key Concepts related to Reliable Operation of the Bulk Power System

- **Voltage Control** – Maintaining consistent voltage levels is imperative, as wide deviations in the voltage levels can have severe consequences. Voltage below certain limits could lead to an electric system imbalance or collapse. Voltages above certain limits can exceed insulation capabilities and lead to equipment damage and outages. Winter peak electricity loads include resistive loads such as resistive heating, which has a higher load power factor than during summer peak conditions. Load power factor is an indicator of reactive demand —the higher the load power factor, the lower the reactive power demand. A relatively small percentage change in power factor, such as a change from 88 percent summer peak load power factor, to a 92 percent winter peak load power factor, can result in 30 percent less need for reactive power to be supplied during the winter. Summer peak electricity load includes air conditioning, which, like other induction motors, has lower power factors and consumes more reactive power than winter loads. Even with more stable voltages during winter peak conditions, system operators must continually monitor and evaluate system conditions, examining reactive reserves and voltages, and adjust the system as necessary for secure operation. [382]
- **Power Flow/Stability Control** – Protection systems (e.g. relays) are implemented and configured to guard against the unplanned loss of a generator or line from resulting in instability. Additionally, power (or angle) stability limits are set to ensure that unplanned losses will not cause the remaining generators or lines to lose synchronism (or operate out of step) with each other, causing equipment damage.
- **Operations Planning** – Operations planning time horizon includes day-ahead, week-ahead, seasonal, and up to one-year planning horizons. The primary focus of operations planning is operational readiness and preparedness to assure availability of existing generation resources and transmission facilities to reliability operate the BES. Operations planning differs from short- and long-term planning horizons. Those focus on one- to ten-year planning horizons and include evaluations to plan for adequate generation resources and transmission capacity to ensure the system will be able to withstand severe contingencies in the future without widespread, cascading outages.
- **Coordination and Communication Between Entities** – the Reliability Standards encourage principal entities (e.g., Reliability Coordinators, Balancing Authorities, Transmission Operators,

[382] U.S.-Canada Power System Outage Task Force "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" (April 2004) at 26.

Generator Operators, and Distribution Providers) to communicate effectively in real-time to maintain system balance between generation and load, stay within operating limits, and address issues that arise.

Ultimately, the RCs, BAs, TOPs, and other responsible entities must work individually and together to comply with the mandatory Reliability Standards and to ensure the continued reliable operation of the bulk power system.

Appendix K: System Operator's Tools and Actions to Operate the BES in Real Time

Monitoring of the transmission grid. RCs and TOPs employ system operators and engineers who use various methods to forecast and evaluate upcoming and real-time issues, so as to avoid or mitigate problems that arise in their electric grids. They continually monitor transmission facilities 24 hours a day, seven days a week, for situational awareness of the power grid. System operators typically have available a variety of real-time computer tools for monitoring the system, including State Estimator (SE) and Real-Time Contingency Analysis (RTCA).[383] RC system operators are constantly monitoring RTCA and RTCA-based displays, including lists of facilities that exceed System Operating Limits or have voltages deviating from voltage criteria in real time, and lists of facilities that would exceed System Operating Limits or have voltages deviating from voltage criteria if a contingency were to occur (another system element, such as a line, transformer or generating unit, is outaged) (the latter list is called post-contingency exceedances).

Respecting transmission system limits. For both real-time and post-contingency limit exceedances, the system operators have a number of step-wise mitigating actions they can take to restore the facilities to within system limits or voltages to within voltage criteria. For simulated post-contingency exceedances, some operator actions are taken before the contingency occurs, while for other post-contingency exceedances, the operator relies on mitigation to be taken only if the contingency were to occur. Operators should only rely on post-contingency mitigation if they are confident that there would be sufficient time to complete the mitigation before adverse system conditions (such as instability or cascading outages) would occur.

The mere fact that an actual or real-time system operating limit is exceeded does not necessarily mean that immediate reduction below the limit is required, although it does require immediate operator action. As an example, RC operators may contact Transmission Owners to determine if a temporarily-higher rating is warranted. For a projected next- or post-contingency System Operating Limit (SOL) exceedance, if also projected to exceed an Interconnection Reliability Operating Limit (IROL), meaning that it could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the BES, RC operators have a maximum of 30 minutes to take actions alleviate the IROL exceedance.[384] Otherwise, for SOLs, operators identify mitigation measures they could take as part of their operating plan, which may include measures that would be implemented prior to, or if the next contingency occurred.

[383] SE constructs a representation of the state of the system using voltages, currents, and breaker status from the real-time data, and calculates values for which data are not directly collected; while RTCA runs frequently, for example, every two to six minutes for MISO and SPP, and informs the operators how the system would be affected for the computer-simulated outage or in other words used interchangeably, "for loss of" (FLO) a specific system facility such as a transmission line or a transformer.
[384] This time is defined as the "Interconnection Reliability Operating Limit T_v" which is the maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.

Monitoring power transfers to avoid exceeding transmission limits. To aid in monitoring and regulating power flows across the transmission system (often referred to as managing transmission "congestion"), system operators in RTO areas define "flowgates," by pairing specific transmission facilities and their associated next contingencies that would compound the transmission facility loading if the associated next contingency occurred. In addition to RTCA, RC operators in the Eastern Interconnection possess computer-based flowgate monitoring tools, which use the shared interchange distribution calculator (IDC) to calculate percentages of power flow impacts that each interchange power transfer schedule has on each flowgate; i.e., its transfer distribution factor, or TDF. For instance, if the need arises to reduce flowgate loading to remain within system operating limits, or in other words, alleviate market "congestion", the flowgate monitoring tool enables the operators to determine the appropriate megawatt power flow amount that can be reduced in the external market transfer to achieve this goal.

Security-constrained economic dispatch. To manage the grid, the ISO/RTO takes a wide-area view of all the resources available to it, resulting in a "dispatch stack" that contains generators from all generation-owning members of the region, including utility and non-utility Generator Owners, as well as some generation resources outside the footprint. A security constrained economic dispatch (SCED) algorithm is used to determine the appropriate and least-cost generating units to dispatch at any given time depending on market conditions. SCED aids the RTOs by, among other tasks, simultaneously balancing energy injections and withdrawals, managing congestion, and ensuring adequate operating reserves. The SCED process runs every five minutes to establish dispatch instructions for generators to meet the future load of the next five-minute period. The purpose of the algorithm is to minimize the cost to meet the forecast demand, scheduled interchange, and reserve requirements while also being subject to transmission congestion and other system reliability constraints.

An initial approach to relieving transmission congestion constraints in RCs which are also RTOs is redispatching generation at different locations on the grid, done through SCED. When system operating limits are reached, i.e., when constraints reach a threshold at which other resources will soon need to be dispatched, market operators/RCs proactively enter constraints into SCED to begin preparation for unanticipated system events. When system operators change the day-ahead generation dispatch schedule to accommodate constraints or unexpected transmission or generation outages, it is known as "security constrained redispatch."

Generation redispatch. If non-cost measures do not alleviate the congestion concerns, operators should utilize least-cost redispatch measures, including initiating market-to-market (M2M) redispatch procedures for reciprocally coordinated flowgates (RCFs) between RTOs, or utilizing a transmission loading relief procedure (TLR), which prioritizes the various types of transmission services, allowing system operators to cut less-firm transportation flows first.

Some RTOs that share a "seam," or common border, including MISO and SPP, utilize the M2M coordination process between the RTOs to assist in maintaining efficient, reliable service for their respective regions. The M2M process allows for both RTOs' RCs to coordinate interface pricing by modeling the same constraint. The previously-defined RCFs are monitored closely to gauge the impact of market flows and parallel flows from adjacent regions and markets. MISO and SPP can utilize M2M upon constraint activation in the market. During the course of the Event, MISO and SPP's RC System Operators were in frequent communication with each other, analyzing congestion and engaging in M2M congestion management when necessary to relieve congestion on binding constraints.

Transmission loading relief. In the Eastern Interconnection, RC operators can issue one or more TLR(s) to curtail transmission flowgate loadings due to power transfers on an hour-by-hour basis. TLRs are used to ration transmission capacity when demand for the transmission is greater than the available capacity. TLRs are typically utilized when the transmission system is overloaded to the point where power flows must be reduced in order to protect the system. The rationing is done based upon a priority structure that lowers or limits the power flows based on size, contractual terms, and scheduling, as opposed to the redispatch of lowest cost generation in M2M. [385] This method can be used in MISO and SPP at the RC's discretion.

Emergency measures. If a situation worsens, for example where operators have exhausted use of their tools to alleviate constrained conditions on the BES and an emergency condition is identified, the NERC Reliability Standards require specific actions in the event of an emergency. Reliability Standard EOP-011-1 requires BAs and TOPs to have plans to mitigate operating emergencies in their respective areas. Plans are required to include provisions for operator-controlled manual load shedding that minimizes the overlap with automatic load shedding and are capable of being implemented in a timeframe adequate for mitigating the emergency.

Energy emergencies. For energy emergencies, where there are not sufficient generation resource reserves for system electricity demands within a BA area (or stranded resource reserves exist - not deliverable meet electricity demands within a sub-area of a BA), an energy emergency alert (EEA) is declared. To ensure that all RCs clearly understand potential and actual energy emergencies in the Interconnection, NERC established three levels of EEAs. The RCs use these terms when communicating energy emergencies to each other. An EEA is an emergency procedure, *not* a daily operating practice. The RC may declare whatever alert level is necessary, and need not proceed through the alerts sequentially. The following is a list of the EEA levels and their description:

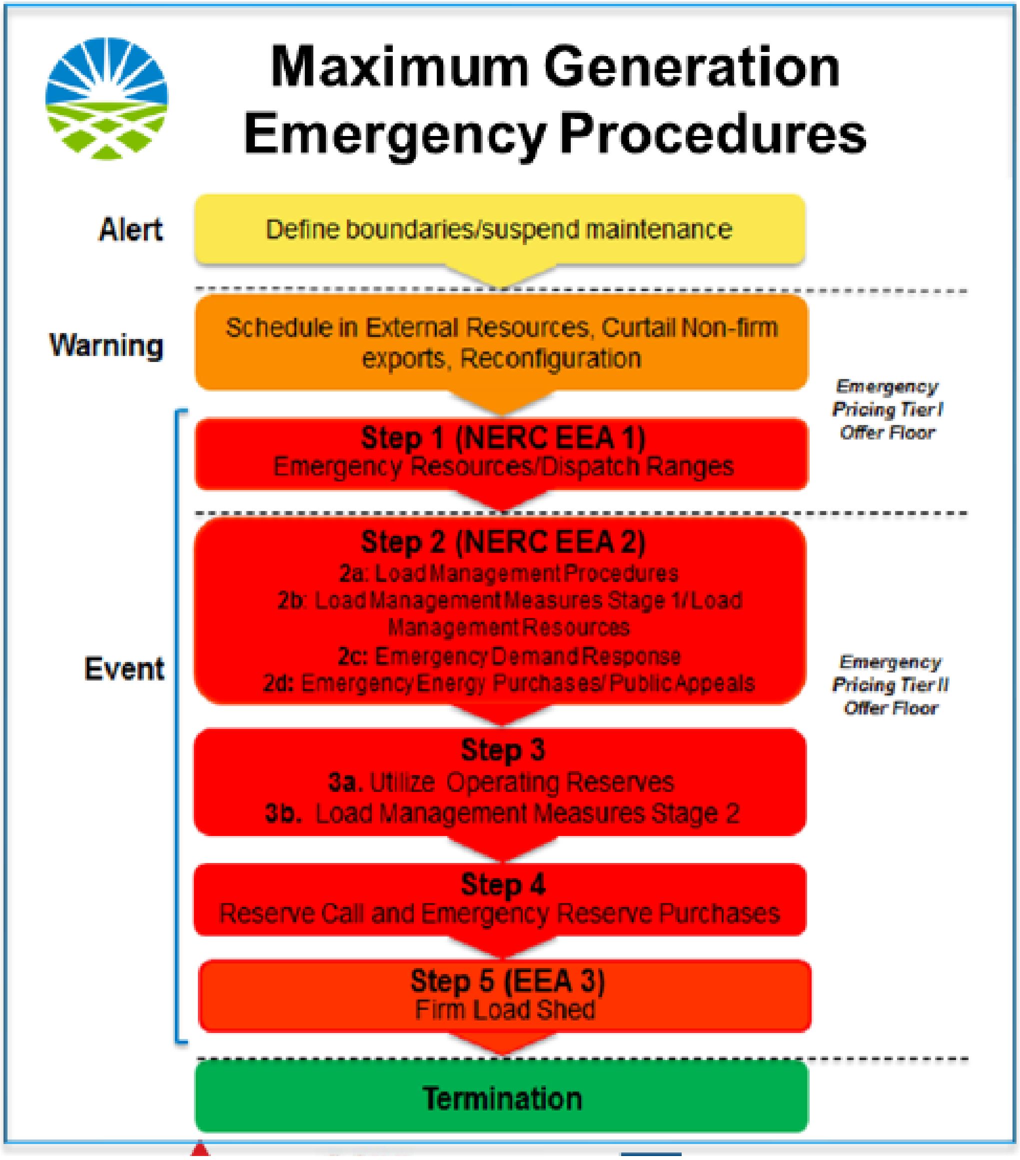
EEA 1 — All available generation resources in use.

EEA 2 — Load management procedures in effect.

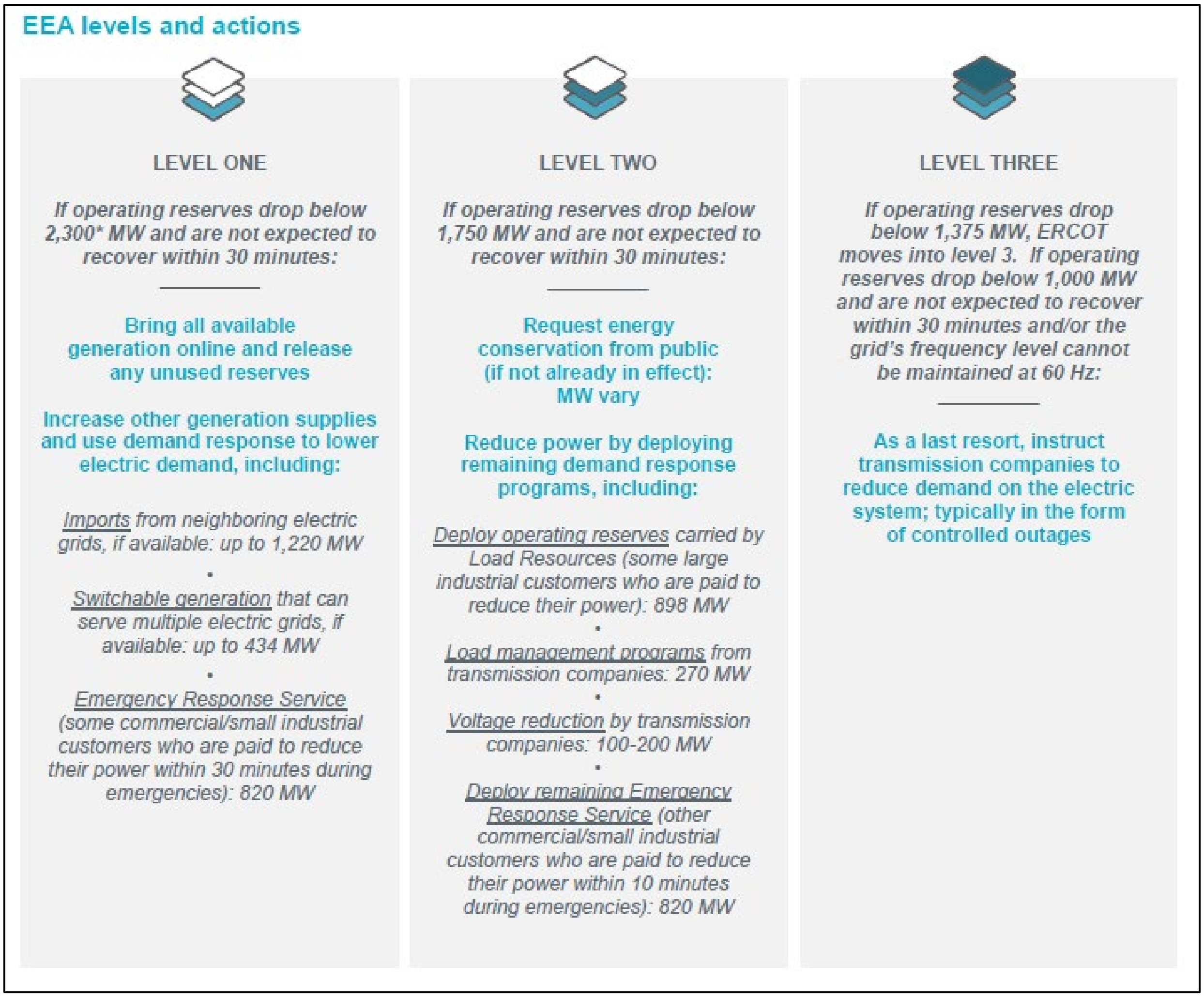
EEA 3 —Firm Load interruption is imminent or in progress.

ERCOT's, MISO's and SPP's procedures are required to be in accordance with these levels. Their procedures may contain specific steps for operators to take within these levels. For example, MISO's procedures include the following steps:

[385] The NERC TLR Procedure is an Eastern Interconnection-wide process that allows Reliability Coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. *See* https://www.nerc.com/pa/rrm/TLR/Pages/default.aspx



ERCOT's energy emergency actions in accordance with the EEA levels are shown in the following illustration:



<u>Transmission emergencies</u>. TOPs may identify BES constrained conditions as being a transmission emergency, where the issue is *not* insufficient resource reserves within a BA footprint, but rather transmission system operating limits have been reached or exceeded and emergency measures are needed to alleviate the condition, such as operator-controlled manual load shedding in a specific location that effectively alleviates the transmission overload condition. TOPs are required to notify its RC when experiencing the emergency.

Appendix L: Primer on Natural Gas Production, Processing, Transportation and Storage

Natural gas production is not comprehensively regulated, and no government agency monitors daily production activity. However, some aspects of production are subject to regulation; gas-producing states monitor well drilling and permitting, and in Texas, for instance, the Railroad Commission has jurisdiction over oil and gas wells located in the state and over persons owning or engaged in drilling oil and gas wells located in the state.[386] Congress deregulated the price on natural gas at the wellhead.[387] FERC does not regulate natural gas producers, and retail natural gas sales to consumers are regulated by state public utility commissions, not by FERC.

FERC's jurisdiction over the transportation of natural gas under the Natural Gas Act (NGA) or the Natural Gas Policy Act of 1978 (NGPA),[388] which also includes the provision of natural gas storage services, begins when the gas is delivered to an interstate pipeline and continues until the gas is delivered to the wholesale purchaser, absent some intervening transaction which renders the activity exempt from federal jurisdiction. While generally the activities of intrastate pipelines and local distribution companies are exempt from FERC jurisdiction, when those entities engage in the transportation of natural gas in interstate commerce or wholesale sales for resale of natural gas, their activities are subject to FERC jurisdiction.

FERC's responsibilities include:

- Issuance of certificates of public convenience and necessity to construct and operate interstate pipeline and storage facilities, and oversight of the construction and operation of pipeline facilities at U.S. points of entry for the import or export of natural gas.
- Regulation of transportation and sales for resale in interstate commerce that are not first sales.
- Regulation of the transportation of natural gas.
- Regulation of liquefied natural gas facility siting.
- Establishment of rates and terms and conditions for jurisdictional services.[389]

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[386] Among the matters covered by the Texas Railroad Commission regulations are space and density of drilling; prevention of waste; approval of water flood permits; location exceptions; intrastate pipelines; environmental and safety aspects of production, including well plugging; regulation of the injection of carbon dioxide into reservoirs; and maintenance of well records including logs, maps and production reporting. Jack M. Wilhelm, Texas Land Institute, *What Every Landman Should Know about the Railroad Commission of Texas* (2005), available at http://blumtexas.tripod.com/sitebuildercontent/sitebuilderfiles/wilhelm.pdf.
[387] Natural Gas Wellhead Decontrol Act, Pub L. No. 101-60, 103 Stat. 157 (1989).
[388] FERC also has NGA jurisdiction over sales for resale of natural gas that are not deemed first sales. A first sale does not include the sale by an interstate pipeline, intrastate pipeline, or LDC, or affiliate thereof, unless such sale is attributable to volumes of their own production.

[389] The North American Energy Standards Board (NAESB) provides business standards for pipelines in areas such as the scheduling of pipeline transportation.

- Pipelines then publish FERC-approved tariffs that cover to services, terms and conditions and rates for gas transportation.

Most interstate pipelines no longer offer sales services. The two broad categories of transportation service on an interstate pipeline are firm and interruptible transportation, subject to specified exceptions such as force majeure clauses. (The interstate pipeline companies sell transportation, not the gas itself, which is almost always is purchased separately from the producer by the shipper, except for some intrastate pipelines that sell both.) Shippers obtain firm transportation by reserving capacity with a pipeline. Shippers customarily pay a charge for the reservation of guaranteed capacity rights on the pipeline and a separate usage charge; pipeline firm rates thus include cost recovery of pipeline facilities in addition to recovery of variable transportation costs such as fuel. Interruptible service rates are usage charges that are derived from the firm service rates. Interruptible shippers do not reserve any capacity, and the pipeline will only provide service to an interruptible shipper the extent it is available.[390]

Prior to the deregulation of wellhead gas prices and open access transportation established under Commission Order No. 436 in 1985 and Order No. 636 in 1992, producers typically sold gas to both intrastate and interstate pipelines; these entities in turn sold the gas to LDCs that delivered the gas to end users. With the issuance in 1992 of Order No. 636, the Commission required interstate pipelines to unbundle their services to separate the transportation of gas from the sale of gas. Thus, today most interstate pipelines do not engage in the buying and selling of natural gas except for operational purposes. Order No. 636 further required interstate pipelines to set up informational postings to show available pipeline capacity and to ensure that all participants have access to available capacity. Additionally, holders of the firm capacity can, through capacity release, resell those rights on a temporary or permanent basis.

To understand the effects that rippled throughout the natural gas and electric systems as a result of the severe cold weather, it helps to understand a bit about the infrastructure itself. Natural gas production begins at the many thousands of wellheads located throughout the basins. The wellhead consists of equipment on top of the well that is used to manage flows of oil and gas, often produced together, arising from the underground formations. The high-pressure gas in formations is lighter than air and will often rise on its own through the wellhead to surface pipes. In other gas wells, as well as oil wells with associated natural gas, flow requires lifting equipment. Typical lifting equipment consists of the “horse head” or conventional beam pump. The pumps are recognizable by the distinctive shape of the cable feeding fixture, which resembles a horse's head and is often called a “pumpjack.” The following two photographs are of a pumpjack and a wellhead, respectively. As the photo shows, the wellhead equipment above ground typically is uncovered and uninsulated, leaving the liquids in it vulnerable to freezing.

[390] Pipeline Knowledge and Development, The Interstate Natural Gas Transmission System: Scale, Physical Complexity and Business Model (August 2010), available at www.ingaa.org/File.aspx?id=10751.

Wells and lift equipment are monitored on a daily basis and maintained by oil and gas company employees, who are often referred to as "pumpers" or "gaugers." Their responsibilities include reporting malfunctions and spills, and ensuring that field processing equipment is operational and that production is correctly measured. Onshore gaugers may drive many miles per day to monitor dozens of wells and are dependent on the roads remaining passable.

The natural gas used by consumers consists almost entirely of methane. However, produced gas often contains other hydrocarbons such as water vapor, hydrogen sulfide, carbon dioxide, helium, nitrogen, and other compounds. Some field processing occurs near production wells to remove the water and condensates, but complete processing usually occurs at gas processing facilities. Natural gas processing facilities remove other hydrocarbons to produce what is known as "pipeline quality" dry natural gas that meets the heating content and other restrictions necessary for the safe operation of pipeline and distribution company facilities. The removed hydrocarbon natural gas liquids are sold separately.[391] Natural gas is transported to processing facilities[392] typically through small diameter and low-pressure gathering pipelines.

After gathering and processing, interstate and intrastate transmission pipelines transport gas to local distribution companies (as well as to directly attached users such as generating units). Within the United States, the pipeline network delivers gas to 76.9 million residential, commercial, industrial, and power generation customers.[393] It includes at least 210 gas pipeline systems with a total of more than 301,955 miles of transmission pipelines.[394] The pipeline system also includes more than 1,400 compressor stations, 1,000 delivery points, 5,000 receipt points, and 1,400 interconnection points.

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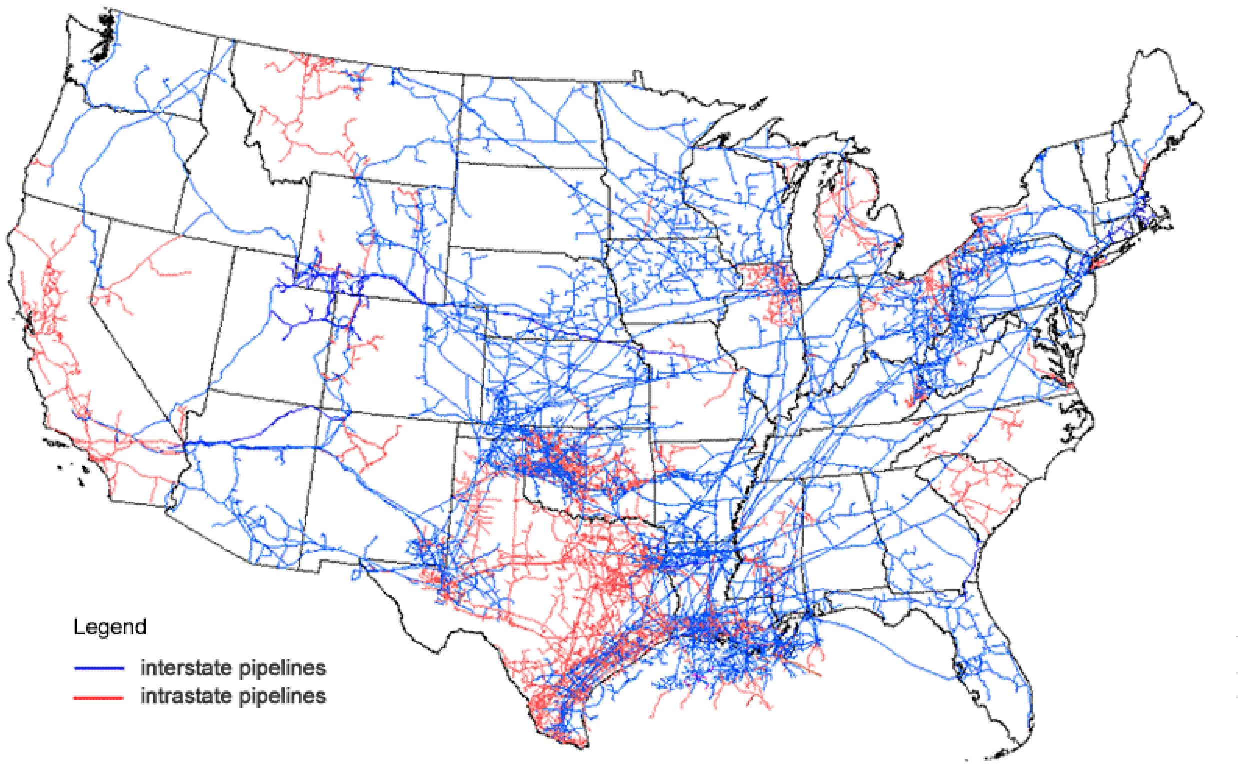
391 2011 Report at 34, *see also* https://oilandgasproductionhandbook.blogspot.com/2014/01/reservoir-and-wellheads.html
392 510 processing plants operated in the Lower 48 States in 2017 with 183, or 36 percent, in the state of Texas. EIA, *Natural Gas Processing Capacity in the Lower 48 States*, (Feb. 1, 2019), https://www.eia.gov/analysis/naturalgas
393 https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php *Last updated: December 3, 2020.*
394 https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems *Last updated: September 1, 2021.*

Figure 133: Map of U.S. Interstate and Intrastate Natural Gas Pipelines



Source: U.S. Energy Information Administration, *About U.S. Natural Gas Pipelines*

Pipeline companies monitor and control gas flow with computerized supervisory control and data acquisition (SCADA) systems, which provide operating status, volume, pressure, and temperature information. In addition to real-time monitoring, the SCADA system may enable a pipeline to start and stop some facilities remotely.

To meet higher gas demand at various times of the year, gas is stored underground in depleted oil and gas reservoirs, aquifers or caverns formed in salt beds. Storage facilities may be interstate and regulated by FERC, or intrastate and non-jurisdictional. There are over 387 active underground storage fields in the Lower 48 states, of which approximately 196 are under FERC jurisdiction. Depleted oil and gas reservoirs account for 87 percent of the total FERC jurisdictional storage capacity, with salt caverns (3 percent) and aquifers (10 percent) accounting for the rest.[395]

[395] https://www.ferc.gov/industries-data/natural-gas/overview/natural-gas-storage/natural-gas-storage-storage-fields *Last updated: July 22, 2020.*

Appendix M: Sensing Lines and Transmitters

There were many reports of frozen transmitters causing generating units to be forced offline during the cold weather event. In almost all cases, it was not the transmitters themselves that froze, but rather sensing lines filled with standing (non-flowing) water routed between the transmitters and the points the sensing lines are measuring.

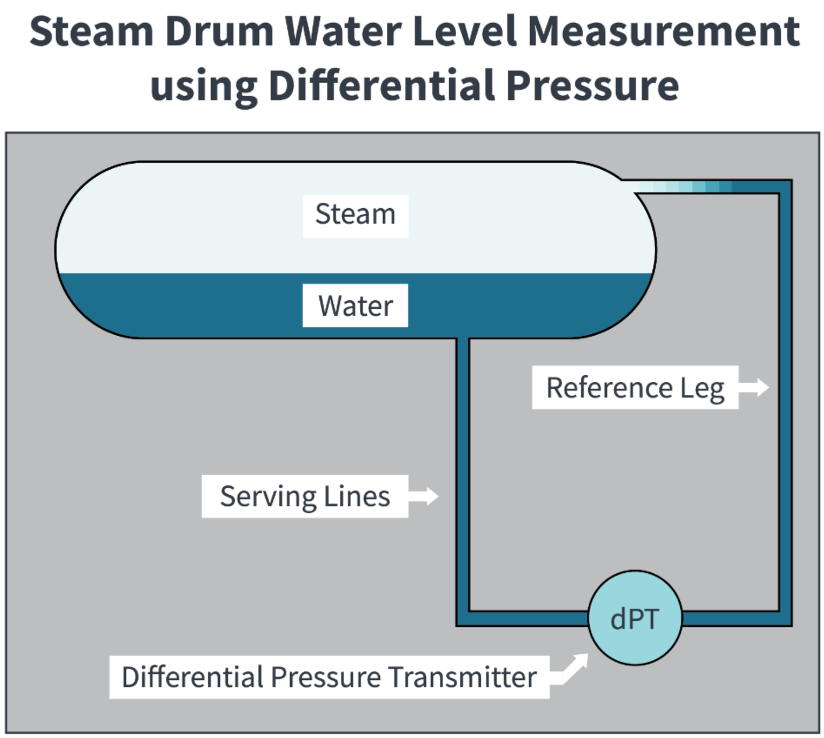
Transmitters. The transmitter assemblies perform three distinct functions. First, they detect the difference in pressure between two water lines, typically with a diaphragm-type sensor that deflects in the direction of, or towards, the lower pressure. Second, they serve as transducers that translate the pressure difference into an electrical signal. Third, they boost or otherwise process the signal for transmitting to the plant's control room, generally using electronics.

Differential Pressure Measurement. The technique of measuring the pressure difference (differential pressure) between two sensing lines filled with water has widespread application throughout power plants, especially in steam-powered generating units. Differential pressure can be used to provide not just a measure of pressure itself, but also of water levels and flow rates. Significant applications include the following:

- **Pressure Measurement**
  - Between a boiler feedwater pump and the steam drum
- **Water Level Measurement**
  - In feedwater heater tanks
  - In the deaerator tank
  - In the steam drum
- **Water Flow Measurement**
  - Feedwater flow
  - Generator stator cooling water flow

Water Level Measurement. Differential pressure can be used to measure water level by virtue of the force of gravity, which results in greater pressure as the water level increases. This is akin to the hydraulic head resulting from water in an open reservoir, which is a measure of water pressure compared against standard atmospheric pressure. The method needs to be modified, however, to account for the fact that the space within a tank above the water is pressurized. Hence the use of differential pressure measurement, with one sensing line connected to the bottom of the tank to sense the water pressure, and the other to the top of the tank to sense the water vapor or steam pressure. The line at the top of the tank is known as the reference line. Even though the reference line connects to the top of the tank, which is above the water level, it will itself still fill up with water because the vapor/steam condenses in the line due to the much cooler ambient air temperature external to the tank.

Figure 134: Steam Drum Water Level Measurement using Differential Pressure



<u>Water Flow Measurement.</u> Differential pressure can be used to measure water flow by virtue of Bernoulli's principle: an increase in the speed of a flowing fluid is accompanied by a decrease in pressure. This increase in speed can be forced by placing a constriction such as an orifice plate or nozzle inside a pipeline, reducing its effective diameter. In order for the rate of flow in gallons per minute, for example, to remain the same, the velocity of the fluid must increase to make up for the fact that it is travelling through a smaller opening. This phenomenon is known as the Venturi effect. The higher velocity translates into lower pressure by Bernoulli's principle. Thus, measuring the differential pressure on either side of the constriction provides a measure of the rate of flow through the pipeline.

For exact flow measurement, the design and dimensions of the constriction are critical. In some cases, however, the concern lies more with changes in flow rate, indicative of blockages in the piping or overall flow path. This concern is important when strainers are used to filter out undesired particles from the fluid, especially in generator stator cooling systems. The strainers provide constriction to the water flow, resulting in a pressure difference. When the strainers are clogged, the pressure difference increases.

Steam flow can also be measured using the Venturi effect. But in that case, long sensing lines are not needed, as pressure immediately on either side of the orifice plate or nozzle is measured.

<u>The Freezing Problem.</u> Since differential pressure measurement requires gauging the difference in pressure between two separate sensing lines, if the water in either or both of those lines freezes, the measurement will be false. When a sensing line is plugged with ice, it cannot convey the intended water pressure to the transmitter location.

The fact that the water in the sensing lines is not flowing makes freezing all the more likely and emphasizes the need for proper freeze protection methods such as insulation and heat tracing. Some sensing lines must run long distances through areas exposed to outdoor ambient air, which significantly exacerbates the risk of false readings.

November 2021

FERC - NERC - Regional Entity Staff Report:

The February 2021 Cold Weather Outages in Texas and the South Central United States

Federal Energy Regulatory Commission

North American Electric Reliability Corporation

Regional Entities

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR CPS 1 (A, B, C) – ENERGY MARKET REDESIGN

CPS Energy and the City of San Antonio should join with other cities, municipal utilities, and rural electric cooperatives to develop and propose legislation in the 2023 legislative session to accomplish the following:

1.A: require all generators and marketers on the ERCOT grid to maintain a prescribed level of reserve capacity from base load plants, dispatchable plants or energy storage facilities with direct ownership of generation capacity or firm contractual agreements with generators,

1.B: require the State of Texas to make the investment to connect the ERCOT grid to the larger grids east and west of Texas,

1.C: require the State of Texas to guarantee loans for all generators, transporters or marketers on the ERCOT grid to build or contract for required capacity which can supply firm dispatchable supplies from generation plants or energy storage facilities to the ERCOT grid during a natural disaster or extreme weather conditions.

PLAN OVERVIEW

Executive Sponsor	**Kathy Garcia**
Name of Action / Project	Energy Market Redesign
Project Lead	David Kee
Action Plan Development Team	A cross section of business units including Energy Market Policy, Government Relations, Legal, Energy Supply & Market Operations, Power Generation and other impacted business units. Key participants include: David Kee, Diana Coleman, Kari Torres Meyer, Robert Nathan, Benjamin Ethridge, Kevin Pollo, Gabriel Garcia

OBJECTIVE

The objective of this plan is to work with the City of San Antonio and utility industry market participants to influence and advocate for policies that will enhance electric grid reliability within the ERCOT market.

RECOMMENDATION CATEGORY / DESCRIPTION

BENEFITS / REWARDS

The benefits of implementing this plan will ensure that CPS Energy and the City of San Antonio are represented and engaged in policy discussions seeking to address various problems that arose in the energy market during Winter Storm Uri. While this recommendation proposes to take certain actions during the 2023 Legislative Session, state regulatory agencies were directed to undertake a number of rulemakings to address policy concerns more immediately. Since June 2021, these policy discussions and rulemaking proceedings have been occurring simultaneously at the Public Utility Commission (PUC) and the Railroad Commission (RRC). The ERCOT stakeholder process has also taken action by way of market revisions and a substantial post-storm action item list that subcommittees and working groups have been working to address. Policy discussions of this nature also took place during the 87th Regular Legislative Session (2021) and subsequent called Special Sessions in 2021.

RISKS

No risks have been identified in regards to participating in the related policy discussions.

DETAILS

ACTION PLAN / PROJECT DETAILS

The work being performed on this plan includes the following:

- Meeting with subject matter experts across a number of business units to inform and receive input, aligning with CPS Energy leadership
- Meeting with policy makers and regulators to inform on and advocate for policies that enhance grid reliability
- Working with and through the Texas Public Power Association (TPPA) which represents municipally owned utilities
- Participating in agency hosted workshops and open meetings
- Submitting comments in agency rulemakings, either independently or through TPPA
- Working and collaborating with a wide array of energy market participants via the various regulatory stakeholder processes
- Providing real time updates and written summaries to CPS Energy leadership
- Contracting with an external consultant who has expertise in the energy market and previously served as ERCOT's independent market monitor to help advise on policy development and action

In November 2021, the PUC and RRC approved their respective rulemakings addressing the designation of critical natural gas infrastructure. This rulemaking is intended to ensure Texas' energy supply can withstand extreme weather events. However, the RRC's rulemaking did not address requiring a gas supply chain facility operator and gas pipeline facility operator to implement measures to prepare to operate during a weather emergency. The RRC will consider a future rulemaking to address natural gas weatherization rules.

In December 2021, the PUC released its "Market Redesign Blueprint" which is intended to provide policy guidance for the PUC and ERCOT going forward, with a focus on enhancing reliability and resiliency. Specific to the CEP recommendations:

1.A Reserve Capacity

- The PUC's goal has been to level the playing field by providing better pricing structures enabling additional dispatchable generation to be built, which they see as key to enhancing reliability while renewable deployment growth continues. This includes the consideration of backup or supplemental reserves and a Load Serving Entity (LSE) capacity obligation, which will require all entities serving customers to either own generation or document that they have firm contracts for power.

1.B Grid Interconnection

- Interconnection to the U.S. Eastern or Western grids is not included as part of the PUC's Blueprint, however ERCOT continually assesses its ability to import additional power through current operations via DC ties.

1.C State-backed guarantee loans to build or contract for required capacity

- The PUC's Blueprint seeks to bring market-based policies forward that will incent and boost investment in power generation, so enough power is available during both normal operations and extreme weather conditions. The goal is to use a market-based mechanism rather than a regulated loan program which is estimated to have the same benefits at the lowest cost to customers.

The Brattle Group, who is a third-party consultant to the PUC, will be providing analysis of the blueprint to the PUC and will provide recommendations on the impacts, costs and benefits of the blueprint. We expect that there will be multiple rulemaking proceedings opened next year to implement the changes.

EXECUTION

ASSOCIATED ROADMAP

Collect internal input on policy proposals, align with leadership

Participate in policy discussions

Advocate, educate and shape policy

Inform, provide real-time updates

IMPLEMENTATION TIMELINE

Advocacy in influencing and shaping the PUC Market Redesign Blueprint completed by December 2021.

Advocacy in influencing and shaping the PUC & RRC rulemakings on natural gas critical infrastructure completed by December 2021.

* Overall advocacy work on energy market policy will continue in perpetuity.

MILESTONES

Milestone	Target Date	Status / Comment
PUC and RRC approved their respective rulemakings addressing the designation of critical natural gas infrastructure.	November 2021	Complete
PUC released its draft “Market Redesign Blueprint”	December 15, 2021	Complete

DELIVERABLES

Deliverable	Target Date	Owner
CPS Energy’s & TPPA’s advocacy reflected in the PUC Market Redesign Blueprint	December 16, 2021	CPS Energy
Tracking document for rulemakings and protocol revisions	October 7, 2021	CPS Energy
Executive summary of energy market changes	December 31, 2021	CPS Energy

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Kathy Garcia	Executive Sponsor	12 hours a month
Beth Garza	Consultant	30 hours a month
Energy Market Policy	Lead Facilitating Team	60 hours a month per team member
Government Relations Legal Energy Supply & Market Operations Power Generation Financial Services	Working Group	40 hours a month

BUDGET

Time from consultant is covered in a monthly retainer.

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/17/2021
Executive Sponsor	Kathy Garcia	12/9/2021
Project Lead	David Kee	12/9/2021
Legal	Gabriel Garcia	12/9/2021
ESMO	Kevin Pollo	12/10/2021
Power Generation	Benjamin Ethridge	12/9/2021
Response Lead	Garrick Williams	12/16/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR CPS 2 FREE MARKET INTERFERENCE (NATURAL GAS SUPPLY STRATEGY)

CEP Recommendation: CPS Energy reevaluate their strategies and procedures for purchasing and transporting natural gas to assure adequate supplies of natural gas are available to their natural gas generation units critical for firming capacity during a crisis and for natural gas distribution to customers for heating.

Proposed action plan: CPS Energy continues to procure the amount of natural gas needed to ensure adequate supplies of natural gas are available to our natural gas-fired generation units and for natural gas distribution to customers for needs such as heating. We have reviewed our winter strategies and processes and are taking a multi-pronged approach to continue to assure adequate supplies of natural gas.

PLAN OVERVIEW

Business Unit/Area Name	**Frank Almaraz**
Name of Action/Project	Natural Gas Supply Strategy
Co-executive Sponsor	Cory Kuchinsky
Point of Contact	Kevin Pollo
Action Plan Development Team	Buck Guinn, Bruce Bordovsky

OBJECTIVE

Review our strategies and procedures for purchasing natural gas to continue to procure the amount of natural gas needed to supply our natural gas-fired generation units and for natural gas distribution to customers' homes and businesses.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

- Ensure we have access to the natural gas required to operate our generation plants and supply our customers during extreme weather events

RISKS

- Actual delivery of natural gas during an extreme weather event still depends on successful execution by the producers and pipeline operators, including implementation of necessary weatherization protection
- Local equipment failure or malfunction could yield isolated instances of interruption in natural gas delivery
- Increased contract capacity for natural gas transportation and/or storage services could result in higher costs to customers
- Limited number of natural gas pipelines with direct access to CPS Energy natural gas-fired generation units and to CPS Energy's natural gas transmission and distribution systems could limit the level of available redundancy and contingency planning solutions

DETAILS

ACTION PLAN / PROJECT DETAILS

CPS Energy continues to procure the amount of natural gas needed to ensure adequate supplies of natural gas are available to our natural gas-fired generation units and for natural gas distribution to customers for needs such as heating. We have reviewed our winter strategies and processes and are taking a multi-pronged approach to continue to assure adequate supplies of natural gas. Specific actions include the following:

- Secure natural gas transportation contracts sufficient to deliver gas needed to meet the expected usage associated with an extreme winter event
- Increase daily withdrawal capacity from natural gas storage
- Add additional natural gas storage capacity

EXECUTION

ASSOCIATED ROADMAP

- Review status and expiration dates of existing natural gas transportation contracts. Secure extensions or replacements for any contracts set to expire before conclusion of upcoming winter season
- Review status and expiration dates of existing natural gas storage contracts. Secure extensions or replacements for any contracts set to expire before conclusion of upcoming winter season
- Procure additional natural gas storage capacity
- Increase daily natural gas storage withdrawal capability

IMPLEMENTATION TIMELINE

Specific actions to be completed prior to December 1, 2021.

MILESTONES

Milestone	Target Date	Status/ Comment
Review of natural gas procurement plan for peak summer season with Energy Portfolio Steering Committee (EPSC)	April 27, 2021	Complete
Review of natural gas procurement activities during summer 2021 with EPSC	May, June, July 2021	Complete
Natural gas supply winter preparedness check-ins with CEO	Weekly	In progress
Natural gas supply winter preparedness check-ins with EPSC	Monthly	In progress

DELIVERABLES

Deliverable	Target Date	Owner
Executed natural gas transportation contracts	June 2021, Complete	ESMO
Executed natural gas storage contracts	June, August, October 2021, Complete	ESMO
Achieved targeted natural gas storage inventory levels	November 2021, Complete	ESMO

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Buck Guinn	Interim Director Fuels	400
Bruce Bordovsky	Gas Acquisition & Scheduling Manager	400

BUDGET

No incremental cost will be needed to complete the action plan. Reservation fees associated with any new natural gas transportation or storage contracts will be a fuel expense recovered through the fuel adjustment factor as the fees are incurred. Similarly, the cost to purchase natural gas is a fuel expense recovered through the fuel adjustment factor at the time the gas is used.

METRICS

- Ability to meet natural gas needs during the upcoming winter season (2021-2022)

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/15/2021
Executive Sponsor	Frank Almaraz	12/3/2021
Co-Executive Sponsor	Cory Kuchinsky	12/3/2021
Response Lead	Garrick Williams	12/8/2021
Business Area POC	Kevin Pollo	12/2/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR CPS 3 – ENERGY MARKET REDESIGN, PRICE MANIPULATION

CPS Energy and the City of San Antonio join with other cities, municipal utilities, and rural electric cooperatives to develop and pass legislation in the 2023 legislative session to eliminate the ability for the Public Utility Commission (PUC) through ERCOT to artificially manipulate the price of electric power and ancillary services on the grid and only allow ERCOT to have administrative and "clearing" authority over next day prices, real-time prices, and ancillary services on the grid.

PLAN OVERVIEW

Executive Sponsor	**Kathy Garcia**
Name of Action/Project	Energy Market Redesign, Price Manipulation
Project Lead	David Kee
Action Plan Development Team	A cross section of business units including Energy Market Policy, Government Relations, Legal, Energy Supply & Market Operations, and other impacted business units. Key participants include: David Kee, Diana Coleman, Kari Torres Meyer, Robert Nathan, Kevin Pollo, Gabriel Garcia

OBJECTIVE

The objective of this plan is to work with the City of San Antonio and utility industry market participants to advocate for additional pricing safety valves within ERCOT's energy market to protect customers from surging prices, particularly during an emergency.

During Winter Storm Uri, the PUC, which oversees ERCOT, authorized ERCOT to increase the wholesale "spot market" price of energy to its price cap of $9,000 per MWh, and ERCOT administratively held the prices at the maximum value for several days. The PUC and ERCOT prevented wholesale energy prices from being determined by the approved market pricing rules that were in place at the time and the price stayed artificially set at the maximum level during the final days of the storm, even as rolling outages had ceased, costing electric utilities and ultimately customers billions of dollars. The PUC's ERCOT Independent Market Monitor determined that the additional period of high prices resulted in $16 billion in overcharges to electricity providers.

RECOMMENDATION CATEGORY / DESCRIPTION

BENEFITS / REWARDS

The benefits of implementing this plan will ensure that CPS Energy and the City of San Antonio are represented and engaged in policy discussions seeking to address various problems that arose in the energy market during Winter Storm Uri. While this recommendation proposes to take certain actions during the 2023 Legislative Session, state regulatory agencies were directed to undertake a number of rulemakings to address policy concerns, including energy market pricing, more immediately. Since June 2021, these policy discussions and rulemaking proceedings have been occurring at the PUC. The ERCOT stakeholder process has also taken action by way of market revisions and a substantial post-storm action item list that subcommittees and working groups have been working to address. Policy discussions of this nature also took place during the 87th Regular Legislative Session (2021) and subsequent called Special Sessions in 2021.

RISKS

No risks have been identified in regard to participating in the related policy discussions.

DETAILS

ACTION PLAN / PROJECT DETAILS

The work being performed on this plan includes the following:

- Meeting with subject matter experts across a number of business units to inform and receive input, aligning with CPS Energy leadership
- Meeting with policy makers and regulators to inform on and advocate for policies that limit price manipulation during emergency events and protect customers from surging energy prices during scarcity events
- Working with and through the Texas Public Power Association (TPPA) which represents municipally owned utilities
- Participating in agency hosted workshops and open meetings
- Submitting comments in agency rulemakings, either independently or through TPPA
- Working and collaborating with a wide array of energy market participants
- Providing real time updates and written summaries to CPS Energy leadership
- Contracting with an external consultant who has expertise in the energy market and previously served as ERCOT Independent Market Monitor to help advise on policy development and action

On June 24, 2021, the PUC modified the value of its key wholesale pricing safeguard, the low system-wide offer cap (LCAP), in ERCOT by eliminating a provision that ties the value of the LCAP to the natural gas price index. The new pricing safeguard, when in use, will no longer be tied to uncapped natural gas prices, under which the LCAP price could exceed the maximum price for wholesale power, and instead will be set to a firm value.

On December 2, 2021, the PUC lowered the maximum price for wholesale power, the high system-wide offer cap (HCAP), in ERCOT from the current $9,000 per MWh to $5,000 per MWh, effective January 1, 2022.

Both the LCAP and HCAP ensure wholesale energy offers in the ERCOT market are within a range that protects the price market participants will pay for electricity during an emergency, while also maintaining incentives for demand response and generator investment.

In mid-December 2021, the PUC released its "Market Redesign Blueprint" which is intended to provide policy guidance for the PUC and ERCOT going forward. The Blueprint includes several proposals to address the shortcomings of the energy market that led to *ad hoc* pricing adjustments by ERCOT and the PUC during Winter Storm Uri. One important aspect of these proposals is to provide ERCOT with additional tools to stabilize the grid prior to entering emergency conditions in the future. Specific to this CEP recommendation, the Blueprint:

- Proposes additional market pricing reforms intended to provide pricing signals to market participants well in advance of an energy crisis
- Modifies existing market-based reliability mechanisms to bring generators online earlier as power supply conditions tighten in an effort to prevent an energy emergency event
- Proposes new reliability programs and services to provide an additional margin of reliability before, during, and after emergency grid conditions – this will give ERCOT more operational flexibility in managing potential emergency conditions

EXECUTION

ASSOCIATED ROADMAP

Collect internal input on policy proposals, align with leadership

Participate in policy discussions

Advocate, educate and shape policy

Inform, provide real-time updates

IMPLEMENTATION TIMELINE

Advocacy in influencing and shaping the PUC Market Redesign Blueprint completed by December 2021.

* Overall advocacy work on energy market policy will continue in perpetuity.

MILESTONES

Milestone	Target Date	Status / Comment
PUC modified the value of its key wholesale pricing safeguard, the low system-wide offer cap (LCAP), in ERCOT by eliminating a provision that ties the value of the LCAP to the natural gas price index.	6/24/2021	Complete
PUC lowered the maximum price for wholesale power, the high system-wide offer cap (HCAP), in ERCOT from the current $9,000 per MWh to $5,000 per MWh, effective January 1, 2022.	12/2/2021	Complete
PUC released its draft “Market Redesign Blueprint”	12/15/2021	Complete

DELIVERABLES

Deliverable	Target Date	Owner
CPS Energy’s & TPPA’s advocacy reflected in the PUC Market Redesign Blueprint	12/16/2021	CPS Energy
Tracking document for rulemakings and protocol revisions	10/7/2021	CPS Energy
Executive summary of energy market changes	12/31/2021	CPS Energy

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Kathy Garcia	Executive Sponsor	12 hours a month
Beth Garza	Consultant	30 hours a month
Energy Market Policy	Lead Facilitating Team	60 hours a month per team member
Government Relations Legal Energy Supply & Market Operations	Working Group	40 hours a month

Resource	Role	Estimated Work Hours
Power Generation Financial Services		

BUDGET

Time from consultant is covered in a monthly retainer.

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/17/2021
Executive Sponsor	Kathy Garcia	12/9/2021
Project Lead	David Kee	12/9/2021
Legal	Gabriel Garcia	12/10/2021
Response Lead	Garrick Williams	12/16/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR CPS 4 – PLANT OPERATIONAL PROBLEMS

CEP Recommendation: CPS Energy should emphasize and refocus on their long and distinguished history of operational excellence. From the outside, one can see how the historical winter storm exposed numerous operational problems across the fleet. However, it is the job of the Board of Trustees and the CPS Energy management to build the team to control what they can control, which is the generation, transmission, and distribution of electric power, and the purchase and distribution of natural gas.

PLAN OVERVIEW

Business Unit/Area Name	**Frank Almaraz**
Name of Action/Project	Plant Operational Problems (Generation Operational Improvements)
Co-executive Sponsor	**Benjamin Ethridge**
Point of Contact	Richard J. Urrutia Jr.
Action Plan Development Team	Richard J. Urrutia Jr., Larry Blaylock, Jeff Kruse

OBJECTIVE

The objective is to address operational issues experienced during the 2020-2021 winter period and provide sustainable solutions that will ensure for safe and reliable operation during future extreme weather events.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

Implementing this recommendation will improve generation unit reliability during winter storm events. Additional preparations based on experiences from the unprecedented winter event will harden critical systems in our generation plants.

RISKS

Additional costs could be incurred if the new Public Utility Commission (PUC) weatherization standards issued in 2022 require upgrade of weatherization improvements being performed this year.

DETAILS

ACTION PLAN / PROJECT DETAILS

In response to this recommendation, CPS Energy's Power Generation (PG) group will drive weatherization and fleet improvements to enhance the operational excellence practices in our plants to improve reliability & resiliency. As such, our Power Generation group is moving forward with three (3) initiatives in 2021 to improve plant performance:

1) We are implementing a weatherization improvement plan in preparation for the 2021-2022 winter season by December 2021. These activities are being managed on a plant-specific basis and work is ongoing at each site.
2) We are evaluating upgrade of aging burner systems & upgrading fan control systems. Spruce fan control system upgrade is in progress and will be completed by December 2021. Braunig burner system evaluations are underway to identify potential upgrades with work planned for 2022.
3) We have developed unit outage plans that will maximize CPS Energy's unit availability during December through February. These plans have been approved for the CY 2021-2022 outage season beginning October 2021. **(Complete)**

The South Texas Project team is also taking the following actions to improve plant performance:

1) Detailed inspection of all outside piping to ensure plant freeze protection is configured as designed and will upgrade as necessary by December 2021. **(Complete)**
2) Implement a revised Freeze Protection Program that has a single owner, enhanced procedures, processes, and database to track plant component and piping heat trace systems by December 2021. **(Complete)**

EXECUTION

ASSOCIATED ROADMAP

- In conjunction with this recommendation, Power Generation will also complete a winter preparedness program for each unit with certification to ERCOT by December 1, 2021. **(Complete)**

IMPLEMENTATION TIMELINE

Implement improvements before December 15, 2021.

MILESTONES

Milestone	Target Date	Status / Comment
Inspection of insulation & lagging currently installed on 6-inch diameter & smaller piping	11/1/2021	Complete
Purchase additional portable electric & propane heaters to reduce liquid fuel handling requirements	11/1/2021	Complete
Identify additional instrumentation devices piping requiring additional or new freeze protection.	11/1/2021	Complete
Design and materials purchased for electrical outlets to support new electric heaters across the plant sites.	12/15/2021	Complete
Third party engineering firm assessment of resiliency & weatherization. Their tasks include:	12/15/2021	
a. Walkdowns of PG locations to determine status/condition of weatherization.		Complete
b. Review of plant design and established weatherization guidelines.		Complete
c. Plant readiness checklist review.		Complete
d. Vulnerability assessment of shared systems.		Complete
e. Recommendations/Report preparations.		Complete
Repair insulation & lagging on 6-inch diameter & smaller piping.	11/15/2021	Complete
Update temporary winterization enclosure plans to improve performance.	11/15/2021	Complete
Evaluate options to increase on-site chemical storage capacities to allow for increased time between chemical deliveries.	12/15/2021	Complete
Update supplemental staffing plans to support extended duration events.	12/1/2021	Complete
Add freeze protection on at-risk instrumentation devices & piping.	12/1/2021	Complete
Reassess critical system spare parts inventory.	12/15/2021	Complete
Draft complete third-party engineering firm conceptual assessment of secondary fuel & secondary fuel storage options.	12/15/2021	Complete

DELIVERABLES

Each item above is expected to complete by December 15, 2021

Deliverable	Target Date	Owner
Third party engineering firm assessment of resiliency & weatherization.	12/15/2021	Jeff Kruse
Draft complete third-party engineering firm conceptual assessment of secondary fuel & secondary fuel storage options.	12/15/2021	Jeff Kruse

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Andrew Astudillo	Generation Duty Officer	240
Braunig Power Station	Power Plant	240
Spruce Power Station	Power Plant	240
Sommers Power Station	Power Plant	240
Rio Nogales Power Station	Power Plant	240
Commerce/CEC Sites	Renewable Site	240
Coal Yard	Coal Yard	240

BUDGET

Activity	Estimated $
Internal Labor	$2,000,000
Third Party Assessments	$1,200,000
Future PUC Weatherization Requirements	$32,200,000 (Capital) $13,800,000 (O&M)

METRICS

None

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/15/2021
Executive Sponsor	Frank Almaraz	12/3/2021
Co-Executive Sponsor	Benjamin Ethridge	12/3/2021
Response Lead	Garrick Williams	12/8/2021
Business Area POC	Richard J. Urrutia Jr.	12/3/2021

CEPR CPS 5 – UPGRADE AUTOMATED ROTATING OUTAGE PROGRAM

CEP Recommendation CPS 5: CPS Energy should revisit and upgrade the automated rotating outages program so that it is capable of handling larger load shed requirements.

Actions have been initiated to ensure systems and processes are in place to manage a Winter Storm Uri like event should it occur in the 2021-22 winter season.

PLAN OVERVIEW

Executive Sponsor	Paul Barham
Name of Action/Project	CEP Recommendation CPS 5 – Upgrade Automated Rotating Outages Program
Co-executive Sponsor	
Point of Contact	Rick Maldonado
Action Plan Development Team	James Trevino Zachary Lyle Melissa Gutierrez

OBJECTIVE

The objective is to enhance the rotating outages program capability to handle ERCOT load shed requests of at least 20,000MW. The increase in MW allows for shorter intervals and consistent rotation of load shed, which mitigates the impact to all customers.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

The benefit of implementing this recommendation is to minimize the impact to customers during a controlled outage event. A significant reassessment was performed on the critical circuit listing to minimize critical circuits to only those few most critical loads in order to minimize system wide impact. As additional interruptible circuits are made available for a controlled outage event, the cycle time between customer outages can be improved. The increase in megawatts allows for shorter intervals and consistent rotation of load shed, which mitigates the impact to all customers.

RISKS

The risk of implementing this recommendation is that the number of customers impacted by a controlled outage event may increase. As additional interruptible circuits are made available for a controlled outage event, customers who were not affected by controlled outages in February, may now be affected if a future controlled outage event is required. This can negatively impact CPS Energy's brand and reputation in the public square and reflect negatively on CPS Energy's residential customer satisfaction surveys.

DETAILS

ACTION PLAN / PROJECT DETAILS

Engage system vendor to enhance the load shed application. Coordinate with Managed Accounts to reassess critical load customers. Provide City's EOC and SAWS with an overview of load shed operation and management.

EXECUTION

ASSOCIATED ROADMAP

- Engage system vendor to design, test, and implement necessary system changes
- Engage the City's EOC & SAWS to provide an overview of load shed
- At the request of the Board of Trustees, engage a third party to conduct an assessment

IMPLEMENTATION TIMELINE

Implement improvements before the 2022 Winter season with consideration of longer-term program for infrastructure investments to create additional load shed control flexibility.

MILESTONES

Milestone	Target Date	Status / Comment
Engage system vendor to design, test, and implement changes to system	May 2021	Complete
Coordinate with Managed Accounts to engage SAWS & Provide an overview of load shed	June 2021	Complete
Review and update load shed operating procedures	July 2021	Complete

Provide the City's EOC with an overview of load shed	October 2021	Complete
Complete Third-Party Assessment of the load shed program enhancements	December 2021	Pending

Long Term – Pursue technology and infrastructure improvements over the long term, with funding, to improve the flexibility of the transmission and distribution systems to better target load shed across system to support more "crucial customer" exemptions while spreading load reduction across the entire system. This may be through the Advanced Metering Infrastructure (AMI), Distribution Automation (DA), or other programs. We have several efforts in progress including assessment of options through our AMI vendor. We are actively assessing options for DA projects that would allow shedding of partial circuits which would allow us to better work around critical loads in the system. We are working to apply additional sub-circuit switching and DA technology to increase controllability. **This will be a longer-term infrastructure investment.**

DELIVERABLES

Deliverable	Target Date	Owner
Third-party assessment of the load shed program enhancements	December 2021	CPS Energy

RESOURCES

PROJECT/ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
James Trevino	Customer Reliability	48
Control Systems	Analysis & Testing	660
PMO	Project Management	40
Third Party Resources	System Enhancements	475
Third Party Resources	Assessment	240

BUDGET

Activity	Estimated $
Internal Labor	$115,000
Third Party System Enhancements	$110,126
Third Party Assessments	$70,500

Longer term improvements are budgeted in existing projects already in flight such as the recloser deployment and control systems upgrade projects.

METRICS

Metric: Increased load shed system capability

Target: Load shed system capability Post Uri can allow the operator to pause, restart, & abort the application. The ERCOT request field can allow an input maximum of 5 digits. The rotating outages program capability can handle ERCOT load shed requests of at least 20,000MW.

Target achieved. The load shed system capability Post Uri can allow the operator to pause, restart, & abort the application. The ERCOT request field can allow an input maximum of 5 digits. The rotating outages program capability can handle ERCOT load shed requests of at least 20,000MW.

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/13/2021
Executive Sponsor	Paul Barham	11/22/2021
Response Lead	Garrick Williams	12/8/2021
Business Area POC	Rick Maldonado	11/22/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR CPS 6 – CIRCUIT LOAD & DESIGNATION REVIEW

CEP Recommendation CPS 6: CPS Energy should review the options to reduce the size of critical circuits, shift non-critical customers into interruptible circuits, and increase the number of interruptible circuits by reducing the size of non-interruptible circuits. This review of critical circuit load should be undertaken regularly and in coordination with other major critical service providers, such as fire departments, SAWS, and emergency shelter providers.

A major first effort has been performed to increase the load shed capacity (and the associated reduced impact to the average customer) through exempting only the most critical loads in the system.

PLAN OVERVIEW

Executive Sponsor	**Paul Barham**
Name of Action/Project	CEP Recommendation CPS 6 – Circuit Load & Designation Review
Co-executive Sponsor	
Point of Contact	Rick Maldonado
Action Plan Development Team	Zachary Lyle Melissa Gutierrez Clayton Kruse

OBJECTIVE

The objective is to minimize the impact to all customers by increasing the number of interruptible circuits available for controlled outages (Load Shed ordered by ERCOT) and coordinate impacts with other local agencies.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

The benefits of implementing this recommendation is to minimize the impact to customers during a controlled outage event. As additional interruptible circuits are made available for a controlled outage event, the cycle time between customer outages can be improved. The increase in megawatts allows for shorter intervals and consistent rotation of load shed, which mitigates the impact to all customers.

RISKS

The risk of implementing this recommendation is that the number of customers impacted by a controlled outage event may increase. As additional interruptible circuits are made available for a controlled outage event, customers who were not affected by controlled outages in February, may now be affected if a future controlled outage event is required. This can negatively impact CPS Energy's brand and reputation in the public square and reflect negatively on CPS Energy's residential customer satisfaction surveys.

DETAILS

ACTION PLAN / PROJECT DETAILS

Coordinate with Managed Accounts to reassess critical load customers and maximize circuits available for controlled outages to enable ability to effectively manage a Load Shed event similar to February 2021. Provide City's EOC and SAWS with an overview of load shed.

EXECUTION

ASSOCIATED ROADMAP

- Reevaluate loads to be prioritized for uninterrupted service during controlled outages to limit at a level that would support an ERCOT load shed event of 20,000MW
- Update Load Shed process and procedures to reflect operational changes made
- Coordinate with Managed Accounts to engage SAWS and identify critical assets (See also CEPR CPS 7)
- Engage the City's EOC & SAWS to provide an overview of load shed
- At the request of the Board of Trustees, engage a third party to conduct an assessment

IMPLEMENTATION TIMELINE

Implement improvements before the Winter 2022 season.

MILESTONES

Milestone	Target Date	Status / Comment
Coordinate with Managed Accounts to reassess critical load customers	Mar 2021	Complete
Coordinate with Managed Accounts to engage SAWS & provide an overview of load shed	June 2021	Complete
Review and update load shed operating procedures	July 2021	Complete
Provide the City's EOC with an overview of load shed	October 2021	Complete
Complete Third-Party Assessment of the circuit designation process & present findings to Board of Trustees Operations Oversight Committee (OOC)	October 2021	Complete
Provide preliminary draft of process and procedures for leadership review and approval	December 2021	Pending
Review and update interoperability procedure as needed (A-03)	December 2021	Pending
Complete business process procedure to include updating the categorization of critical circuits. Outline the process flow, responsibilities, and approvals required for quarterly and ad hoc updates to load shed circuits and update operating procedures as needed.	December 2021	Pending

DELIVERABLES

Deliverable	Target Date	Owner
Third-party assessment of the circuit designation process	October 2021	CPS Energy

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Zachary Lyle	Customer Reliability	225

Resource	Role	Estimated Work Hours
Melissa Gutierrez	Customer Reliability	170
System Operations	Analysis	120
Third Party Resources	Assessment	117

BUDGET

Activity	Estimated $
Internal Labor	$110,630
Third Party Assessments	$28,105

METRICS

Metric: Total Count of Interruptible Circuits

Target: Total count of interruptible circuits Post Winter Storm Uri is greater than the total count of interruptible circuits Pre-Winter Storm Uri

Target achieved. Total count of interruptible circuits Post Winter Storm Uri is 389. Total count of interruptible circuits Pre-Winter Storm Uri was 241. The variance is an increase of 148.

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/13/2021
Executive Sponsor	Paul Barham	11/22/2021
Response Lead	Garrick Williams	12/9/2021
Business Area POC	Rick Maldonado	11/22/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR CPS 7 - SAWS CRITICAL SITES FOR CIRCUIT REDUNDANCY

CPS Energy should review opportunities to supply power to SAWS pump stations and other critical infrastructure where critical circuits are not available or to feed these locations from dual circuits.

PLAN OVERVIEW

Executive Sponsor	**Paul Barham**
Name of Action/Project	CEPR CPS 7 - SAWS Critical Sites for Circuit Redundancy
Co-executive Sponsor	**Richard Medina**
Point of Contact	George Tamez
Action Plan Development Team	Rachel Krepps, Trieu Vo, Clayton Kruse, Melissa Gutierrez

OBJECTIVE

For SAWS most critical facilities, evaluate additional distribution infrastructure required and opportunities that could be created thru dual circuits, and automatic throw over (ATO) equipment.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

- Targeting SAWS designated critical facilities for improved resiliency and reliability
- Analysis will define additional distribution infrastructure to reinforce operational readiness to identified SAWS critical sites
- Dual feeds will increase redundancy of circuit feeds and capacity
- Automatic Transfer capabilities will expand the service availability thru automated load transfer equipment and availability of dual circuits
- Provide higher reliability and resiliency to SAWS pump stations and other critical infrastructure
- Detailed review of the sites will provide any opportunities for improved service
- Coordination of this work with SAWS efforts around back-up generation in CEPR SAWS 2 & 3

RISKS

- Infrastructure or equipment failure for an extended outage
- Unforeseen obstacles or costs to deploying infrastructure and equipment in the field
- Only provides a partial solution to select facilities and does not address a grid blackout event

DETAILS

ACTION PLAN / PROJECT DETAILS

For SAWS most critical facilities, evaluate additional distribution infrastructure required and opportunities that could be created thru dual circuits, and automatic throw over (ATO) equipment.

Item 1: Establish list of critical facilities from SAWS.

- SAWS to provide a targeted list of SAWS pump stations or other critical infrastructure. **Completed**.
- Seven (7) targeted sites

Item 2: CPS Energy to perform a high-level review of the seven (7) sites. Establish current configuration of circuits availability and automatic transfer capabilities and identify opportunities. **Completed**.

- Five (5) of the seven (7) sites have dual circuits and transfer capabilities
- Two (2) of the seven (7) sites are identified for opportunity for additional analysis

Item 3: CPS Energy to analyze all 7 sites for a detailed review of each site to include: substation redundancy, common infrastructure review, need for an automatic throwover equipment, and an operational impact review from SAWS on operations during a transfer event from the primary to the backup feed. **Completed.**

- Established a structure for the narrative on describing the proposed recommendations

Item 4: CPS Energy to provide SAWS with a review of analysis, list of proposed recommendations per site and gather feedback from SAWS on opportunities. **Completed.**

Item 5: CPS Energy to provide a review of estimated costs and scope to complete infrastructure improvements with SAWS. **Completed.**

Item 6: CPS Energy to incorporate SAWS' approved list of recommendations into ongoing infrastructure improvement plans. **Targeted Dec 15th completion.**

Item 7: CPS Energy to continue support of SAWS in evaluation of sites for hardening of electrical infrastructure and of back-up generation application and interconnection. **On-Going as needed.**

EXECUTION

ASSOCIATED ROADMAP

Communication session→ Opportunity analysis→ Customer review→ Solutions implementation

IMPLEMENTATION TIMELINE

Complete customer review of recommended options by December 15, 2021.

MILESTONES

Milestone	Target Date	Status / Comment
Obtain targeted list of critical sites	6/1/2021	Complete
Complete location and circuit mapping	8/1/2021	Complete
Conduct Field investigations	9/1/2021	Complete
Complete narrative template	10/1/2021	Complete

DELIVERABLES

Deliverable	Target Date	Owner
Provide SAWS with a summary of each site with opportunities based on a review of distribution circuit redundancy and load transfer capabilities at SAWS Critical sites for improved distribution level reliability and resiliency.	12/13/2021	CPS Energy

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Rachel Krepps	Engineering Analysis	224
Trieu Vo	Distribution Planning	84
George Tamez	Grid Transformation & Planning	24
Clayton Kruse	Managed Accounts	12
Melissa Gutierrez	Customer Reliability	8
Third Party Resources	Assessment & Analysis	300

BUDGET

Activity	Estimated $
Internal Labor	$32,000
Third Party Assessments	$29,000

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/14/2021
Executive Sponsor	Paul Barham	12/8/2021
Co-Executive Sponsor	Richard Medina	12/8/2021
Response Lead	Garrick Williams	12/10/2021
Business Area POC	George Tamez	12/8/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR CPS 8, CPS 9, EOC 18, EOC 19 & SAWS 8 - CUSTOMER & STAKEHOLDER COMMUNICATIONS

The communications recommendations made by the CEP will be addressed in the revised Emergency Communications plan and through enhanced messaging to include clear calls to action and continued collaboration with our partner communicators.

PLAN OVERVIEW

Executive Sponsor	**Rudy Garza**
Name of Action/Project	Customer & Stakeholder Communications
Co-executive Sponsor	
Point of Contact	Melissa Sorola
Action Plan Development Team	Christine Patmon, Kelly Kuhle

OBJECTIVE

The objective of this plan is to update our crisis communications plans to reflect process for communicating with customers and stakeholders in times of emergencies.

RECOMMENDATION CATEGORY/DESCRIPTION

DESCRIPTION

(CPS 8) Develop a cohesive, comprehensive, and clear emergency communications protocol in collaboration with the City of San Antonio Emergency Operations Center (EOC) with input from community professionals. In developing the protocol, CPS Energy should consider:

Tailoring messaging to what is most critical for the customer's service and safety and focus on what is most relevant to the organization's mission.

Evaluating the effectiveness of calls for conservation and consider how effectiveness can be enhanced, by modifying timing, communication methods, and perhaps even reporting real time progress on conservation.

Issuing an advance notification process to contact each customer when there is a risk of mandatory load shed and rolling outages. These notifications should:

- Be coordinated with the emergency operations center
- Be provided with a reasonable advance notice to prepare and make alternative arrangements
- Indicate if customer is on a circuit that is NOT critical and may lose power if rolling outages occur (only possible if notifications are personalized by account)
- Advise what the customer should do if they lose power, such as places they can go or whom to call for assistance

(CPS 9) In concert with City and other local agencies develop and implement an emergency readiness year-round campaign, building out the framework of Ready South Texas. The aim should be that residents know how to prepare for an emergency as well as they know the number 911.

(EOC 18) Ensure CPS and SAWS communications are coordinated through the JIC to improve situational awareness for all entities involved.

(EOC 19) Coordinate daily media briefings by and between CoSA, County officials, CPS and SAWS.

(SAWS 8) Develop systems and protocols to have one coordinated messaging channel between EOC, SAWS, and CPS Energy for emergencies.

BENEFITS/REWARDS

The benefits of implementing this enhanced communications plan will provide customers with the information they need to plan, prepare, and withstand energy emergencies to keep them safe and informed. The continued collaboration with partner public information officers (PIOs) from the City, County, SAWS, and the EOC will benefit the community by having one unified message that we will be able to amplify with our respective reach.

RISKS

The risks of not revising the communications plan to include the CEP recommendations will not advance the improvements we need to effectively communicate with our customers during times of crisis.

DETAILS

ACTION PLAN / PROJECT DETAILS

(CPS 8) The work currently being done to revise the Emergency Communications Plan includes the following:

- Redefined roles and responsibilities for team to ensure coverage of all functions during an emergency
- Revised message templates to include clear calls to action for customers in the event of an emergency
- Update to include new team members' contact information
- Identification of remote work locations if needed
- Update to include social media strategy for emergency situations

The Winter Reliability and Resiliency campaign that will launch in December will include relevant and helpful information for customers to be prepared for the winter weather to include safety and energy savings tips. The campaign is also being prepared to include safety tips to cover generator safety and steps to safely power up your home once power is restored.

(CPS 9, EOC 18, EOC 19, SAWS 8) The work we are doing collaborative with our partner PIOs ensures we are ready to stand up at the EOC's Joint Information Center (JIC) and we are committed to serving in that role when needed. We will complete joint training on the JIC on Tuesday, December 14, 2021. We are also working collaboratively on a joint readiness campaign that would kick off in January 2022.

Finally, there is a need for ongoing training for our team and along with table top exercises and the GridEx training, we will complete additional outside training (to be identified and secured.)

EXECUTION

ASSOCIATED ROADMAP

CPS 8, CPS, 9, EOC 18, EOC 19, SAWS 8

IMPLEMENTATION TIMELINE

The plan is currently being reviewed and revised in coordination with our outside communications agency.

The plan will be completed by the end of December 2021.

The joint emergency preparedness campaign will be completed in January 2022.

MILESTONES

Milestone	Target Date	Status / Comment
Conduct communications agency meeting to review and refine the plan	Weekly	Ongoing
Conduct partner public information officers meeting to share information and identify opportunities to work collaboratively	Monthly	Ongoing

DELIVERABLES

Deliverable	Target Date	Owner
Revised Emergency Communications Plan	December 31, 2021	Melissa Sorola
Winter Reliability & Resiliency Communications Campaign	December 31, 2021	Melissa Sorola, Christine Patmon, Kelly Kuhle
Joint campaign with CoSA, County, and SAWS on emergency preparedness	January 2022	Melissa Sorola, Christine Patmon

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Melissa Sorola	Lead	12 hours a month
KGB Texas	Communications Consultant	12 hours a month
Christine Patmon Kelly Kuhle Adrian Garcia	Team	6 hours a month per team member

Resource	Role	Estimated Work Hours
Carroll Elter		

BUDGET

Time from communications consultant is covered in monthly retainer. Additional costs are estimated at around $30k for video production.

METRICS

None

APPROVAL

Title	Name	Date
Interim President & CEO/ Executive Sponsor	Rudy Garza	12/17/2021
Response Lead	Garrick Williams	12/13/2021
Business Area POC	Melissa Sorola	12/10/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR EOC 1

Assist the City of San Antonio (CoSA) in updating the Hazard Mitigation Action Plan (HAP) to include planning for a prolonged winter storm event, prolonged power outages, prolonged water outages, and a combination of the previous three events.

PLAN OVERVIEW

Executive Sponsor	**Shanna Ramirez**
Name of Action / Project	CEPR EOC 1
Co-executive Sponsor	**Paul Barham**
Point of Contact	Josh Dean
Action Plan Development Team	Blaize Skocny, William McCarson, Melissa Gutierrez

OBJECTIVE

The City of San Antonio's Hazard Mitigation Action Plan (HAP) is a single jurisdictional plan that is updated every five years. Numerous entities and businesses participated as stakeholders in the plan, including CPS Energy and numerous other public and private entities. These groups provide valuable input into the planning process. CPS Energy has always participated in the HAP.

RECOMMENDATION CATEGORY / DESCRIPTION

REWARDS

- Protect public safety and prevent loss of life and injury
- Mitigate risk to current and future development
- Maintain community continuity and strengthen the social connections that are essential for recovery
- Effective and efficient interagency responses to hazards
- Prevent damage to our community's unique economic, cultural, and environmental assets
- Minimize operational downtime and accelerate recovery of government and community after disasters
- Reduce the costs of disaster response & recovery, and the exposure to risk for first responders
- Help accomplish other community objectives such as infrastructure protection, open space preservation, and economic resiliency

RISKS

- Covid-19 restrictions could hinder timelines and effectiveness
- Confidentiality of information
- Appropriate funding or resources
- Conflicts in priority
- Change in personnel

DETAILS

ACTION PLAN / PROJECT DETAILS

- CPS Energy reviewed the HAP and meets with CoSA monthly to discuss any related opportunities to update the plan
- CPS Energy will participate in the update of the HAP (approximately 2025)
- Business Continuity will coordinate with all CPS Energy Business Units needed for the process
- Proactive mitigation leads to sustainable, cost-effective projects
- CPS Energy will ask to include a prolonged winter storm event, prolonged power outages, prolonged water outages, and a combination of the previous three events
- Development of more sustainable and disaster-resistant communities

EXECUTION

ASSOCIATED ROADMAP

- CPS Energy will participate in the next HAP update when started by CoSA

IMPLEMENTATION TIMELINE

- We will work with CoSA and provide a completion date

MILESTONES

Milestone	Target Date	Status / Comment
Identify stakholders to participate in HAP development process	Every 5 Years	Last Updated in 2020
Notification of finalized HAP	1 month after	
Update Business Continuity Plan based on findings	45 days after	

DELIVERABLES

Deliverable	Target Date	Owner
Ensure HAP includes planning for most recent events (Prolonged winter storm, power outage, water outage and a combination)	Annually	CoSA EOC
Documented Lessons Learned	1 month after	CoSA EOC
Updated Business Continuity Plan	1 month	CPS Energy

RESOURCES

PROJECT/ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
William McCarson	Business Continuity	80
Blaize Skocny	Incident Response & Business Continuity	80

BUDGET

- Employees time, however, the project is a requirement of CPS Energy staff

METRICS

- Better communication between all parties and an improved response to events affecting our customers
- Tracking of Lessons Learned
- Updating Business Continuity Plans

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/3/2021
Executive Sponsor	Shanna Ramirez	11/12/2021
Co-Executive Sponsor	Paul Barham	11/12/2021
Response Lead	Garrick Williams	11/29/2021
Business Area POC	Josh Dean	11/12/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR EOC 2 - BACKUP COMMUNICATION DEVICES/DATA SERVICE

CEP Recommendation: CoSA should identify backup devices to cellphones and other mobile devices. 4G towers are more reliable than 5G towers, which will fail during major power outages. Be familiar with the plan with CoSA telephone and data service providers for the transition to emergency services in the event of provider outages.

CPS Energy seeks to leverage our hosted cellular services, Satellite phones, and Harmony system to maintain chain of command and operations. Utilize City/County 2-way radio (EDACS) system for transition to emergency communications in the event the Harmony system fails pre activation of new 2-way radio system or Alamo Area Regional Radio System (AARRS).

PLAN OVERVIEW

Business Unit/Area Name	**Vivian Bouet**
Name of Action/Project	URI & EOC Operations (Backup Communication Devices/Data Service)
Co-executive Sponsor	Richard Medina
Point of Contact	Evan O'Mahoney
Action Plan Development Team	Jerome Decuir, Joseph Deuel, Bob Sanders, David Saenz, Leewan Torres, Raven Mirabeau

OBJECTIVE

Improve CPS Energy communications capabilities by leveraging coordination between existing means of communications to ensure CPS Energy leadership has the means to communicate inside and outside the company to maintain business continuity during events that interrupt CPS Energy power services.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

By leveraging coordination between existing communications means and systems including cellular, satellite, and LMR CPS Energy is expected to maintain reliable communications across the Enterprise to maintain business continuity during extreme events where the grid is jeopardized, and services are affected across a large part of the service area.

For Cellular Voice and Data services:

Cellular service on the public safety carrier networks will appear seamless to the end users, priority and preemption should improve overall availability of cellular services, especially during critical events when service would normally be impacted.

Splitting of the Cellular services between the two major service providers ensures that in the event of a failure one network will not affect all users. It is extremely unlikely that both major carriers would experience outages at the same time. This further enhances CPS Energy's ability to continue to communicate during adverse conditions.

For Satellite phone users:

Current user group and distribution list is updated.

For Land Mobile Radio Users:

The Harmony Land Mobile Radio (LMR) system is already a robust high available platform even considering its age. Recent maintenance activities have improved service availability of the system.

The AARRS LMR replacement system will have greater coverage leverages new technology has better radios with more functions to support radio to radio and radio to dispatcher communications. For continuity purposes all talk groups identifiers have been carried over from the Harmony naming conventions.

RISKS

For Cellular Voice and Data services:

When migrating subscribers over to new plans it is possible to miss individual users

Even with the upgrade to public safety grade accounts, prolonged outage events like Storm URI could result in a failure of the cellular network. "Small" cell and "Pico" cell sites do not have extended battery backup capabilities. In some instances, "Macro" cell sites also lack generator backup to support their battery backup systems for prolonged outage periods. This will result in spotty coverage in and around Bexar County and the surrounding counties where CPS Energy employees reside during a prolonged outage event.

For Satellite phone users:

Limited to no risk. Based on Satellites orbiting the plant and the frequencies they use they are not affected by extreme weather events but do require outside exposure to get a good signal.

For the Land Mobile Radio Users:

Due to the advanced age (18+) of the Motorola IDEN System (Harmony), the possibility of total system failure. The system will continue to degrade with minimal ability to replace key components due to its discontinued manufacturer support. This will result in key personnel will not be able to communicate during critical events. This could delay plant startups, continued operations of the plants. Load shed events would be delayed and require runners to travel from location to location to relay commands. Restoration teams would also be delayed in restoring service during outage times. Teams needed to restore the SCADA and Fiber Communications networks would not be able to effectively communicate to restore services in a timely fashion.

DETAILS

ACTION PLAN / PROJECT DETAILS

Complete an Incident Action Plan (IAP) and create an Incident Radio Communications Plan (ICS-205) that details the process and procedure on how and when users move from their primary devices to their reserve or secondary devices along with coordination and distribution of devices.

Establish all CPS Energy Cellular Communication users using AT&T and Verizon Wireless services to the respective public safety grade accounts. This will improve resiliency and improve service availability during incidents that affect the whole grid. Executive Leadership will still activate Satellite Phones in the event of a failure of the Cellular Network. Operations command and control and field resources will leverage their LMR radios for communications when cellular service cease to work.
Land Mobile Radio System:

Pre June of 2022 – Harmony LMR

Continue to maintain and support this system until AARRS is activated and cutover. In the event of a failure of the Harmony prior to AARRS going operational. CPS Energy will leverage contingency radios on the City/County Radio System (EDACS). Only 234 radios are available, a deployment plan is spelled out in the IAP.

Post June 2022 – AARRS LMR

Migration to AARRS which will have higher reliability and resiliency due to design and technology advancements.

EXECUTION

ASSOCIATED ROADMAP

Perform annual tabletop exercise to validate process and procedure to migrate users from Cellular to Satellite / LMR.

Update and adjust as necessary current process, procedures and activation lists.

IMPLEMENTATION TIMELINE

For Cellular Voice and Data Users:

- Complete migration of all Verizon cellular users to public safety network. Completed.
- Complete AT&T hardware upgrades. **Completed**.
- Complete migration of AT&T cellular users to FirstNet. **Scheduled to complete by the Mid - 2022.**

For Satellite Phone Services:

- Satellite phone services are established and will remain in effect for executive leadership and revised annually or as necessary.

For Land Mobile Radio System (LMR):

- Complete the Harmony LMR audits and corrective actions. Completed.
- Harmony DR plan update. **Completed**.
- Complete the Incident Action Plan (IAP) and Incident Radio Communications Plan (ICS-205). **Completed**.
- Complete EDACS radio talk groups for CPS employees during any incident. **Completed**.
- Pre assign Radio handsets for distribution during any incident when the IAP is activated. **Completed**.

MILESTONES

Milestone	Target Date	Status/ Comment
Create IAP and ICS-205 plan and procedures	12/1/2021	Complete
Migrate AT&T cellular users to FirstNet	Mid - 2022	In Progress
Harmony DR update and EDACS fall back readiness	12/1/2021	Complete

DELIVERABLES

Deliverable	Target Date	Owner
Migrate Verizon cellular services to public safety cellular services	12/1/2021	CPS Energy
Upgrade AT&T cellular users to 4G handsets	12/1/2021	CPS Energy
Migrate AT&T cellular users to FirstNet	Mid - 2022	CPS Energy
Update the CPS Energy Harmony DR Plan	12/13/2021	CPS Energy
Install Dispatch Consoles for EDACS	12/17/2021	CPS Energy
CPS Energy IAP and ICS-205 plan	12/13/2021	CPS Energy

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Joseph Deuel	Lead	120
Bob Sanders	Contributor	16
Jerome Decuir	Review	32
Leewan Torres	Contributor	160
Raven Mirabeau	Contributor	80
David Saenz	Contributor	16

BUDGET

- Department O&M for Employees time ~ $200K
- 30 – EDAC Radios and Software ~ $300K
- Harmony Radio parts ~ $50K

METRICS – WORK IN PROGRESS

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/17/2021
Executive Sponsor	Vivian Bouet	12/10/2021
Co-Executive Sponsor	Richard Medina	12/10/2021
Response Lead	Garrick Williams	12/14/2021
Business Area POC	Evan O'Mahoney	12/10/2021
Business Area POC	Jerome Decuir	12/10/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR EOC 3 - CITY OF SAN ANTONIO (COSA) FACILITIES GENERATORS

CoSA should prioritize the purchase of generators to ensure key city facilities are able to operate during a major winter or heat event.

PLAN OVERVIEW

Executive Sponsor	Paul Barham
Name of Action/Project	City of San Antonio (CoSA) Facilities Generators
Co-executive Sponsor	N/A
Point of Contact	Karma Nilsson
Action Plan Development Team	Clayton Kruse, Rhonda Krisch, Zach Lyle, Melissa Gutierrez

OBJECTIVE

Provide support and assistance to CoSA during their prioritization and identification processes as they work toward a plan for back-up generation at some of their facilities to operate during a major winter or heat event.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

Improved relationships, resiliency and customer satisfaction. Providing energy information for our owner and customer to help them to be able to provide service consistently to our community during a major energy event. We will provide support to assist CoSA with getting the solution they select through the interconnection and installation process.

RISKS

On-site generation installations are significant investments in upfront cost accompanied by ongoing maintenance and operating costs. CPS Energy does not have insight if CoSA has sufficient budgeted funds to cover the sites being considered to accomplish this recommendation.

CoSA has identified and prioritized facilities for back-up generation needs but CoSA is unable to share their list with CPS Energy at this time.

CPS Energy will support CoSA through the interconnection and installation of their solution. Depending on the solution CoSA selects, CPS Energy may also work with CoSA on identifying and implementing opportunities to sell energy to CPS Energy and/or the market during high energy pricing times.

If CoSA selects a solution that requires new natural gas service, it may take some time to implement service at their priority sites. There is a risk that CoSA will most likely have to go through at least one additional winter and summer without this backup generation in place. At this time, CoSA is looking at potentially selecting a faster diesel generation solution.

CoSA's ability to obtain funding and time needed to install the systems may prevent them from obtaining back-up generation prior to the next significant event.

Current global material supply shortages may further delay implementation for CoSA.

DETAILS

ACTION PLAN/PROJECT DETAILS

- Set check-ins with CoSA on project
- Request timeline from CoSA for identifying sites
- Identify budget bandwidth and target number of sites for CoSA
- Provide information on resiliency rate and program
- Set expectations for natural gas availability
- Provide cost and time estimates if needed for natural gas or electric service to sites
- Set expectations for potential effects of global material supply shortages

EXECUTION

ASSOCIATED ROADMAP

Serve as energy expert → provide information → work with CoSA selected vendor

IMPLEMENTATION TIMELINE

Complete site selections and prioritization by December 31, 2021.

MILESTONES

Milestone	Target Date	Status/ Comment
CoSA select and finalize priority sites for back-up generation	October 2021	Complete
CoSA releases list of priority sites for back-up generation	October 2022	Projected release date
Prioritize CoSA identified sites to support customer needs	November 2022	Pending

DELIVERABLES

Deliverable	Target Date	Owner
List of CoSA sites by priority	October 2022	CoSA EOC
Executive Support to expedite	Ongoing	CoSA

RESOURCES

PROJECT/ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Karma Nilsson	Business Area POC	10 hours
Account Management	Customer contact	10 hours
Local Government Relations	Customer contact	20 hours
Finance	Billing & financial settlement	4-8 hours
Energy Supply & Market Operations	Possible QSE & market connection	4-8 hours
Gas Solutions	Availability, construction estimates	10 hours

BUDGET

CPS Energy Budget – no budget is needed for this CEP recommendation to identify sites.

METRICS

- List and prioritization completion date

APPROVAL

Title	Name	Date
Interim CEO	Rudy Garza	11/23/2021
Executive Sponsor	Paul Barham	10/29/2021
Response Lead	Garrick Williams	11/17/2021
Business Area POC	Karma Nilsson	10/29/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR EOC 8

Work with the City of San Antonio (CoSA) to identify contingency plans for catastrophic incidents where a significant percentage of workers are not able to work remotely due to power outages.

PLAN OVERVIEW

Executive Sponsor	Shanna Ramirez
Name of Action/Project	CEPR EOC 8
Co-executive Sponsor	**Paul Barham**
Point of Contact	Josh Dean
Action Plan Development Team	Blaize Skocny, William McCarson

OBJECTIVE

CPS Energy will work with the city Emergency Operations Center (EOC), SAWS, and Bexar County Office of Emergency Management (BCOEM) to plan disaster scenarios and then participate with the San Antonio Office of Emergency Management (SAOEM) in exercises addressing those scenarios. We will work with the EOC to create plans for catastrophic incidents where a significant percentage of workers cannot work remotely due to power outages. We will then exercise those scenarios. We have already planned and outlined applicable training for the remainder of this year and will add these scenarios to future training.

RECOMMENDATION CATEGORY/DESCRIPTION

REWARDS

- Continuity of work
- Maintain critical operations and minimize loss
- Protects resources
- Minimizes customer impact
- Identifies key staff
- Updates Business Continuity Plans based on findings

RISKS

- Covid-19 restrictions could hinder timelines and effectiveness
- Confidential information could be exposed

- Funding and/or resources may not be appropriate for critical needs
- High priority activities may be in conflict, jeopardizing the ability to complete critical tasks
- Changes in personnel may impact the completion of critical activities

DETAILS

ACTION PLAN / PROJECT DETAILS

- CPS Energy will host two Texas A&M Engineering Extension Service (TEEX) training sessions a year and will include SAWS, CoSA, BCOEM, and other local governments
- CPS Energy will include SAWS, CoSA, BCOEM, and other local governments in CPS Energy led training such as GridEx and other internal training
- CPS Energy Business Continuity and Emergency Management will meet with SAWS Emergency Management, CoSA EOC, BCOEM, Texas Department of Emergency Management (TDEM), and other local governments once a month to check in and help make sure CEP findings that involve CPS Energy, SAWS, and CoSA are being addressed

EXECUTION

ASSOCIATED ROADMAP

- 5/11/2021 – The Texas Torrent: 2021 Alamo Area Community Flood Resilience tabletop exercise with a focus on pre-incident and information sharing protocols; incident response protocols; collaboration and coordination between public and private sector partners; public messaging and media relations; and immediate, short-term, and long-term recovery operations
    - Participants included CPS Energy, BCOEM, SAOEM, San Antonio Fire Department (SAFD), San Antonio Police Department (SAPD), San Antonio River Authority (SARA), and many more
- 6/02/2021 – The SAOEM, in conjunction with the San Antonio Metropolitan Health District (SAMHD), BCOEM, CPS Energy, and SAWS, participated in an Extreme Heat Tabletop Exercise
    - This exercise provided the opportunity for stakeholders to engage in open and collaborative discussions regarding pre-incident information sharing, incident response protocol, a collaboration between agencies, and immediate and short-term recovery operations
- 7/28/2021 – A joint Tabletop Exercise was conducted with SAWS and CPS Energy
    - The purpose of the exercise was to practice interagency communication during a simulated emergency event sequence scenario
- Staff meets with CoSA, SAWS, TDEM, BCOEM, and others monthly to discuss the CEP recommendations and how to proceed forward

IMPLEMENTATION TIMELINE

- These types of training will be conducted annually

MILESTONES

Milestone	Target Date	Status / Comment
Conduct Joint Training Sessions	Annually	
Joint Training Sessions Lessons Learned Follow-up	1 month after	
Conduct assessment of communications and working relationship growth between CoSA SAWS and other local governments	Bi-annual	
Update Business Continuity Plan based on findings	45 days after	

DELIVERABLES

Deliverable	Target Date	Owner
Provide feedback on Joint Training Sessions and share training documents	Annually	CoSA EOC
Documented Lessons Learned	1 month after	CoSA EOC
Updated Business Continuity Plan	1 month	CPS Energy

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
William McCarson	Business Continuity	40
Blaize Skocny	Incident Response & Business Continuity	40

BUDGET

- Annual Joint Training Meeting - $2,400

METRICS

- Better communication between all parties and an improved response to events affecting our customers tracking of lessons learned
- Lessons learned will be corrected in our business continuity plan

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/3/2021
Executive Sponsor	Shanna Ramirez	11/12/2021
Co-Executive Sponsor	Paul Barham	11/12/2021
Response Lead	Garrick Williams	11/29/2021
Business Area POC	Josh Dean	11/12/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR EOC 10

Collaborate with the City of San Antonio (CoSA) to develop specific planning, training, and exercises focusing on long-term power and water loss due to unforeseen events or scenarios.

PLAN OVERVIEW

Executive Sponsor	**Shanna Ramirez**
Name of Action/Project	CEPR EOC 10
Co-executive Sponsor	**Paul Barham**
Point of Contact	Josh Dean
Action Plan Development Team	Blaize Skocny, William McCarson, Melissa Gutierrez

OBJECTIVE

CPS Energy will work with the city Emergency Operations Center (EOC) and SAWS to plan disaster scenarios addressing natural disasters. Coordinate with the San Antonio Office of Emergency Management (SAOEM), SAWS, and CPS Energy training with Texas A&M Engineering Extension Service (TEEX).

RECOMMENDATION CATEGORY/DESCRIPTION

REWARDS

- Evaluates overall incident preparedness
- Clarifies roles and responsibilities during an incident
- Assess the capabilities of existing resources
- Identify deficiencies in business continuity plans, including technical, planning & procedural
- Update Business Continuity Plans based on findings

RISKS

- Covid-19 restrictions could hinder timelines and effectiveness
- Confidential information could be exposed
- Funding and/or resources may not be appropriate for critical needs
- High priority activities may be in conflict, jeopardizing the ability to complete critical tasks
- Changes in personnel may impact the completion of critical activities

- Risk of not addressing an event that could occur

DETAILS

ACTION PLAN / PROJECT DETAILS

- CPS Energy will host two TEEX training sessions a year and will include SAWS, CoSA, and other local governments
- CPS Energy will include SAWS, CoSA, Bexar County Office of Emergency Management (BCOEM), and other local governments in CPS Energy led training such as GridEx and internal CPS Energy training
- CPS Energy Business Continuity and Emergency Management will meet with SAWS Emergency Management, CoSA EOC, BCOEM, and other local governments once a month to check in and help make sure findings from the CEP that involve CPS Energy, SAWS, CoSA, and BCOEM are being followed up on

EXECUTION

ASSOCIATED ROADMAP

- 5/11/2021 – The Texas Torrent: 2021 Alamo Area Community Flood Resilience tabletop exercise focuses on pre-incident and information sharing protocols; incident response protocols; collaboration and coordination between public and private sector partners; public messaging and media relations; and immediate, short-term, and long-term recovery operations
    - Participants included CPS Energy, BCOEM, San Antonio Office of Emergency Management (SAOEM), San Antonio Fire Department (SAFD), San Antonio Police Department (SAPD), San Antonio River Authority (SARA), and many more
- 6/02/2021 – The SAOEM, in conjunction with the San Antonio Metropolitan Health District (SAMHD), BCOEM, CPS Energy, and SAWS, participated in an Extreme Heat Tabletop Exercise
    - This exercise provided the opportunity for stakeholders to engage in open and collaborative discussions regarding pre-incident information sharing, incident response protocol, collaboration between agencies, and immediate and short-term recovery operations
- 7/28/2021 – A joint Tabletop Exercise was conducted with SAWS and CPS Energy
    - The purpose of the exercise was to practice interagency communication during a simulated emergency event sequence scenario
- CPS Energy will host two TEEX training sessions a year and will include SAWS, CoSA, BCOEM, and other local governments
- Staff meets with CoSA, SAWS, and others monthly to discuss the CEP recommendations and how to proceed forward

IMPLEMENTATION TIMELINE

- These types of training will be held annually

MILESTONES

Milestone	Target Date	Status / Comment
Conduct Joint Training Sessions	Quarterly	
Joint Training Sessions Lessons Learned Follow-up	1 month after	
Conduct assessment of communications and working relationship growth between CoSA SAWS and other local governments	Bi-annual	
Update Business Continuity Plan based on findings	45 days after	

DELIVERABLES

Deliverable	Target Date	Owner
Provide feedback on Joint Training Sessions and share training documents	Quarterly	CoSA EOC
Documented Lessons Learned	1 month after	CoSA EOC
Updated Business Continuity Plan	1 month	CPS Energy

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
William McCarson	Business Continuity	120
Blaize Skocny	Incident Response & Business Continuity	80
GridEx Planners (15 employees)	Support	20

BUDGET

- GridEx - $9,000

METRICS

- Better communication between all parties and an improved response to events effecting our customers
- Tracking of Lessons Learned and making those corrections in our plans

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/3/2021
Executive Sponsor	Shanna Ramirez	11/12/2021
Co-Executive Sponsor	Paul Barham	11/12/2021
Response Lead	Garrick Williams	11/29/2021
Business Area POC	Josh Dean	11/12/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR EOC 11

Work with the City of San Antonio (CoSA) to enhance city-wide cross-department and cross-discipline emergency response training.

PLAN OVERVIEW

Executive Sponsor	**Shanna Ramirez**
Name of Action / Project	CEPR EOC 11
Co-executive Sponsor	**Paul Barham**
Point of Contact	Josh Dean
Action Plan Development Team	Melissa Gutierrez, Blaize Skocny, William McCarson

OBJECTIVE

CPS Energy will work with the city Emergency Operations Center (EOC), SAWS, and Bexar County Office of Emergency Management (BCOEM) to plan disaster scenarios and then participate with the San Antonio Office of Emergency Management (SAOEM) in exercises addressing those scenarios. We have already planned and outlined the training for the remainder of this year and will add these scenarios to future training.

RECOMMENDATION CATEGORY / DESCRIPTION

BENEFITS / REWARDS

- Determine if response plans are effective
- Identify flaws or gaps in the organization's response and adjust
- Ensuring documentation of response plans
- Determine roles within different entities
- Update Business Continuity Plans based on findings

RISKS

- Covid-19 restrictions could hinder timelines and effectiveness
- Confidential information could be exposed
- Funding and/or resources may not be appropriate for critical needs
- High priority activities may be in conflict, jeopardizing the ability to complete critical tasks
- Changes in personnel may impact the completion of critical activities
- CPS Energy plans may not be in alignment with the plans of other entities

DETAILS

ACTION PLAN / PROJECT DETAILS

- CPS Energy will host two Texas A&M Engineering Extension Service (TEEX) training sessions a year and will include SAWS, CoSA, BCOEM, and other local governments
- CPS Energy will include SAWS, CoSA, BCOEM, and other local governments in CPS Energy led training such as GridEx and internal CPS Energy training
- CPS Energy Business Continuity and Emergency Management will meet with SAWS Emergency Management, CoSA EOC, BCOEM, and other local governments once a month to check in and help make sure findings from the CEP that involve CPS Energy, SAWS, and CoSA are being followed up on

EXECUTION

ASSOCIATED ROADMAP

- 5/11/2021 – The Texas Torrent: 2021 Alamo Area Community Flood Resilience tabletop exercise focuses on pre-incident and information sharing protocols; incident response protocols; collaboration and coordination between public and private sector partners; public messaging and media relations; and immediate, short-term, and long-term recovery operations
    - Participants included CPS Energy, BCOEM, SAOEM, San Antonio Fire Department (SAFD), San Antonio Police Department (SAPD), San Antonio River Authority (SARA), and many more
- 6/02/2021 – The SAOEM, in conjunction with the San Antonio Metropolitan Health District (SAMHD), BCOEM, CPS Energy, and SAWS, participated in an Extreme Heat Tabletop Exercise
    - This exercise provided the opportunity for stakeholders to engage in open and collaborative discussions regarding pre-incident information sharing, incident response protocol, a collaboration between agencies, and immediate and short-term recovery operations
- 7/28/2021 – A joint Tabletop Exercise was conducted with SAWS and CPS Energy
    - The purpose of the exercise was to practice interagency communication during a simulated emergency event sequence scenario
- Staff meets with CoSA, SAWS, BCOEM, and others monthly to discuss the CEP recommendations and how to proceed forward

IMPLEMENTATION TIMELINE

- These types of training will be repeated annually

MILESTONES

Milestone	Target Date	Status / Comment
Conduct & track Joint Training Sessions	Quarterly	
Joint Training Sessions Lessons Learned Follow-up	1 month after	
Conduct assessment of communications and working relationship growth between CoSA, SAWS, BCOEM, and other local governments	Bi-annual	
Conduct Annual training	Annually	

DELIVERABLES

Deliverable	Target Date	Owner
Provide feedback on Joint Training Sessions and share training documents	Annually	CoSA EOC
Documented Lessons Learned	1 month after	CoSA EOC
Updated Business Continuity Plan	1 month	CPS Energy

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
William McCarson	Business Continuity	40
Blaize Skocny	Incident Response & Business Continuity	40

BUDGET

- Annual Joint Training Meeting - $2,400

METRICS

- Better communication between all parties and an improved response to events affecting our customers
- Tracking of Lessons Learned and corrected in business continuity plans

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/3/2021
Executive Sponsor	Shanna Ramirez	11/12/2021
Co-Executive Sponsor	Paul Barham	11/12/2021
Response Lead	Garrick Williams	11/29/2021
Business Area POC	Josh Dean	11/12/2021

CEPR EOC 12 – COSA ANNUAL TABLETOP EXERCISE

Work with the City of San Antonio (CoSA) to create an annual emergency response table top exercise that includes elected officials, executive leadership for the City, County and Utilities.

PLAN OVERVIEW

Executive Sponsor	**Shanna Ramirez**
Name of Action/Project	CEPR EOC 12 – CoSA Annual Tabletop Exercise
Co-executive Sponsor	**Paul Barham**
Point of Contact	Josh Dean
Action Plan Development Team	Blaize Skocny, William McCarson, Melissa Gutierrez

OBJECTIVE

CPS Energy will work with the city Emergency Operations Center (EOC), SAWS, and Bexar County Office of Emergency Management (BCOEM) to plan disaster scenarios and then participate with San Antonio Office of Emergency Management (SAOEM) and EOC in exercises addressing those scenarios. We will then exercise those scenarios. We have already planned and outlined the training for the remainder of this year and will add these scenarios to future training.

RECOMMENDATION CATEGORY/DESCRIPTION

REWARDS

- Encourage and improve your team's critical thinking abilities in realistic event scenarios
- Coordinate the right people and organizations to assist in an emergency, within and outside organizations
- Allows interactive communication between emergency management staff in a collaborative
- Increase awareness and understanding of threats
- Update Business Continuity Plans based on findings
- Ensures elected officials and their staff understand actions taken during emergencies

RISKS

- Covid-19 restrictions could hinder timelines and effectiveness
- Confidential information could be exposed
- Funding and/or resources may not be appropriate for critical needs
- High priority activities may be in conflict, jeopardizing the ability to complete critical tasks
- Changes in personnel may impact the completion of critical activities
- Risk of not addressing an event that could occur

DETAILS

ACTION PLAN / PROJECT DETAILS

- CPS Energy will host two Texas A&M Engineering Extension Service (TEEX) training sessions a year and will include SAWS, CoSA, BCOEM, elected officials, and other local governments
- CPS Energy will include SAWS, CoSA, BCOEM, elected officials, and other local governments in CPS Energy led training such as GridEx VI and internal CPS Energy training
- CPS Energy Business Continuity and Emergency Management will meet with SAWS Emergency Management, CoSA EOC, BCOEM, and other local governments once a month to check in and help make sure findings from the CEP that involve CPS Energy, SAWS, CoSA, and BCOEM are being followed up on

EXECUTION

ASSOCIATED ROADMAP

- CPS Energy will host two TEEX training sessions a year and will include SAWS, CoSA, BCOEM, elected offcials, and other local governments
- Staff meets with CoSA, SAWS, Texas Division of Emergency Management (TDEM), BCOEM, and others monthly to discuss the CEP recommendations and how to proceed forward

IMPLEMENTATION TIMELINE

- These types of training will be repeated annually

MILESTONES

Milestone	Target Date	Status / Comment
Conduct & track Joint Training Sessions	Quarterly	
Joint Training Sessions Lessons Learned Follow-up	1 month after	
Conduct assessment of communications and working relationship growth between CoSA, SAWS, BCOEM, elected officials, and other local governments	Bi-annual	
Conduct Annual training	Annually	

DELIVERABLES

Deliverable	Target Date	Owner
Provide feedback on Joint Training Sessions and share training documents	Annually	CoSA EOC
Documented Lessons Learned	1 month after	CoSA EOC
Updated Business Continuity Plan	1 month	CPS Energy

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
William McCarson	Business Continuity	40
Blaize Skocny	Incident Response & Business Continuity	40

BUDGET

- Annual Joint Training Meeting – $2,400

METRICS

- Better communication between all parties and an improved response to events affecting our customers
- Tracking of Lessons Learned and corrected in business continuity plan

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/9/2021
Executive Sponsor	Shanna Ramirez	11/5/2021
Co-Executive Sponsor	Paul Barham	11/5/2021
Response Lead	Garrick Williams	11/18/2021
Business Area POC	Joshua Dean	11/5/2021

Paul S. Barham
Chief Grid Optimization & Resiliency Officer (CGORO)

November 30, 2021

Councilman John Courage - Chairman
City of San Antonio
Municipal Utilities Committee (MUC)

RE: CoSA CEP Recommendation #EOC 13 – Adjust the relationship between the City & CPS Energy

Dear MUC Chairman Courage,

In response to the recommendations outlined in the Committee on Emergency Preparedness (CEP) Report, specifically regarding "**adjust the relationship with CPS Energy that provides, during certain contingencies, authority for CoSA to exercise effective command and control"**, we provide the following proposed approach.

EOC 13 – Adjust the relationship between the City & CPS Energy – The CEP recommendation describes that the City's Emergency Operations Center (EOC) "…lacked the authority to direct the public utilities to provide the necessary information that would have facilitated EOC's command and control responsibilities" (page 31). The proposed approach is to improve the relationship between the City's EOC and CPS Energy such that the City has the information needed both prior to and during an event to support the EOC's planning and coordination activities.

Improved collaboration between CPS Energy and the City's EOC in advance of an event can enable more informed decisions during contingency planning. For example, based on critical circuit information, the decision on where to locate warming centers can be made in advance of the winter season to enable the City's EOC to more effectively deploy resources during a contingency event.

Following the events of Winter Storm Uri, CPS Energy's lessons learned revealed an opportunity to enhance communications between CPS Energy and the City's EOC. Melissa Gutierrez, Director Emergency Operations Planning & Coordination, is tasked with the decision-making authorities which provide executive level presence during emergency operations. Melissa has also taken the necessary steps to reinforce CPS Energy's commitment to the community through a more proactive communication strategy with operational counterparts at the City's EOC, Bexar County, & SAWS. Additionally, we are also staffing Communications professionals at the City's EOC during the event to ensure consistent and seamless communication between emergency organizations throughout the event.

This year, CPS Energy has collaborated with the City's EOC on multiple initiatives including the development and execution of two disaster scenario tabletop exercises, identification of warming and cooling centers, and development of an operational readiness matrix. At the end of September, CPS Energy participated in a severe weather tabletop exercise hosted by the City's EOC and in partnership with the Texas A&M Engineering Extension Service (TEEX).

Continued collaboration with the City's EOC, through education, joint planning, and emergency training can enable a greater understanding of operational and community impacts during contingency events. Additionally, having a CPS Energy representative physically located at the City's EOC when mobilized in response to a crisis can enable real-time information sharing about circuit outages that may impact city facilities. Understanding outage impacts in advance of an event and obtaining the necessary information during an event can enable the alignment of roles and expectations that impact the community in a beneficial way.

Please let us know if you have any questions or require additional information.

Sincerely,

Paul

PSB:gtw

Copy City of San Antonio:

Chief Financial Officer & Supervisor of Public Utilities, B. Gorzell
City Attorney, A. Segovia/T. Beaulieu

Copy CPS Energy:

Board Members
Interim President & CEO, R. Garza
Senior Chiefs
Response Lead, G. Williams
Board Relations
Citizens Advisory Committee
Rate Advisory Committee

Paul S. Barham
Chief Grid Optimization & Resiliency Officer (CGORO)

November 30, 2021

Councilman John Courage - Chairman
City of San Antonio
Municipal Utilities Committee (MUC)

RE: CoSA CEP Recommendation #EOC 14 – CPS Energy's load-shedding decisions

Dear MUC Chairman Courage,

In response to the recommendations outlined in the Committee on Emergency Preparedness (CEP) Report, specifically regarding "**CPS Energy's load-shedding decisions should be made in concert with emergency managers and city leaders"**, we provide the following proposed approach.

EOC 14 – CPS Energy's load-shedding decisions – The CEP report describes that if, "…load-shedding decisions were done in concert with emergency managers and city leaders, decisions about where to locate warming centers could have been based on an awareness of the critical circuits that were least likely to lose power" (page 31).

During Winter Storm Uri, the process of Firm Load Shed was executed by a team of trained operators who are certified by the North American Electric Reliability Corporation (NERC) to handle emergencies of the bulk power system. Firm Load Shed, or controlled outages, are directed by the Electric Reliability Council of Texas (ERCOT) to rapidly reduce electric demand and prevent a complete blackout of the Texas grid. They are used as a last resort to balance generation and demand by supporting operating reserves and maintaining system frequency. The CPS Energy team has the expertise and knowledge gained through years of certification training and operational experience to operate the bulk electric power system effectively.

The proposed approach improves collaboration between CPS Energy and the City's EOC in advance of an event. Before a potential event, decisions on where to locate warming centers and other critical support services can be made. Collaboration between CPS Energy and the City's EOC in advance of an event enables a greater understanding of the operational impacts during an event which directly improves the mobilization and support of critical resources. Sharing information about circuits and load shed during planning exercises can facilitate decisions on where to locate warming centers should an event occur.

The CEP report describes, "...load-shedding could have been scheduled in a way that, combined with specific public messaging to affected areas, allowed for proper planning by affected customers" (page 31). It is important to note that CPS Energy does <u>not</u> schedule load-shed. The amount of load in megawatts (MWs) to be shed and the event duration is the operating responsibility of ERCOT. Once CPS Energy is notified by ERCOT of a need to shed load, CPS Energy must comply within 30 minutes and shed the directed amount of load.

Improved collaboration with the City's EOC through education, joint planning, and emergency training scenarios enables a greater understanding of operational limitations and community impacts during energy emergency events. Understanding these impacts and having established communication channels in place can significantly improve the collaborative development of public messaging and support during an event. To this end, we have held multiple sessions with City leadership to educate them on how load shed works and we are offering the same opportunity to the Southwest Texas Regional Advisory Council (STRAC).

Please let us know if you have any questions or require additional information.

Sincerely,

Paul

PSB:gtw

Copy City of San Antonio:
Chief Financial Officer & Supervisor of Public Utilities, B. Gorzell
City Attorney, A. Segovia/T. Beaulieu

Copy CPS Energy:
Board Members
Interim President & CEO, R. Garza
Senior Chiefs
Response Lead, G. Williams
Board Relations
Citizens Advisory Committee
Rate Advisory Committee

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR EOC 20

City 311 and CPS/SAWS Customer Service Call Centers should develop protocols to enhance the customer experience for the community including extended hours.

PLAN OVERVIEW

Executive Sponsor	**DeAnna Hardwick**
Name of Action/Project	CEPR EOC 20
Co-executive Sponsor	
Point of Contact	Andrew Hush
Action Plan Development Team	Christen Waggoner, Andrew Hush, Demetrius Payton, DeAnna Hardwick

OBJECTIVE

City 311 and CPS/SAWS Customer Service Call Centers will work together to develop protocols to enhance the customer experience and improve communication between CoSA, SAWS, and CPS Energy in support of the community, including regular touch base meetings to share initiatives and best practices.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

- Coordinate the right people and organizations to assist with customer support during emergencies
- Encourages interactive communication between emergency management staff
- Awareness of business practices across organizations, for better customer experience and support
- Create a collaborative relationship to share best practices and shared customer solutions

RISKS

- Covid-19 restrictions could hinder timelines and effectiveness if in person meetings are required instead of virtual sessions in the future
- We need to ensure when solutioning any customer experience enhancements we do not release any confidential customer information
- Funding and/or resources may not be adequate for critical needs
- Changes in personnel may impact the completion of critical activities

DETAILS

ACTION PLAN / PROJECT DETAILS

- 24/7 Operations:
  - CPS Energy call center is a 24/7 operation for emergency calls, with available staff to answer & support customers
  - CPS Energy has offered flex Customer Service Walk-In Center hours during the pandemic as well as extending hours to provide support for American Rescue Plan Act (ARPA)
    - We normally close the centers during weather emergencies
  - CPS Energy uses an overflow provider that does have the most up to date outage information & that we now update the system so that the customer hears the same details shared in the stakeholder messages.
    - An option is available in the overflow system to speak with our representative
  - Meet with 311 & SAWS to discuss how our systems work and have ongoing conversations to identify any additional areas of improvement
  - Add leaders from SAWS & 311 Customer Service teams to our stakeholder engagement texts/message

EXECUTION

ASSOCIATED ROADMAP

- Meet with City 311 & SAWS to discuss CEP recommendations and develop plan to collaborate
- Ensure all parties are aware of current customer service channels, protocols, and emergency management methods:
  - Call Center:
    - 210-353-HELP (4357) is for emergency outage reporting exclusively 24/7
    - 210-353-2222, 210-353-3333 includes emergency outage reporting and self-service options
    - Customer Service support is 7:00 am – 7:00 pm Mon-Fri and 8:00 am – 1:00 pm Sat. Self-Service & outage reporting is 24/7
    - High Volume Answering Service - Activated when large volumes of calls come into the contact center, due to an outage
      - Customers are instructed to report their outage via Interactive Voice Recording (IVR) and there is an option in the to get to our representative
    - Use of 3rd party outsourced call centers for business continuity
  - Customer Service Walk-In Centers:
    - Customer Service Centers Hours: Monday – Friday, 7:45 AM – 5:00 PM, except holidays

- Starting on Wednesday 11/17, Customer service hours were temporarily extended to 6:45 PM on Wednesdays only

- Establish regular touch base meetings to stay connected and enhance the customer experience
- Assess technology approach & identify needs for call routing changes, if any

IMPLEMENTATION TIMELINE

- Monthly collaboration meetings began 09/16/21

MILESTONES

Milestone	Target Date	Status/ Comment
Collaboration Meetings	Monthly	Began 09/16/21
New Initiative Briefings	Quarterly	
Conduct assessment of communications and working relationship growth between CoSA, SAWS, & CPS Energy	Bi-annual	
Participate in the 311 RFP Customer Service Answering, Monitoring, Training Services (22-006, 6100014610)	01/04/22	Christen Waggoner will sit on RFP panel.

DELIVERABLES

Deliverable	Target Date	Owner
Complete technical assessment of call volumes and routing from 311 to CPS Energy. Assessment determined that existing process and average speed of answer times meet expectations and the High Volume Answering Service supports higher volumes via IVR/ Energy Advisor during emergencies. No changes made. Item closed 10/27/21	11/01/21	Demetrius Payton, Christen Waggoner
Executive updates on projects and initiatives	Monthly/as needed	Business Area POC
Progress assessment	Bi-annual	Business Area POC

BUDGET

- N/A, Future identified initiatives will be budgeted on an as-needed basis.

METRICS

- Better communication between all parties, measured by number of regular monthly meetings held between COSA, SAWS & CPS-E
  - Defined point of contacts with escalation paths for each group, with monthly confirmation during meetings that all established members, escalations paths and contact details are up to date
- Further metrics will be built based on any future identified initiatives designed to enhance customer experience

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Andrew Hush	Interim Director, Customer Service	40
Christen Waggoner	Interim VP, Customer Experience Ops	40

APPROVAL

Title	Name	Date
Interim CEO	Rudy Garza	12/22/2021
Executive Sponsor	DeAnna Hardwick	10/05/2021
Co-Executive Sponsor	Christen Waggoner	09/16/2021
Business Area POC	Andrew Hush	09/16/2021
Response Lead	Garrick Williams	12/20/2021

CEP EOC 23 – LOAD SHED COMMUNICATION

CEP Recommendation: The impact of CPS rotating outages should be clearly communicated and coordinated with COSA and SAWS to determine operational/service impacts more comprehensively.

The planned action is to improve collaboration with the City's EOC and SAWS through education, joint planning, and emergency training scenarios. Enhanced collaboration can enable a greater understanding of operational and service impacts during energy emergency events.

PLAN OVERVIEW

Business Unit/Area Name	Paul Barham
Name of Action/Project	CEPR EOC 23 – Load Shed Communication
Co-executive Sponsor	Melissa Sorola
Point of Contact	Rick Maldonado
Action Plan Development Team	Zachary Lyle, Melissa Gutierrez

OBJECTIVE

The objective is to increase communication and coordination with the City's EOC and SAWS to enable a more comprehensive understanding of the operational impacts during rotating outages.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

Improved collaboration between CPS Energy and the City's EOC & SAWS in advance of an event can enable more informed decisions during contingency planning. For example, based on critical circuit information, the decision on where to locate warming centers can be made in advance of the winter season to enable the City's EOC to more effectively deploy resources during a contingency event.

RISKS

The risk of implementing this recommendation is that CPS Energy's confidential and proprietary information about exempt circuits will be shared with the City's EOC and

SAWS. This can result in CPS Energy's confidential and proprietary information being shared in the public and compromising CPS Energy's ability to keep its confidential and proprietary information secure.

DETAILS

ACTION PLAN / PROJECT DETAILS

- Engage the City's EOC and SAWS in education, joint planning, and emergency training scenarios
- Provide an overview of load shed (controlled outages) to the City's EOC and SAWS
- The risk of implementing this recommendation has been mitigated by establishing non-disclosure agreements between CPS Energy, the City's EOC and SAWS
  - Prior to sharing information with the City's EOC and SAWS, follow internal controls in place to ensure the integrity of the shared data

EXECUTION

ASSOCIATED ROADMAP

- Engage the City's EOC & SAWS in education, joint planning, and emergency training scenarios
- Engage the City's EOC & SAWS to provide an overview of load shed
- Provide System Operations executive contact (Director Emergency Ops Planning & Coordination) at EOC in all emergency events to support real time system information and coordination

IMPLEMENTATION TIMELINE

Implement enhanced collaboration activities, for education and joint training, in advance of summer season and winter season.

MILESTONES

Milestone	Target Date	Status / Comment
Participated in the development and tabletop exercise for a severe flood scenario hosted by the San Antonio Office of Emergency Management (SAOEM) in partnership with the Cybersecurity and Infrastructure Security Agency (CISA)	May 2021	Complete
Created Director Emergency Ops Planning and Coordination position in Customer Reliability to	May 2021	Complete

provide a direct operational contact point for coordination with EOC, SAWS, Bexar County Office of Emergency Management and other emergency operation stakeholders		
Participated in the development & tabletop exercise for a severe heat scenario hosted SAEOM	June 2021	Complete
Engaged SAWS in Emergency Operations & Load Shed Training	July 2021	Complete
Participated in a tabletop exercise with SAWS for a controlled outage scenario facilitated by Black & Veatch	July 2021	Complete
Discussed CPS Energy & SAWS roles in emergency operations hosted by SAOEM	August 2021	Complete
Engaged with SAOEM, SAWS, & other partner agencies for an emergency operations table top exercise facilitated by the Texas A&M Engineering Extension Service (TEEX)	September 2021	Complete
Coordinated with SAWS to identify their critical water and wastewater facilities and develop a plan for load reduction during energy emergencies	October 2021	Complete
Engaged Deputy City Manager and SAOEM Chief in Emergency Operations & Load Shed Training	October 2021	Complete
Engaged SAFD Chiefs in Emergency Operations & Load Shed Training	October 2021	Complete
Presented Load Shed Overview & Winter Preparedness Update to Southwest Texas Regional Advisory Council	October 2021	Complete
Engaged SAWS (& Arcadis) in an Overview on Load Shed and Winter Preparedness	November 2021	Complete
Revisit internal A-03 Interoperability Communication procedure	November 2021	Complete
Establish monthly meetings with SAWS & SAOEM to discuss emergency preparation activities, tabletop exercises, & training	Recurring Monthly	Complete

DELIVERABLES

Deliverable	Target Date	Owner
Training presentations and materials developed and shared during annual intra-agency emergency response training.	Recurring Annually	EOC

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Zachary Lyle		N/A
Melissa Gutierrez		N/A

BUDGET

Internal Labor captured in existing budget.

METRICS

Metric: Total Count of Collaborative Sessions

Target: Total count of Collaborative Sessions Post Uri is greater than the total count of Collaborative Sessions Pre Uri

Target achieved. Total count of collaborative sessions Post Uri is 25+. Total count of collaborative sessions Pre Uri is approximately 8 (Joint Base San Antonio Geomagnetic Disturbance (GMD) tabletop & Hazard Mitigation Plan update meetings). The variance is an increase of 17+.

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/17/2021
Executive Sponsor	Paul Barham	11/22/2021
Co-Executive Sponsor	Melissa Sorola	11/22/2021
Response Lead	Garrick Williams	12/14/2021
Business Area POC	Rick Maldonado	11/22/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR EOC 24 – OUTAGE IMPACT (OPERATIONAL DASHBOARD)

The CoSA EOC should identify a situational awareness platform that can display evolving information remotely from operational teams to leadership.

The project team, being led by Jatinder Singh (VP of Digital and Data Transformation) will gain an enterprise-wide understanding of business needs and internal stakeholder use cases to support the development of a future situational awareness and communications platform to improve communications and response to stakeholders during critical outage, load shed or resiliency events.

The target solution is herein referred to as the '**Situational Awareness Platform'** and next steps with outcomes to achieve are outlined under the ACTION PLAN/PROJECT DETAILS.

NOTE: The Situational Awareness Platform and the associated action plan outlined below is focused on supporting the internal needs of CPS Energy only. We will be on standby to support the EOC as plans develop to deliver a Situational Awareness Platform for the EOC's use.

PLAN OVERVIEW

Executive Sponsor	**Vivian Bouet**
Name of Action/Project	Situational Awareness Platform
Co-executive Sponsor	Richard Medina
Point of Contact	Paula Oles
Action Plan Development Team	Jatinder Singh, Rolando Vega, Eddie Kirby, Paula Oles *(input support from other CEP Action Plan owners and Business Stakeholders: Melissa Sorola, Melissa Gutierrez, Rick Maldonado, DeAnna Hardwick, Kathleen Garcia, Yvonne Pelayo, and others that are currently being identified)*

OBJECTIVE

The CPS Energy Situational Awareness platform will deliver a technology solution to centralize inputs, data flows and critical operational and weather information for CPS Energy employees in order to facilitate real time, actionable insights for decision-making and stakeholder communications during critical outage, load shed or resiliency situations.

RECOMMENDATION CATEGORY / DESCRIPTION

BENEFITS / REWARDS

1. Centralization of Information for Proactive Response:
    a. Integrated dataflows of related sources from SCADA/OT systems, GIS systems, KUBRA and other likely inputs such as real time video, weather applications, incident management and security tools, and others to be identified to monitor key operations and surface critical information for decision making and stakeholder communication during an outage event.
    b. Centralization of key operational information critical to anticipate and respond to service and operational disruptions and elevate early visibility of impact to customers.
    c. Remote access to evolving information easily consumable for operational teams to leadership.
2. Consistent Communications:
    a. Single source of information to monitor and share information to pro-actively plan and communicate audience appropriate and consistent response.

RISKS

1. Our current AMI and OMS technology systems may have data exchange or other technical gaps which do not support key identified business and situational use cases.
2. Multiple and disparate system and data sources may require increased customization for data integration and centralization (e.g. ++APIs) and greater technical complexity/cost to adequately solve for all business and situational use cases.
3. Enterprise Security concerns and NERC-CIP compliant challenges may need to be addressed if a Cloud based utility domain solution is selected.
4. Data extracted from critical systems may not be complete and/or inaccurate posing data integrity risks that must have a data review and quality control plan to mitigate.

DETAILS

ACTION PLAN / PROJECT DETAILS

1. We will continue to reach out to EOC partners to understand their plans for the Situational Awareness Platform per the CEP EOC 24 recommendation, so that we are able to support them as needed.
2. Our internal action plan will outline next steps for launch of a Situational Awareness Platform in which dataflows and key inputs during an outage weather event are centralized for stakeholder monitoring, visibility and response. The platform will provide actionable insights for decision making and will support audience appropriate communications for those stakeholders impacted by an outage event.
   A. Stakeholders have been identified as:
      i. Internal CPS Energy response personnel – Customer Service, Customer Engagement, System Operations, Corporate Communications, Grid Operations, Government Relations and all respective enterprise leadership stakeholders
      ii. Managed accounts and other non-managed residential and commercial CPS Energy accounts
      iii. High visibility circuit accounts

   It is an important distinction to note that access, hosting and maintenance of the platform will be supported for secure use by CPS Energy personnel only but will aide CPS Energy with the actionable insights needed during critical events for external parties.

3. To mitigate data integrity risks as noted in the RISKS section, a data validation and quality control plan documented through system and applicable data test cases will be formalized, reviewed for completeness and executed.

4. In order to ensure that CPS Energy's Situational Awareness platform benefits from the insights in how the energy and utility industry is addressing a solution with best practice design and technologies, the project team will bring onboard a technical business analyst from our trusted utility domain partner and advisor, Black & Veatch (B&V).

5. To support coverage of requirements necessary for the Situational Awareness Platform, the following activities will be led by the B&V technical business analyst to execute the following:

   A. Conduct a series of (link to: stakeholder meetings) and with other CEP action plan owners to understand their specific related use cases. These identified action plan owners hold MUC recommendations likely dependent on similar technology to support communication outcomes achievable through the Situational Awareness Platform. The goal of the work defined within this action plan is to ensure we are solving to a common solution to achieve the outcomes for multiple and similar MUC recommendations.

   B. Perform System Operation site visits to observe current operational procedures during non-outage periods (e.g., 'Blue Sky Day') and during more extreme weather conditions in which outage events are anticipated.

   Outcomes of the interviews and workshop will culminate a prioritized list of use cases that the Situational Awareness Platform must support going forward.

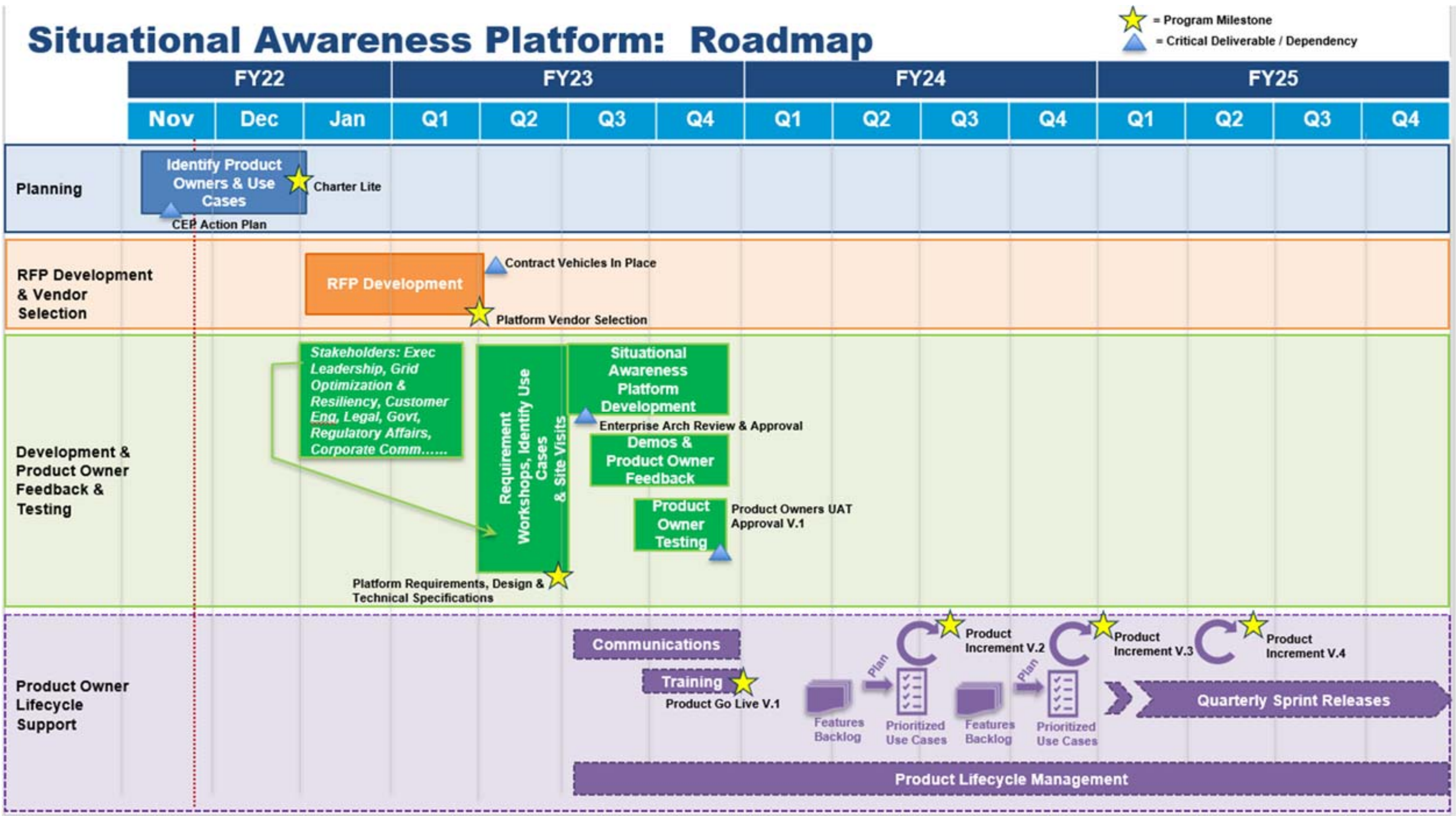
6. A Project Charter Lite will be developed to inform details for an RFP (or other SoW engagement) to identify a technical solution partner.
   A. The technical solution implementation will likely require a combination of resources from the Technical Solution partner as well as a cross functional product support team of CPS Energy employees.
   B. The product team will roll out Situational Awareness functionality based on the stakeholder use cases prioritized and iterate with increased functionality through updates to support secondary and tertiary use cases over quarterly release sprints.
   C. The technical solution will have a business product owner (likely the System Operations Executive) and a technical product owner (likely a Digital/Data Executive) who will co-lead the development and rollout of the various use cases.

7. The product team, co-led by the Business Product Owner and Technical Product Owner, will develop an action plan to roll out the Situational Awareness plan per below timeline.

EXECUTION

ASSOCIATED ROADMAP

SOURCE: ***[CEPR_EOC 24_ROADMAP.PPTX]***



IMPLEMENTATION TIMELINE

See above

MILESTONES

Milestone Summary	Target Date	What Has Been Achieved
Project Charter Lite Approved	January 2022	Sr. Chief's approval of proposed solution, stakeholder use cases and implementation plan
Technical Solution Identified (via RFP)	Q1 FY23	Platform or solution vendor identified through RFP award or appropriate SOW engagement
Requirements, Design & Technical Specifications Approved	Q2 FY23	Stakeholder and product owner workshops and site visits conducted to define requirements and technical specs to deliver support of stakeholder use cases.
Situational Awareness Platform v1.0 Launch	Q4 FY23	Platform Go Live addressing initial prioritized use cases and supporting plans for quarterly product releases to address a prioritized features backlog.

DELIVERABLES

Deliverables	Target Date
Project Charter Lite	January 2022
Prioritized Stakeholder Use Cases	Q1 FY23
Platform Requirements, Design & Technical Specifications	Q2 FY23
Go Live Launch, Training & Communication Plans	Q4 FY23

RESOURCES

PROJECT / ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Paula Oles	Program Manager, Digital and Data Transformation Portfolio	300 (5 hrs/wk x 15 months)
Melissa Gutierrez	System Operations, Business Product Owner	600 (10 hrs/wk x 15 months)
TBD	Digital/Data, Product Owner	2,400 (160 hrs/wk x 15 months)
TBD	Data Integration / Engineering (3 Resources)	7,200 (3 x 40 hrs/wk x 15 months)
TBD	Testers (2 Resources)	4,800 2 x 40 hrs/wk x 15
Business Partners (Key Stakeholders)	Corporate Communications, Customer Engagement, Legal & Government Affairs, Key Account Management, Community Engagement, Grid Operations, etc.	960 8 x 2 hrs/wk x 15 months

*Several other technical resources from technical partner and change management will be part of the team. Their estimated resource hours will be developed post the technical solution identification.

BUDGET

Per Apex FY23 budget load:

	CAPITAL				
Cost Element	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**
Purchased Materials	2,691,000	4,584,000	2,484,000	2,484,000	2,484,000
Capital Total	2,691,000	4,584,000	2,484,000	2,484,000	2,484,000
	O&M				
Cost Element	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**
Outside Services	900,000	120,000	50,000	50,000	50,000
O&M Total	900,000	120,000	50,000	50,000	50,000
Total Budget	**3,591,000**	**4,704,000**	**2,534,000**	**2,534,000**	**2,534,000**

METRICS

Metric	Expectations
Improved proactive customer communications during load shed or critical outage event.	• Leveraging a baseline Customer Satisfaction Score (CSAT) assessed quarterly through a formal customer survey, post launch of the Situational Awareness Platform and following an outage event, we expect an improved CSAT rating at the next quarterly assessment for the below measurements: o CPS Energy's ability to **effectively communicate** during outage events. • Improved **brand perception** by respondents of CPS Energy's communication and response ability during outage events.

APPROVAL

Title	Name	Target Date	Approval Date
Interim President & CEO	Rudy Garza	01/30/2022	12/7/2021
Executive Sponsor	Vivian Bouet	01/20/2022	11/22/2021
Co-Executive Sponsor	Richard Medina	01/20/2022	11/22/2021
CEP Action Plan PoC	Jatinder Singh	01/15/2022	11/22/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR SAWS 2 - SAWS LOAD REDUCTION PLAN

In conjunction with CPS Energy, identify and place infrastructure required to maintain water and sewer operations to critical facilities on uninterruptible circuits in order to avoid service interruptions.

PLAN OVERVIEW

Executive Sponsor	**Paul Barham**
Name of Action/Project	CEPR SAWS 2 – SAWS Load Reduction Plan
Co-executive Sponsor	**Richard Medina**
Point of Contact	George Tamez and Melissa Gutierrez
Action Plan Development Team	Zachry Lyle, Clayton Kruse, Joe Jones, Melissa Gutierrez, James Trevino and George Tamez

OBJECTIVE

The objective is to develop an operational protocol between CPS Energy and SAWS operations centers to enable alignment on infrastructure resources during energy emergencies and provide SAWS with options for improving resiliency and reliability of electric services to their critical facilities in order to determine the best strategy for avoiding service interruptions.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

- Targeting SAWS designated critical facilities for improved resiliency and reliability
- Minimizing the impact to SAWS critical facilities during a controlled outage event
- Providing critical facilities with higher reliability and improved resiliency during extreme weather event

RISKS

- Infrastructure and equipment may have premature end of life failure or be subject to an extended outage due to maintenance or repairs
- Unforeseen obstacles to deploying infrastructure and equipment in the field
- Service availability of electrical infrastructure on critical circuits in order to maintain circuit energization during an extreme event
- Weather related and extreme events may cause outages and service interruptions to distribution circuits

- Only provides a partial solution to select facilities and does not address a grid blackout event

DETAILS

ACTION PLAN / PROJECT DETAILS

Item 1. Coordinate with Managed Accounts to identify SAWS critical facility locations.
Completed.

Item 2. Conduct circuit mapping of SAWS critical facility locations.

Completed.

Item 3. Coordinate with Customer Reliability and Grid Transformation & Planning to identify circuit infrastructure options.

- Planned infrastructure of 8 reclosers to be added to circuits to increase reliability

Completed.

Item 4. Development of a Joint Planning Team (JPT) of SAWS and CPS Energy to develop and deliver a plan to:

- Minimize impacts on the community and the environment by evaluating critical facilities to determine the best strategy for avoiding service interruptions

Completed.

Item 5. Provide SAWS with circuit infrastructure options on their critical facilities to enable their contingency planning for meeting Senate Bill 3 requirements.

Completed.

Item 6. In collaboration with SAWS, draft a Load Reduction Plan.

Completed.

Item 7. Implementation of the SAWS Load Reduction Plan with presentation of the Load Reduction Plan to Executive Management of CPS Energy and SAWS and make modifications as required.

Completed.

EXECUTION

ASSOCIATED ROADMAP

Communication session→ Opportunity analysis→ Provide customer with options

IMPLEMENTATION TIMELINE

Provide SAWS with circuit infrastructure options by December 15, 2021. **Completed.**

MILESTONES

Milestone	Target Date	Status / Comment
Targeted list of critical sites and circuit mapping	9/1/2021	Completed 7/23/2021
Provide circuit infrastructure options to SAWS	10/1/2021	Completed 8/26/2021
Collaborate with SAWS to draft Load Reduction Plan	11/1/2021	Completed 10/4/2021

DELIVERABLES

Deliverable	Target Date	Owner
Development of a collaborative, operational, infrastructure resource protocols within a Load Reduction Plan to enable SAWS to enhance their contingency planning and meet Senate Bill 3 requirements.	Completed 10/4/2021	Melissa Gutierrez, Clayton Kruse and Zach Lyle

RESOURCES

BUDGET

Internal labor is being absorbed by existing departmental budgets and projects already in flight.

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/17/2021
Executive Sponsor	Paul Barham	12/10/2021
Co-Executive Sponsor	Richard Medina	12/10/2021
Response Lead	Garrick Williams	12/14/2021
Business Area POC	George Tamez	12/8/2021
Business Area POC	Melissa Gutierrez	12/8/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR SAWS 3 - SAN ANTONIO WATER SYSTEM GENERATORS

SAWS should coordinate with CPS Energy to determine which locations must have power generators and/or fuel storage for load reduction events and consider shared uses for generators.

PLAN OVERVIEW

Executive Sponsor	**DeAnna Hardwick**
Name of Action/Project	SAWS Critical Sites for Back-Up Generation
Co-executive Sponsor	N/A
Point of Contact	Karma Nilsson
Action Plan Development Team	Clayton Kruse, Rhonda Krisch, Zach Lyle, Melissa Gutierrez

OBJECTIVE

Coordinate with SAWS on the locations they identify that must have power generators and/or fuel storage for load reduction events with consideration for shared uses for generators.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

- Improved relationships and customer satisfaction
- Concerted strategy to protect our community's most critical infrastructure, e.g., Hospitals
- Support SAWS as they work to fulfill their regulatory requirements
- Providing energy information for a community utility and customer to help them to be able to provide service consistently to our community during a major energy event
    - We will provide support to assist SAWS with getting the solution they select through the interconnection and installation process

RISKS

Costs associated with the on-site generation needed to support SAWS requirements associated with SB3 will be a significant investment and is not currently covered in SAWS budget.

SAWS is currently working with Black & Veatch to identify and prioritize their facilities for back-up generation needs.

CPS Energy will support SAWS through the interconnection and installation of their solution. Depending on the solution SAWS selects, CPS Energy may also work with SAWS on identifying and implementing opportunities to sell energy to CPS Energy and/or the market during high energy pricing times.

If SAWS select a solution that requires new natural gas service, it may take some time to implement service at their priority sites. There is a risk that SAWS will most likely go through at least one additional winter and summer without this backup generation in place. SAWS ability to obtain funding and time needed to install the systems may add risk to their obtaining back-up generation.

Current global material supply shortages may further delay implementation for SAWS

DETAILS

ACTION PLAN/PROJECT DETAILS

- Set check-ins with SAWS on project
- Request timeline from SAWS for identifying sites
- Identify SAWS available budget and target number of sites for SAWS
- Provide information on resiliency rate and program
- Set expectations for natural gas availability
- Provide cost and time estimates if needed for natural gas or electric service to sites
- Set expectations for potential effects of global material supply shortages

EXECUTION

ASSOCIATED ROADMAP

Serve as energy expert → provide information → work with SAWS selected vendor

IMPLEMENTATION TIMELINE

Complete site selections and prioritization by December 31, 2021

MILESTONES

Milestone	Target Date	Status/Comments
Select and finalize priority sites for back-up generation	October 2021	Complete
Prioritize major SAWS sites for back-up generation, exempt or load shed status	October 2021	Complete

DELIVERABLES

Deliverable	Target Date	Owner
List of SAWS sites by priority	October 2021	SAWS
List of SAWS sites categorized for exempt or load shed status	October 2021	SAWS

RESOURCES

PROJECT/ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
Karma Nilsson	Business Area POC	20 hours
Account Management	Customer contact	40 hours
Finance	Billing & financial settlement	4-8 hours
Energy Supply & Market Operations	Possible QSE & market connection	4-8 hours
Gas Solutions	Availability, construction estimates	10 hours

BUDGET

CPS Energy Budget – no budget is needed for this CEP recommendation to identify sites. When implementation of back-up generation is complete, we may need to budget for construction and management of SAWS back-up generation solutions. We estimate $50,000 per site (6) for a total of $300,000 should be considered for the upcoming year budget.

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	11/23/2021
Executive Sponsor	DeAnna Hardwick	10/29/2021
Response Lead	Garrick Williams	11/17/2021
Business Area POC	Karma Nilsson	10/29/2021

CEPR SAWS 5 – SAWS JOINT EXERCISES

Support San Antonio Water System (SAWS) in performing routine disaster scenarios with us and with the City of San Antonio's Emergency Operations Center (EOC).

PLAN OVERVIEW

Executive Sponsor	Shanna Ramirez
Name of Action/Project	CEPR SAWS 5 – SAWS Joint Exercises
Co-executive Sponsor	**Paul Barham**
Point of Contact	Josh Dean
Action Plan Development Team	Melissa Gutierrez, Blaize Skocny, William McCarson

OBJECTIVE

Perform disaster recovery scenarios with CPS Energy and the EOC, such as natural disaster and terrorist attack response simulations. In addition to tabletop exercises, conduct in-person field exercises.

RECOMMENDATION CATEGORY/DESCRIPTION

Coordinate with CoSA, San Antonio Office of Emergency Management (SAOEM), SAWS, Bexar County Office of Emergency Management (BCOEM), and CPS Energy training with Texas A&M Engineering Extension Service (TEEX). We began planning the training and tabletop exercise in August. A tabletop exercise was held on 9/28/2021, with COSA, SAWS, Bexar County, and other applicable entities participated. CPS Energy will invite the above entities to join the GridEx. GridEx is a distributed play grid exercise that allows participants to engage remotely, simulates a cyber and physical attack on the North American electricity grid and other critical infrastructure. The planning began in early July.

REWARDS

- Evaluates overall incident preparedness
- Clarifies roles and responsibilities during an incident
- Assess the capabilities of existing resources
- Identify deficiencies in business continuity plans, including technical, planning & procedural
- Update Business Continuity Plans based on findings

RISKS

- Covid-19 restrictions could hinder timelines and effectiveness
- Confidential information could be exposed
- Funding and/or resources may not be appropriate for critical needs
- High priority activities may be in conflict, jeopardizing the ability to complete critical tasks
- Changes in personnel may impact the completion of critical activities

DETAILS

ACTION PLAN / PROJECT DETAILS

- CPS Energy will host two TEEX training sessions a year and will include SAWS, COSA, BCOEM, elected officials, and other local governments
- CPS Energy will include SAWS, COSA, BCOEM, elected officials, and other local governments in CPS Energy led training such as GridEx and internal CPS Energy training
- CPS Energy Business Continuity and Emergency Management will meet with SAWS Emergency Management, COSA EOC, BCOEM, and other local governments once a month to check in and help make sure findings from the CEP that involve CPS Energy, SAWS, and COSA are being followed up on

EXECUTION

ASSOCIATED ROADMAP

- 5/11/2021 – The Texas Torrent: 2021 Alamo Area Community Flood Resilience tabletop exercise focuses on pre-incident and information sharing protocols, incident response protocols, collaboration and coordination between public and private sector partners; public messaging and media relations; and immediate, short-term, and long-term recovery operations
  - Participants included CPS Energy, BCOEM, SAOEM, SAFD, SAPD, San Antonio River Authority (SARA), and many others
- 7/28/2021 – A joint Tabletop Exercise was conducted with SAWS and CPS Energy
  - The purpose of the exercise was to practice interagency communication during a simulated emergency event sequence scenario
- 6/02/2021 – The SAOEM, in conjunction with the San Antonio Metropolitan Health District (SAMHD), BCOEM, CPS Energy, and SAWS, participated in an Extreme Heat Tabletop Exercise
  - This exercise provided the opportunity for stakeholders to engage in open and collaborative discussions regarding pre-incident information sharing, incident response protocol, a collaboration between agencies, and immediate and short-term recovery operations
- Staff meets with COSA, SAWS, and others monthly to discuss the CEP recommendations and how to proceed forward

IMPLEMENTATION TIMELINE

- Joint training exercises will be repeated annually

MILESTONES

Milestone	Target Date	Status/ Comment
Conduct Joint Training Sessions	Annually	
Joint Training Sessions Lessons Learned Follow-up	1 month after	
Conduct assessment of communications and working relationship growth between CoSA, SAWS, elected officials, and other local governments	Bi-annual	
Update Business Continuity Plan based on findings	45 days after	

DELIVERABLES

Deliverable	Target Date	Owner
Provide feedback on Joint Training Sessions and share training documents	Annually	CoSA EOC
Documented Lessons Learned	1 month after	CoSA EOC
Updated Business Continuity Plan	1 month	CPS Energy

PROJECT/ACTION PLAN RESOURCES

Resource	Role	Estimated Work Hours
William McCarson	Business Continuity	40
Blaize Skocny	Incident Response & Business Continuity	40
GridEx Planners (15 employees)	Support	20

BUDGET

- Annual Joint Training Meeting – $2,400
- GridEx VI – $9,000

METRICS

- Better communication between all parties and an improved response to events affecting our customers
- Tracking of Lessons Learned and corrections of the business continuity plan

APPROVAL

Title	Name	Date
Interim President & CEO	Rudy Garza	12/9/2021
Executive Sponsor	Shanna Ramirez	11/12/2021
Co-Executive Sponsor	Paul Barham	11/12/2021
Response Lead	Garrick Williams	12/06/2021
Business Area POC	Josh Dean	11/12/2021

CPS ENERGY CEP REPORT RECOMMENDATION ACTION PLAN

CEPR SAWS 16

CEPR SAWS 16 - SAWS and CPS Energy should meet to discuss CPS Energy’s compliance with Chapter 25 Subsection C (Infrastructure and Reliability) of the Public Utility Commission’s Electric Substantive Rules and discuss the role of SAWS in respect to these compliance measures.

PLAN OVERVIEW

Executive Sponsor	**Lisa Lewis**
Name of Action/Project	CEPR SAWS 16
Co-executive Sponsor	Paul Barham, Frank Almaraz
Point of Contact	Bob Stevens
Action Plan Development Team	Bob Stevens, James Carter, Clayton Kruse, Rick Maldonado, Melissa Gutierrez

OBJECTIVE

The City of San Antonio requests that CPS Energy and SAWS meet to discuss PUCT Rules 25.52 & 25.53 (Rules). CPS Energy will share the Rules with SAWS and verify the mutual understanding. Specifically, the Rule defines Critical Load. SAWS has some facilities that will be identified as Critical Load. PUCT Rule 25.53 describes the handling of Critical Loads. CPS Energy will work to seek concurrence on what the Rules require. Based upon that understanding, SAWS will assist CPS Energy in identifying what is considered a Critical Load.

RECOMMENDATION CATEGORY/DESCRIPTION

BENEFITS/REWARDS

- Both SAWS and CPS Energy will have a common understanding of what is considered a Critical Load
- Clarifies Roles and Responsibilities between SAWS and CPS Energy
- Enhanced communications between SAWS and CPS Energy
- SAWS’ Critical Load Facilities will be identified

RISKS

- If this recommendation is not followed, CPS Energy and SAWS would not have a common understanding of the PUCT Rules 25.52 & 25.53 and be at risk of not having Critical Loads identified

- Lack of understanding will lead to poor communications between CPS Energy and SAWS
- Lack of communication could result in a repeat of critical facilities not being identified and the potential for repeat of Winter Storm Uri issues

DETAILS

ACTION PLAN/PROJECT DETAILS

- Draft correspondence for SAWS to solicit common understanding of CEPR SAWS 16 Recommendation
- Seek approval of common understanding
- Work with SAWS to identify Critical Loads
- Present the plan to Executive Management of CPS Energy and SAWS and make modifications if required
- Utilizing the plan developed in CEPR EOC 10 communicate to affected entities

EXECUTION

IMPLEMENTATION TIMELINE

July 23, 2021 – October 15, 2021

MILESTONES

Milestone	Target Date	Status/ Comment
Draft correspondence for SAWS to solicit common understanding of CEPR SAWS 16 Recommendation	8/26/2021	Complete
Obtain approval from SAWS of common understanding	9/3/2021	Complete
Implement a strategy for identification and management of Critical Loads	10/4/2021	Complete
Identify SAWS' Critical Loads	10/4/2021	Complete

DELIVERABLES

Deliverable	Target Date	Status/ Comment
SAWS provide a list of Critical Loads	10/4/2021	Complete

RESOURCES

BUDGET

No budget line items required to address this recommendation.

METRICS

Communications with SAWS will follow the details prescribed in CEPR EOC 10

APPROVAL

Title	Name	Date
Interim CEO	Rudy Garza	11/23/2021
Executive Sponsor	Lisa Lewis	10/25/2021
Co-Executive Sponsor	Paul Barham	10/20/2021
Co-Executive Sponsor	Frank Almaraz	10/20/2021
Response Lead	Garrick Williams	10/25/2021
Business Area POC	Bob Stevens	10/18/2021

Appendix 8

Consolidated CEP Recommendations & CPS Energy Lesson Learned

Count	Type	CEPR / ULL Category	Revised Recommendation / Lesson Learned	Status	Community Value	Estimated Completion Date
1	CEPR	Deregulation Failure (Reserve Capacity)	Recommendation: Support development of legislation that ensures ERCOT has sufficient energy reserve capacity from all generation sources	Submitted to MUC	Legislation enabling market redesign will allow ERCOT to better manage load levels efficiently during extreme weather events.	12/31/2021
2	CEPR	Deregulation Failure (Interconnection)	Recommendation: Support the state's evaluation of making an investment to connect to grids outside of Texas	Submitted to MUC	Legislation enabling market redesign will allow ERCOT to better manage load levels efficiently during extreme weather events.	12/31/2021
3	CEPR	Deregulation Failure (Loans for Add'l Generation)	Recommendation: Suggest that the state pursue efforts to guarantee loans to build or contract additional capacity to meet demands	Submitted to MUC	Legislation enabling market redesign will allow ERCOT to better manage load levels efficiently during extreme weather events.	12/31/2021
4	CEPR	Free Market Interference (Natural Gas Supply Strategy)	Recommendation: Enhance current practices for purchasing and transporting natural gas	Submitted to MUC	Expanding options to enable access to sufficient affordable natural gas for our generation assets and customers even during periods of peak demand and extreme weather.	12/1/2021
5	CEPR	Free Market Interference (PUC/ERCOT Price Manipulation)	Recommendation: Support legislation that eliminates the ability for the PUC to direct artificial electric power price manipulation through ERCOT	Submitted to MUC	Legislation enabling market redesign will mitigate against the risk of elevated pricing driven by factors other than scarcity/demand.	9/1/2023
6	CEPR	Plant Operational Problems (Generation Operational	Recommendation: Support operational excellence at generation plants through renewed emphasis and focus on best practices. Several items also identified as a lessons learned.	Submitted to MUC	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	12/31/2021
7	CEPR	Power Outage Distribution Equity (Load Shed Automation	Recommendation: CPS Energy should review the automated rotating outages process. Also identifed as a lesson learned.	Submitted to MUC	Improved efficiency managing mandatory loadshed and outages increases equity in impact of loadshed events on customers.	
8	CEPR	Power Outage Distribution Equity (Load Shed Circuit Management)	Recommendation: Review options for mandatory loadshed management and coordinate with critical service providers. Several items also identified as a lessons learned.	Submitted to MUC	Enable critical service providers to better plan for impact and recovery from mandatory load shed events.	
9	CEPR	Power Outage Distribution Equity (Critical Infrastructure	Recommendation: Assist SAWS in securing redundancy for its critical facilities	Submitted to MUC	Enable SAWS to continue providing service during outages.	
10	CEPR	Communications (Emergency Communications	Recommendation: Collaborate with the CoSA EOC to develop emergency communications procedures	Submitted to MUC	Enable consistent messaging during emergencies.	
11	CEPR	Communications (Customer/Mission Focus)	Recommendation: Simplify customer messaging with focus on safety and clear calls to action. Also identified as a lesson learned.	Submitted to MUC	Enable customers to educate themselves, prepare for emergencies and mitigate their risks.	
12	CEPR	Communications (Conservation Plans and Operations)	Recommendation: Revise and enhance how calls for conservation are communicated to the public. Also identified as a lesson learned.	Submitted to MUC	Increase understanding of and participation in conservation events and reduce demand during peak periods.	

Consolidated CEP Recommendations & CPS Energy Lesson Learned

Count	Type	CEPR / ULL Category	Revised Recommendation / Lesson Learned	Status	Community Value	Estimated Completion Date
13	CEPR	Communications (Advanced Customer Notification)	Recommendation: Develop advanced notification process for mandatory load shed event. Also identified as a lesson learned.	Submitted to MUC	Provide the most notice possible of likely mandatory load shed and outage events.	
14	CEPR	Communications (EOC Coordination)	Recommendation: Coordinate messaging with the EOC	Submitted to MUC	Enable consistent messaging during emergencies.	
15	CEPR	Communications (Advanced Notification Timelines)	Recommendation: Provide advanced notification of mandatory load shed events where possible	Submitted to MUC	Provide the most notice possible of likely mandatory load shed and outage events.	
16	CEPR	Communications (Critical Circuit Status Notification)	Recommendation: Consider informing customer if they are subject to the risk of power loss during mandatory load shed events	Submitted to MUC	Enable customers to educate themselves, prepare for emergencies and mitigate their risks.	
17	CEPR	Communications (Customer Outage Helpful Tips)	Recommendation: Provide customer with key information for support services	Submitted to MUC	Enable customers to educate themselves, prepare for emergencies and mitigate their risks.	
18	CEPR	Communications (Emergency Preparedness Campaign)	Recommendation: Collaborate with the CoSA and municipal partners to develop a continuous emergency preparedness campaign	Submitted to MUC	Enable customers to educate themselves, prepare for emergencies and mitigate their risks.	
19	CEPR	Shared (Uninterruptible circuits)	Recommendation: Support SAWS in developing a plan that ensures resiliency for water and sewer services.	Submitted to MUC	Enable SAWS to continue providing service during outages.	
20	CEPR	Shared (Back-up power)	Recommendation: Support SAWS in identifying locations that require continuous power to increase resiliency for water and sewer services.	Submitted to MUC	Enable SAWS to continue providing service during outages.	10/29/2021
21	CEPR	Shared (Joint Exercises)	Recommendation: Support SAWS in performing routine disaster scenarios with the EOC	Submitted to MUC	Reduce response and recovery time during emergencies.	10/15/2021
22	CEPR	Shared (Communication)	Recommendation: Support SAWS in developing communications protocols	Submitted to MUC	Enable SAWS to continue providing service during outages.	
23	CEPR	Shared (PUC Compliance)	Recommendation: Support SAWS in efforts to comply with PUC rules	Submitted to MUC	Enable SAWS to continue providing service during outages.	
24	CEPR	URI & EOC Operations (Hazard Mitigation Plan Input)	Recommendation: Support CoSA EOC's efforts to update the Hazard Mitigation Plan (HAP)	Submitted to MUC	Enhance ability to learn from and better plan for emergencies.	10/15/2021

Consolidated CEP Recommendations & CPS Energy Lesson Learned

Count	Type	CEPR / ULL Category	Revised Recommendation / Lesson Learned	Status	Community Value	Estimated Completion Date
25	CEPR	URI & EOC Operatio	Recommendation: Collaborate with the CoSA EOC to identify backup communication devices	Submitted to MUC	Increase resiliency of communication capabilities during emergencies.	12/31/2021
26	CEPR	URI & EOC Operations (Back-up Generator Plan)	Recommendations: Support CoSA EOC's effort to improve resiliency at critical locations	Submitted to MUC	Minimize impact of outages and mandatory load shed events on critical CoSA locations and essential services.	10/29/2021
27	CEPR	URI & EOC Operations (Remote Work Contingency Plan)	Recommendations: Support CoSA EOC's effort to develop workforce remote work contingency plans	Submitted to MUC	Increase resiliency of essential services and workers during emergencies.	10/15/2021
28	CEPR	URI & EOC Operations (Power Outage Exercises)	Recommendation: Support the EOC in developing a contingency exercise program	Submitted to MUC	Increase resiliency of essential services and workers during emergencies.	10/15/2021
29	CEPR	URI & EOC Operations (Emergency Response Training)	Recommendation: Support the CoSA EOC's effort to enhance cross-department/discipline emergency response training	Submitted to MUC	Increase resiliency of essential services and workers during emergencies.	10/15/2021
30	CEPR	URI & EOC Operations (Annual Tabletop Exercise Plan)	Recommendation: Support the CoSA EOC in creating an annual emergency response exercise program	Submitted to MUC	Increase resiliency of essential services and workers during emergencies.	10/15/2021
31	CEPR	Cascading Events (Contingency Operational Authority)	Recommendation: Strengthen communication and decision making channels to support CoSA's emergency preparedness and response	Submitted to MUC	Improve community resiliency during emergencies.	
32	CEPR	Cascading Events (Load Shed Authority)	Recommendation: Strengthen communication and decision making channels during mandatory load shed events	Submitted to MUC	Improve community resiliency during emergencies.	
33	CEPR	Outage Impact (Coordinated Communications)	Recommendation: Collaborate with the CoSA EOC to provide a common operating picture	Submitted to MUC	Improve community resiliency during emergencies.	
34	CEPR	Outage Impact (Coordinated Media Briefings)	Recommendation: Collaborate with the CoSA EOC to on daily media briefings	Submitted to MUC	Enable consistent messaging during community emergencies.	
35	CEPR	Outage Impact (Call Center Improvements)	Recommendation: Collaborate with the CoSA EOC to improve the customer experience	Complete	Enable customers to educate themselves, prepare for emergencies and mitigate their risks.	
36	CEPR	Outage Impact (Load Shed Coordination & Communication)	Recommendation: Strengthen communication and decision making channels during mandatory load shed	Submitted to MUC	Enable consistent messaging during community emergencies.	
37	CEPR	Outage Impact (Operational Dashboard)	Recommendation: Collaborate with the CoSA EOC in creating a dashboard to provide near-time information	Submitted to MUC	Improve community resiliency during emergencies.	

Consolidated CEP Recommendations & CPS Energy Lesson Learned						
Count	**Type**	**CEPR / ULL Category**	**Revised Recommendation / Lesson Learned**	**Status**	**Community Value**	**Estimated Completion Date**
38	Uri LL	Grid Operations	Lesson Learned: Additional workforce availability would improve restoration capabilities	Complete	Improve ability to respond quickly during restoration efforts.	-
39	Uri LL	Grid Operations	Lesson Learned: COVID related fixed crew structure limited restoration efficiency	Complete	Improve ability to respond quickly during restoration efforts.	-
40	Uri LL	Communication	Lesson Learned: System Operations was limited by COVID-19 quarantine protocols	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	-
41	Uri LL	Grid Operations	Lesson Learned: Restoring large amounts of load following a widespread extended outage resulted in high volume of additional unexpected outages.	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	11/15/2021
42	Uri LL	Communication	Lesson Learned: Activation of essential employees during inclement weather and load shed events can be improved	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	-
43	Uri LL	Communication	Lesson Learned: Increased communication by leadership during inclement weather and load shed events is requested by workforce	Implemented	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	12/1/2021
44	Uri LL	Grid Operations	Lesson Learned: Radio and cellular service failures should be anticipated during weather and load shed events	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	12/23/2021
45	Uri LL	General Observatior	Lesson Learned: Crisis Management Team was not formally activated prior to operationalizing response plans	Complete	Continuous improvement in incident response practices and improved operational excellence.	-
46	Uri LL	Personnel Issues	Lesson Learned: Timekeeping errors can be reduced with greater clarity on applicable time codes during emergencies	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	12/1/2021
47	Uri LL	Grid Operations	Lesson Learned: Certain key facilities were affected by mandatory load shed	Complete	Resiliency at key facilities will improve quality and speed of restoration efforts.	-
48	Uri LL	Facility Operations	Lesson Learned: Facilities need ancillary items to support personnel during extended duration emergencies	Complete	Ensure workforce is able to continue safe restoration efforts during extended duration emergencies.	12/15/2021
49	Uri LL	Facility Operations	Lesson Learned: Facilities need custodial support during extended duration emergencies	Complete	Ensure workforce is able to continue safe restoration efforts during extended duration emergencies.	12/31/2021
50	Uri LL	Facility Operations	Lesson Learned: Meal sourcing capability required for essential workers during extended outage and restoration events	Complete	Ensure workforce is able to continue safe restoration efforts during extended duration emergencies.	-
51	Uri LL	Facility Operations	Lesson Learned: Unique security needs arose during extended outage and restoration events at certain key facilities	Complete	Secure safety of people and assets.	12/15/2021

Consolidated CEP Recommendations & CPS Energy Lesson Learned						
Count	**Type**	**CEPR / ULL Category**	**Revised Recommendation / Lesson Learned**	**Status**	**Community Value**	**Estimated Completion Date**
52	Uri LL	Grid Operations	Lesson Learned: Additional training and exercises are requested by workforce to prepare for and better respond during extended load shed and extreme weather events	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	6/30/2021
53	Uri LL	Physical Security	Lesson Learned: Additional training and communication is needed to ensure employess are aware of all contingency operation protocols.	Complete	Secure safety of people and assets.	12/15/2021
54	Uri LL	Facility Operations	Lesson Learned: Key facilities were impacted by water and wastewater outages	Complete	Ensure workforce is able to continue safe restoration efforts during extended duration emergencies	10/1/2021
55	Uri LL	Supply Chain	Lesson Learned: Alternate fuel source availability would improve response capabilities	Complete	Ensure workforce is able to continue safe restoration efforts during extended duration emergencies	10/1/2021
56	Uri LL	Supply Chain	Lesson Learned: Lodging capability would improve response capabilities during extended duration emergencies	Complete	Ensure workforce is able to continue safe restoration efforts during extended duration emergencies.	12/31/2021
57	Uri LL	Personnel Issues	Lesson Learned: Additional training is requested on backup manual timekeeping practices	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	12/31/2021
58	Uri LL	Grid Operations	Lesson Learned: Opportunity to update certain technical systems and equipment for greater resiliency	Complete	Continuous improvement of key systems and practices enables increased resiliency and operational excellence.	12/1/2024
59	Uri LL	Supply Chain	Lesson Learned: Identify and source extreme cold weather gear for employees	Complete	Ensures workforce is able to continue safe restoration efforts during extreme weather restoration events.	12/15/2021
60	Uri LL	Grid Operations	Lesson Learned: Opportunity to improve crew recall process during extreme weather events	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	-
61	Uri LL	Grid Operations	Lesson Learned: Increased communications between service districts and fleet is requested by workforce during extreme weather events	Complete	Ensure workforce is able to continue safe restoration efforts during extended duration emergencies.	6/30/2021
62	Uri LL	Grid Operations	Lesson Learned: Realtime evaluation of circuit overloads on the grid required during extreme weather	Complete	Enhances ability to restore power and reduce unexpected outages.	11/15/2021
63	Uri LL	Grid Operations	Lesson Learned: Review equipment settings to help with restoring large amounts of load following a widespread extended outage.	Complete	Correcting the equipment settings to help restore large amounts of load will minimize continued unexpected outages following a widespread extended outage.	12/15/2021
64	Uri LL	Grid Operations	Lesson Learned: Opportunity to review and adjust winter peak modeling for distribution and transmission	Complete	Continuous improvement of key systems and practices enables increased resiliency and operational excellence.	12/17/2021

Consolidated CEP Recommendations & CPS Energy Lesson Learned						
Count	**Type**	**CEPR / ULL Category**	**Revised Recommendation / Lesson Learned**	**Status**	**Community Value**	**Estimated Completion Date**
65	Uri LL	Grid Operations	Lesson Learned: Opportunity to increase workforce efficiency with additional communications equipment for workforce during extended duration emergencies	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	10/27/2021
66	Uri LL	Grid Operations	Lesson Learned: Additional training on communications equipment operations is requested by workforce	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	10/27/2021
67	Uri LL	Grid Operations	Lesson Learned: Additional training and practice of 24 hour coverage models at all levels is requested by workforce	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	11/15/2021
68	Uri LL	Grid Operations	Lesson Learned: Generator availability enables equipment resiliency during extended emergencies	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	12/1/2021
69	Uri LL	Grid Operations	Lesson Learned: Opportunity to review and update shift lengths and crew rotation planning	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	11/15/2021
70	Uri LL	Grid Operations	Lesson Learned: Increased preventive maintenance for critical facilities will reduce the impact of mandatory load shed and extreme weather events	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	11/27/2021
71	Uri LL	Grid Operations	Lesson Learned: Thermostats that automatically switch between heat and cool will improve resiliency of key equipment	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	10/27/2021
72	Uri LL	Grid Operations	Lesson Learned: Ensure all key personnel have access to customers' access controlled areas	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	10/11/2021
73	Uri LL	Grid Operations	Lesson Learned: Explore options to further mitigate risks of frozen or ice laden transmission line movement in high winds	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	12/14/2021
74	Uri LL	Improvement	Lesson Learned: Opportunity to improve remote workforce efficiency during extended duration emergencies	Complete	Continuous improvement of restoration practices allows for increased resiliency and improved operational excellence.	10/28/2021
75	Uri LL	Improvement	Lesson Learned: Opportunity for increased resiliency for Direct Current power plants that support communications equipment	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	12/27/2021
76	Uri LL	Improvement	Lesson Learned: Opportunity for increased resiliency for AMI network infrastructure	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	10/31/2021
77	Uri LL	Communication	Lesson Learned: Improve communication between business areas during extended duration emergencies	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	12/29/2021
78	Uri LL	Improvement	Lesson Learned: Opportunity for additional operational readiness testing on equipment supporting critical systems	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	12/21/2021

Consolidated CEP Recommendations & CPS Energy Lesson Learned						
Count	**Type**	**CEPR / ULL Category**	**Revised Recommendation / Lesson Learned**	**Status**	**Community Value**	**Estimated Completion Date**
79	Uri LL	Improvement	Lesson Learned: Priority alert levels for the Network Operations Center will improve efficiencies	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	11/1/2021
80	Uri LL	Improvement	Lesson Learned: Opportunities for more efficient staging of support vehicles during extended duration emergencies	Complete	Ensure workforce is able to continue safe restoration efforts during extended outage and restoration events duration emergencies.	10/20/2021
81	Uri LL	Improvement	Lesson Learned: Opportunity for increased resiliency and visibility into status of communications shelters during extreme weather conditions	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	12/27/2021
82	Uri LL	Plant Operations	Lesson Learned: Increase fuel oil storage capacity for and prior to extended duration emergencies	Complete	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	12/31/2021
83	Uri LL	Improvement	Lesson Learned: Increase consumable chemicals prior to extended duration emergencies	Complete	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	11/30/2022
84	Uri LL	Improvement	Lesson Learned: Additional portable heaters will increase resiliency at facilities during extreme weather events	Complete	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	11/30/2021
85	Uri LL	Improvement	Lesson Learned: Opportunity to increase resiliency through contract support plan for supplemental staff services during extended duration emergencies	Complete	Continuous improvement of key systems and practices enables increased resiliency operational excellence.	1/30/2022
86	Uri LL	Improvement	Lesson Learned: Review and update facility specific inventory to ensure adequacy during extreme weather events	Complete	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	11/30/2021
87	Uri LL	Plant Operations	Lesson Learned: Opportunity to increase water pressure monitoring for key facilities	Complete	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	11/30/2022
88	Uri LL	Improvement	Lesson Learned: Review plant-specific equipment, parts and supply inventory to increase resiliency during extreme weather events	Complete	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	11/30/2022
89	Uri LL	Plant Operations	Lesson Learned: Update battery storage procedures to address operations during ERCOT system emergency conditions	Complete	Ensures availability of generation units to provide reliable power and enhances resiliency during extreme weather events.	11/30/2021
90	Uri LL	Improvement	Lesson Learned: Update winter preparation training for all plant personnel	Complete	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	1/15/2022
91	Uri LL	Plant Operations	Lesson Learned: Update gas yard inspection protocols for facilities feeding plant sites	Implemented	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	11/30/2022
92	Uri LL	Communication	Lesson Learned: Update rating agencies during extended duration emergencies	Implemented	Mitigate impact of emergency events on financial stability of enterprise.	On-going
93	Uri LL	General Observatior	Lesson Learned: Secure additional liquidity and manage metrics	Implemented	Mitigate impact of emergency events on financial stability of enterprise.	On-going

Consolidated CEP Recommendations & CPS Energy Lesson Learned						
Count	**Type**	**CEPR / ULL Category**	**Revised Recommendation / Lesson Learned**	**Status**	**Community Value**	**Estimated Completion Date**
94	Uri LL	Improvement	Lesson Learned: Opportunity to increase resiliency through contract for supplemental fuel oil	Complete	Continuous improvement of operational practices mitigates against risk of plant outages during periods of peak demand and extreme weather.	3/1/2022
95	Uri LL	General Observation	Lesson Learned: Review vendor continuity plans	Complete	Improves our resiliency by inspecting and maintaining equipment that may fail during extreme weather.	1/31/2022
96	Uri LL	System Operations	Lesson Learned: Restoring large amounts of load following a widespread extended outage cause low pressure on gas lines	Complete	Improves our resiliency by inspecting and maintaining equipment that may fail during extreme weather.	12/1/2021
97	Uri LL	Improvement	Lesson Learned: Opportunity to increase efficiency through gas mutual aid assistance	Implemented	Improves our resiliency by inspecting and maintaining equipment that may fail during extreme weather.	12/21/2021
98	Uri LL	System Operations	Lesson Learned: Opportunity for additional preventive maintenance and emergency preparedness protocols for extreme weather events	Implemented	Improves our resiliency by inspecting and maintaining equipment that may fail during extreme weather.	3/1/2021
99	Uri LL	Communication	Lesson Learned: Opportunity to review and revise timing of initiatives in Storm Safety Communication Plan	Complete	Ensures crew safety during restoration operations.	11/15/2021
100	Uri LL	Improvement	Lesson Learned: Opportunity to evaluate need for extreme weather vehicles and vehicle equipment	Complete	Ensures crew safety during restoration operations.	1/31/2022
101	Uri LL	Improvement	Lesson Learned: Opportunity to increase security threat awareness communication protocols for extended duration emergencies	Complete	Improved efficiency managing mandatory loadshed and outages increases equity in impact of loadshed events on customers	12/18/2021
102	Uri LL	Improvement	Lesson Learned: Develop methodology to gain clear picture of actual outage experience	Complete	Improves restoration operations by reducing the margin of error.	-
103	Uri LL	Improvement	Lesson Learned: Develop Customer Emergency Preparedness material	Complete	Enable customers to educate themselves, prepare for emergencies and mitigate their risks.	-
104	Uri LL	Improvement	Lesson Learned: Opportunity to improve My Energy Portal to provide clear and complete customer information	Complete	Continuous improvement of key systems and practicesenables increased resiliency and operational excellence.	2/26/2021
105	Uri LL	Improvement	Lesson Learned: Provide stakeholders with updates on outage events they can share with their contacts.	Complete		-
106	Uri LL	Improvement	Lesson Learned: Cross train department members to serve as backups in the event of an emergency.	Complete		-
107	Uri LL	Improvement	Lesson Learned: Launch education campaign for customers to update thier contact information so we can reach them in the time of an emergency.	Complete		-
Legend: CEPR - Committee on Emergency Preparedness Recommendation Uri LL - Winter Storm Uri Lesson Learned						