The Timeline and Events of the February 2021 Texas Electric Grid Blackouts

July 2021

The University of Texas at Austin
Energy Institute

The Timeline and Events of the February 2021 Texas Electric Grid Blackouts

A report by a committee of faculty and staff at The University of Texas at Austin

July 2021

COMMITTEE CHAIRS

Carey W. King, *Research Scientist, Assistant Director, Energy Institute*
Josh D. Rhodes, *Research Associate, Department of Mechanical Engineering*
Jay Zarnikau, *Research Fellow, Department of Economics*

COMMITTEE MEMBERS

Contributing Authors
Ning Lin, *Chief Economist, Bureau of Economic Geology*

Additional Members
Erhan Kutanoglu, *Associate Professor, Operations Research and Industrial Engineering, Department of Mechanical Engineering*
Benjamin Leibowicz, *Assistant Professor, Operations Research and Industrial Engineering, Department of Mechanical Engineering*
Dev Niyogi, *Professor, Department of Geological Sciences; Professor, Department of Civil, Architectural, and Environmental Engineering*
Varun Rai, *Professor, LBJ School of Public Affairs; Director, Energy Institute*
Surya Santoso, *Professor, Department of Electrical and Computer Engineering*
David Spence, *Baker Botts Chair in Law, School of Law; Professor, Department of Business, Government, and Society*
Stathis Tompaidis, *Professor, Department of Information, Risk and Operations Management, and by courtesy, Department of Finance*
Hao Zhu, *Assistant Professor, Department of Electrical and Computer Engineering*

OTHER CONTRIBUTORS

Erik Funkhouser, *Director for Research Coordination and Partnerships, Energy Institute*
Brent Austgen, *Graduate Research Assistant, Operations Research and Industrial Engineering Program, Department of Mechanical Engineering*

Table of Contents

List of Figures

Chapter Three

Appendix A

Appendix C

Appendix D

List of Tables

Executive Summary

Objective

This report recounts the factors contributing to disruptions in electricity and natural gas service in Texas during Winter Storm Uri, with a particular focus on blackouts on the Electric Reliability Council of Texas (ERCOT) grid during the period from February 15-18, 2021. Our goal is to create a common basis of fact to educate the debate over strategies to avoid similar problems in the future. We specifically limited the scope of this report to the events during February 2021, a comparison of the February 2021 event to the previous energy system disruptions in 1989 and 2011 during winter storms, and the economic consequences of the event in February 2021. An appendix describes the long-term evolution of the ERCOT electricity market and provides historical context.

This report is not intended to comprehensively address all issues stemming from such a complex event, but may inform subsequent assessments. This report does not recommend policies or solutions.

Data

To perform the analysis presented in this report, we reviewed a variety of public information sources, analyses conducted by the staff of ERCOT, testimony before state legislative committees, and public data archives provided by ERCOT. In addition, and through an agreement with the Public Utility Commission of Texas (PUCT), select members of our project team were provided access to certain confidential data collected by the PUCT and ERCOT pertaining to the performance of specific electric generating units, enrollment of energy consumers in ERCOT's Emergency Response Service program, communications regarding the winter storm, and other relevant information.[1] We also used a proprietary source of data to explore the performance of the natural gas industry during the event. We further considered and analyzed meteorological and other technical data that groups within the University of Texas at Austin (UT) have acquired for other research purposes.

Findings

The failure of the electricity and natural gas systems serving Texas before and during Winter Storm Uri in February 2021 had no single cause. While the 2021 storm did not set records for the lowest recorded temperatures in many parts of the state, it caused generation outages and a loss of electricity service to Texas customers several times more severe than winter events leading to electric service disruptions in December 1989 and February 2011. The 2021 event exceeded prior events with respect to both the number and capacity of generation unit outages, the maximum

[1] Josh Rhodes and Carey King of the project team were provided access to the confidential data.

load shed (power demand reduction) and number of customers affected, the lowest experienced grid frequency (indicating a high level of grid instability), the amount of natural gas generation experiencing fuel shortages, and the duration of electric grid operations under emergency conditions associated with load shed and blackout for customers. The financial ramifications of the 2021 event are in the billions of dollars, likely orders of magnitude larger than the financial impacts of the 1989 and 2011 blackouts.

Factors contributing to the electricity blackouts of February 15-18, 2021 include the following:

- *All types of generation technologies failed*. All types of power plants were impacted by the winter storm. Certain power plants within each category of technologies (natural gas-fired power plants, coal power plants, nuclear reactors, wind generation, and solar generation facilities) failed to operate at their expected electricity generation output levels.
- *Demand forecasts for severe winter storms were too low.* ERCOT's most extreme winter scenario underestimated demand relative to what actually happened by about 9,600 MW, about 14%.
- *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.
- *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.
- *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. From noon on February 14 to noon on February 15, the amount of offline wind capacity increased from 14,600 MW to 18,300 MW (+3,700 MW).[2] Offline natural gas capacity increased from 12,000 MW to 25,000 MW (+13,000 MW). Offline coal capacity increased from 1,500 MW to 4,500 MW (+3,000 MW). Offline nuclear capacity increased from 0 MW to 1,300 MW, and offline solar capacity increased from 500 MW to 1100 MW (+600 MW), for a total loss of 24,600 MW in a single 24-hour period.

---

[2] For wind and solar electricity generation, nameplate capacity is not a meaningful measure of the amount of power generation expected when the unit is not experencing an outage, though nameplate capacity provides a meaningful metric for the thermal fleet of power plants (e.g., coal, nuclear, and natural gas-fired generating units). Using backcasted values of the available wind and solar radiation, available wind capacity outages actually decreased from 9,070 MW to 5,020 MW (-4,050) over the same time period and solar outages increased less, from 108 MW to 545 MW (+437 MW).

- *Power plants listed a wide variety of reasons for going offline throughout the event.* [3] Reasons for power plant failures include "weather-related" issues (30,000 MW, ~167 units), "equipment issues" (5,600 MW, 146 units), "fuel limitations" (6,700 MW, 131 units), "transmission and substation outages" (1,900 MW, 18 units), and "frequency issues" (1,800 MW, 8 units). [4]
- *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.
- *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. Dry gas production dropped 85% from early February to February 16, with up to 2/3 of processing plants in the Permian Basin experiencing an outage.[5]
- *Failures within the natural gas system began prior to electrical outages.* Days before ERCOT called for blackouts, natural gas was already being curtailed to some natural gas consumers, including power plants.
- *Some critical natural gas infrastructure was enrolled in ERCOT's emergency response program.* Data from market participants indicates that 67 locations (meters) were in both the generator fuel supply chain and enrolled in ERCOT's voluntary Emergency Response Service program (ERS), which would have cut power to them when those programs were called upon on February 15. At least five locations that later identified themselves to the electric utility as critical natural gas infrastructure were enrolled in the ERS program.
- *Natural gas in storage was limited.* Underground natural gas storage facilities were operating at maximum withdrawal rates and reached unprecedently-low levels of working gas, indicating that the storage system was pushed to its maximum capability.

The ERCOT system operator managed to avoid a catastrophic failure of the electric grid despite the loss of almost half of its generation capacity, including some black start units that would have been needed to jump-start the grid had it gone into a complete collapse.

---

[3] Some power plants experienced multiple outages and may be included in more than one category.

[4] The maximum values during the event are presented here for both capacity and numbers of units. Different categories may have experienced peak outage rates at different times.

[5] Based on our data sample of 27 natural gas processing plants.

Had one or more of the problems listed above not occurred, outages might still have occurred, but their duration and severity would likely have been lower. The magnitude of the failures caused unprecedented impacts:

- Rolling blackouts turned into persistent days-long electrical outages affecting millions of Texans connected to the ERCOT grid and leading to loss of life.
- The financial impacts were tremendous. According to PUCT data, natural gas prices, normally much less than $10/MMBTU, spiked to over $400/MMBTU at Texas trading hubs. Natural gas providers that were able to produce and transport gas reported windfall profits. Many financial sector firms that operate in the ERCOT energy market also reported large profits.
- The price of electricity spiked to $9,000 per MWh and stayed there by orders of the PUCT, which suspended some market price setting rules during the electricity blackouts. The PUCT stated that high prices were intended to ensure that generating units would participate in the market and that price-sensitive energy consumers would minimize their demand for electricity from the market. The PUCT also stated that the suspension of the rules was due to two reasons. First, to account for load that had been removed due to forced outages from the calculation of prices. Second, to avoid potentially even higher electricity prices that would result from the high price of natural gas.[6]
- The financial losers included power generators whose equipment failed, generators dependent upon natural gas that were unable to obtain the fuel or were unhedged to high natural gas prices, and load serving-entities (retail electric providers, municipal utility systems, and rural electric cooperatives) who were inadequately hedged.
- Many market participants defaulted on their payment obligations to ERCOT, which serves as a central counter-party in the markets for electrical energy and ancillary services that it administers. These defaults may translate into increased costs for electricity consumers in Texas for many years to come.

Disclaimers

This report was funded in part by the PUCT via an Interagency Agreement with the University of Texas at Austin (UT). Beyond funding, the Interagency Agreement between the PUCT and UT provided certain members of the research team, under a confidentiality agreement, with access to electricity market participant data and other confidential information collected by the PUCT and ERCOT. The PUCT reviewed a draft of this report to ensure that no confidential information was inadvertently disclosed. The committee had full discretion as to the content and presentation of material in the report.

[6] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

Any opinions or positions expressed in this report are those of the authors alone and do not reflect any official positions of the PUCT, ERCOT, the University of Texas at Austin, or the Board of Regents of the University of Texas.

1. Introduction

1.1 Objective

This report recounts the factors contributing to the disruptions in electricity and natural gas service in Texas during Winter Storm Uri, with a particular focus on the outages in electrical service in the Electric Reliability Council of Texas (ERCOT) power region during the period from February 15-18, 2021. In pursuing this report's objective, the Energy Institute at the University of Texas at Austin assembled a team of faculty and researchers to identify and review credible sources of data in an attempt to provide a factual account of what happened and what went wrong during the winter storm.

Our goal is not to provide recommendations, but to create a common basis of fact to educate the debate over policy changes under consideration as a response to the winter storm. We specifically limited the scope of this report to the events and economic impacts of February 2021, including a comparison to previous winter storm blackouts of 1989 and 2011. To provide additional historical context, we include an appendix that describes the long-term evolution of the ERCOT electricity market. This report is not intended to comprehensively address all issues stemming from such a complex event, but can inform future assessments.[7]

This report was funded in part by the Public Utility Commission of Texas (PUCT). Beyond funding, the Interagency Agreement between the PUCT and the University of Texas at Austin (UT) provided the research team with access to confidential electricity market information under a confidentiality agreement. The PUCT reviewed a draft of this report to ensure that no confidential information was inadvertently disclosed, but any views expressed are solely those of the authors and supporting committee members. The authors had full discretion as to the content and presentation of material in the report.

Various participants in the state's natural gas and electricity markets fund research at UT, and some contributors to this report have performed such funded research or provide consulting assistance to companies or organizations involved in the energy industry. Disclosures of any relationships that might be perceived to introduce a conflict of interest are available via the UT Energy Institute and at: https://energy.utexas.edu/ercot-blackout-2021.

[7] Other reports might include a more-comprehensive or focused analyses that might later be developed by the Federal Energy Regulatory Commissions (FERC), the North American Electric Reliability Corporation (NERC), the PUCT, or other government bodies.

1.2. Energy in Texas

Texas is the nation's leading state in electricity and natural gas in both production and consumption. Electricity is provided to the majority of the state's consumers through an intra-state grid, managed by ERCOT as an independent system operator, with limited interconnection to the other two main electrical grids serving the U.S. and Canada, as noted in Figure 1.a. Limited federal regulatory jurisdiction within the ERCOT power region has permitted the development of a unique electricity system involving competition among generators of electricity in the wholesale sector and "customer choice" or retail competition in some areas of the state which were served by vertically-integrated investor-owned utilities prior to 2001.

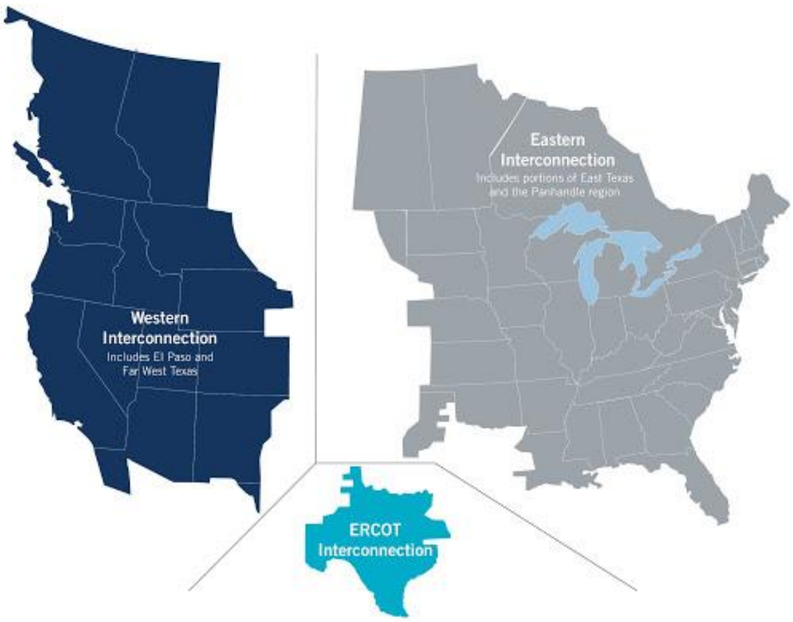


Figure 1.a. ERCOT in relation to the other two grid interconnections in the U.S. and Canada.[8]

Natural gas has long been the leading fuel for the generation of electricity in Texas, although the state has become a leader in the generation of electricity from renewable energy sources in recent years. Despite the interdependence of the state's natural gas and electricity industries, different state agencies have regulatory oversight over the two industries. While the PUCT oversees electricity services (and has regulatory oversight over certain aspects of water and telecommunications services), the natural gas sector is regulated by Texas Railroad Commission (RRC). The PUCT's oversight over the electricity industry includes responsibility for overseeing the operations of the electric grid operator, ERCOT. Appendix A provides

---

[8] ERCOT: http://www.ercot.com/news/mediakit/maps, http://www.ercot.com/content/wcm/landing_pages/89373/ERCOT-Internconnection_Branded.jpg

additional information and historical context pertaining to the development and operation of ERCOT.

The following Chapter 2 reviews the physical aspects of the February 2021 event, examining conditions of the electricity and natural gas industries in the days prior and during the winter storm. Both the demand and supply sides of energy markets are discussed. Chapter 3 examines prices in electricity and natural gas markets, and the impact of the price spikes upon market participants in these industries. Chapter 4 contrasts the February 2021 event to previous winter events in 1989 and 2011 that prompted electrical outages. Chapter 5 provides a brief summary of this report.

2. Timeline of Events Related to February 2021 ERCOT Blackouts

We begin this chapter by recounting the electricity generating capacity anticipated in advance of the event, as suggested by winter resource adequacy analyses conducted by the ERCOT staff and updated information available to the market in the days prior to the event. Electric load forecasts and their underlying weather forecasts and assumptions are reviewed. Operational activities on the electric side are then discussed, including efforts by the grid operator, transmission and distribution providers, and others to constrain the demand for electricity. We conclude this chapter with a focus on natural gas operations before and during the event.

2.1. ERCOT's Winter 2020/2021 SARA report

ERCOT develops a Seasonal Assessment of Resource Adequacy (SARA)[9] report for each of the fall, winter, spring, and summer seasons that "focuses on the availability of sufficient operating reserves to avoid emergency actions such as the deployment of voluntary load reduction resources." Each SARA report is released one to two months before the season under study. In a SARA report, ERCOT assumes a set of hours at which the peak electricity demand will occur. For the winter, ERCOT assumes peak demand will occur between 7 am and 10 am. The winter 2020/2021 SARA report,[10] released on November 5, 2020, indicated that ERCOT's "Forecasted Season Peak Load" scenario expected that about 74,000 MW of net resource capacity[11] would be available to meet a winter peak of 57,699 MW. This includes an assumed *"… unit outage forecast of 8,616 MW during the winter months, which is based on historical winter outage data compiled since 2017*" (Figure 2.a). A quantity of Positive Reserves[12] (far right, green bar of Figure 2.a) above a few thousand megawatts indicates that, under this scenario, the chance of load shed (blackouts) was low. The report also noted that the previous (to 2021) all-time winter peak was 65,915 MW and occurred on January 17, 2018.

---

[9] See: http://www.ercot.com/gridinfo/resource.

[10] SARA-FinalWinter2020-2021: http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.xlsx

[11] Total Resources – Maintenance Outages – Forced Outages (82,513 MW – 4074 MW – 4542 MW = ~74,000 MW)

[12] Positive reserves refers to "Capacity Available for Operating Reserves."

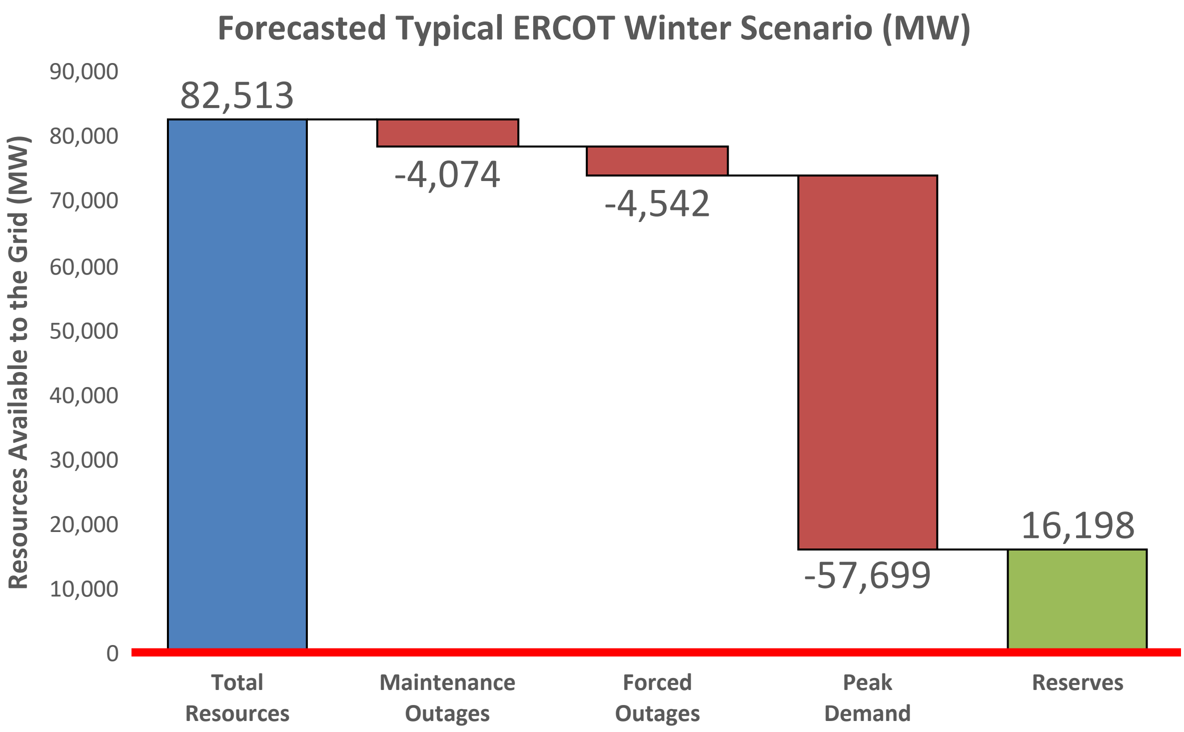


Figure 2.a. Waterfall chart of the ERCOT "Forecasted Season Peak Load" Winter 2020/2021 SARA scenario showing the total amount of Resources assumed for ERCOT as well as expected plant outages and peak demand. This scenario indicated that ERCOT would have over 16,000 MW of reserves, sufficient capacity to match supply and demand.

ERCOT's Winter 2020/2021 SARA scenario indicated the scenario that resulted in the least amount of reserve capacity was the "Extreme Peak Load / Extreme Generation Outages During Extreme Peak Load" scenario (Figure 2.b). This scenario assumed 67,208 MW load and 13,953 MW of thermal power plant outages, such that there would be only 1,352 MW of operating reserves. This level of reserves is below 2,300 MW, a level that ERCOT indicates is at risk of Energy Emergency Alert actions.[13] This "extreme" scenario did not assume any downward adjustments for low wind output, but ERCOT's "Extreme Low Wind Output" SARA scenario does assume a downward adjustment of 5,279 MW.

[13] http://www.ercot.com/content/wcm/lists/164134/EEA_OnePager_FINAL.PDF

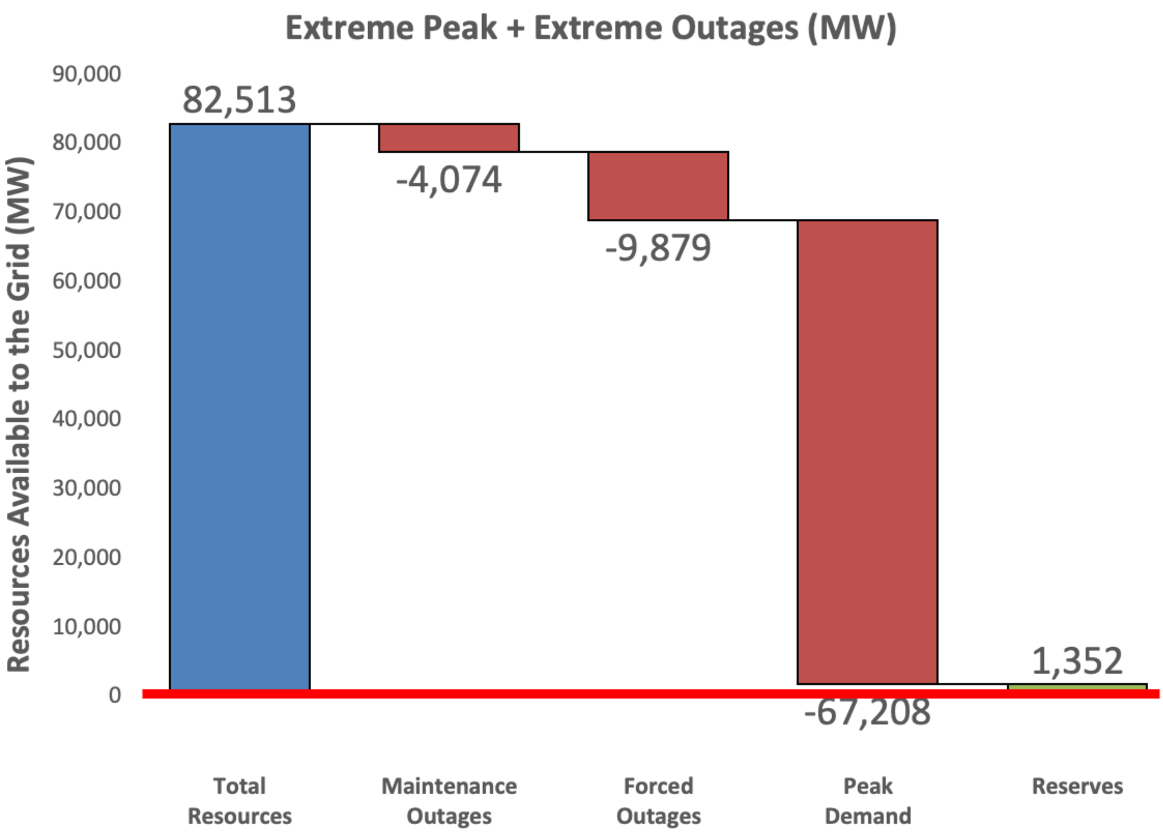


Figure 2.b. Waterfall chart of the ERCOT "Extreme Peak Load / Extreme Generation Outages During Extreme Peak Load" Winter 2020/2021 SARA scenario. This scenario indicated that ERCOT would have only 1,352 MW of reserves, insufficient capacity to prevent an Energy Emergency Alert.

Figure 2.c shows the shortfall of generation during the hour of the week of February 14, 2021 with the highest deficit in reserves. There were over 26,200 MW of forced thermal (i.e., natural gas, coal, nuclear, biomass) power plant outages, over 2.5 times the assumed worst case in any SARA report scenario.

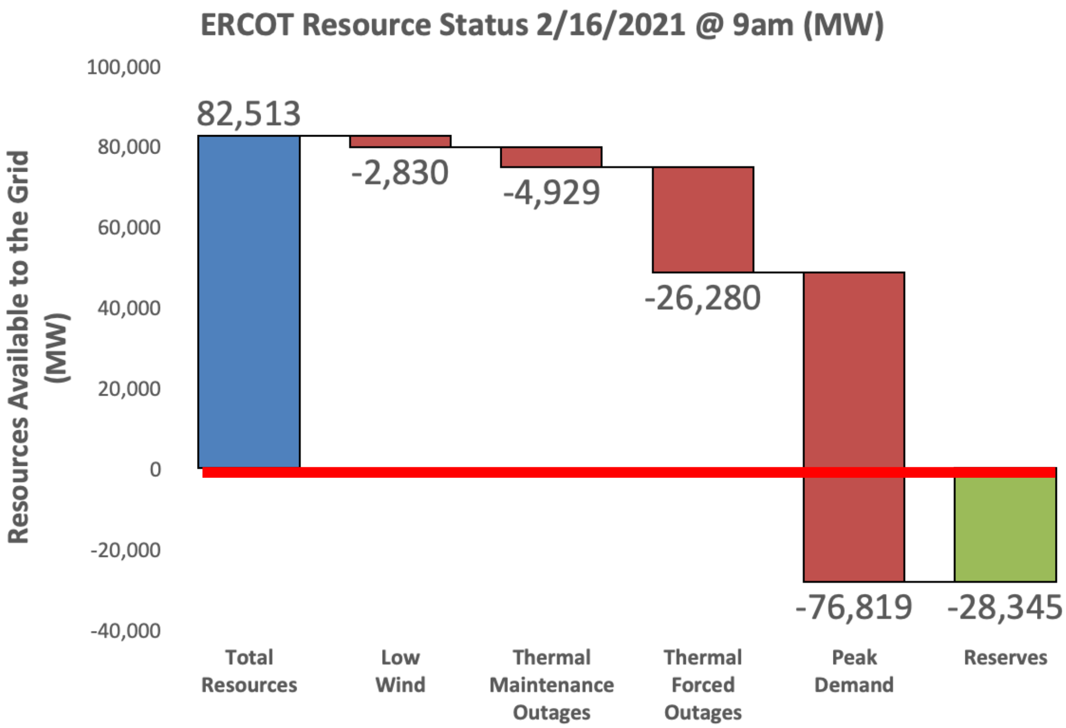


Figure 2.c. Waterfall chart of the actual resource availability at the time of peak demand (February 16, 2021 at 9 am) indicating a shortage of 28,345 MW in capacity due to lower than forecasted wind output, a higher capacity offline for maintenance, and over 26,000 MW of capacity triggered offline as instigated by the weather conditions.[14]

2.2. The Week Before Winter Storm Uri

2.2.1. Weather and Load Forecasts and Alerts

At the end of January, internal discussions between ERCOT's meteorologist and various planning groups began about a potential February cold weather event.[15] However, it wasn't until February 8 that the weather models used by the ERCOT staff began to show a worrisome event for the ERCOT service region. There is inherent uncertainty in the ability of weather models to forecast the timing and severity of extreme cold weather events, such as a polar vortex – even when it is known to be present in North America. As late as February 13, weather models used by ERCOT still disagreed on forecasted morning cold temperatures in Texas cities by as much as 10°F.

The discussion from the National Weather Service Houston/Galveston office provides a summary of the widespread nature of the winter storm.[16] The meteorological events unfolded as follows: A cold front moved in February 10, followed by a winter

[14] The terms "Low Wind," "Thermal Maintenance Outages," and "Thermal Forced Outage" relate to those used in the Winter 2020/2021 ERCOT SARA report.

[15] We summarize these internal ERCOT weather-related communications in the Appendix.

[16] Available at https://www.weather.gov/hgx/2021ValentineStorm

weather advisory (WWA) on February 11, followed by a Winter Storm Watch (WSW) on February 12. From February 13 in the night through February 14, the weather worsened further and the entire state was under a WSW and a Hard Freeze Warning.

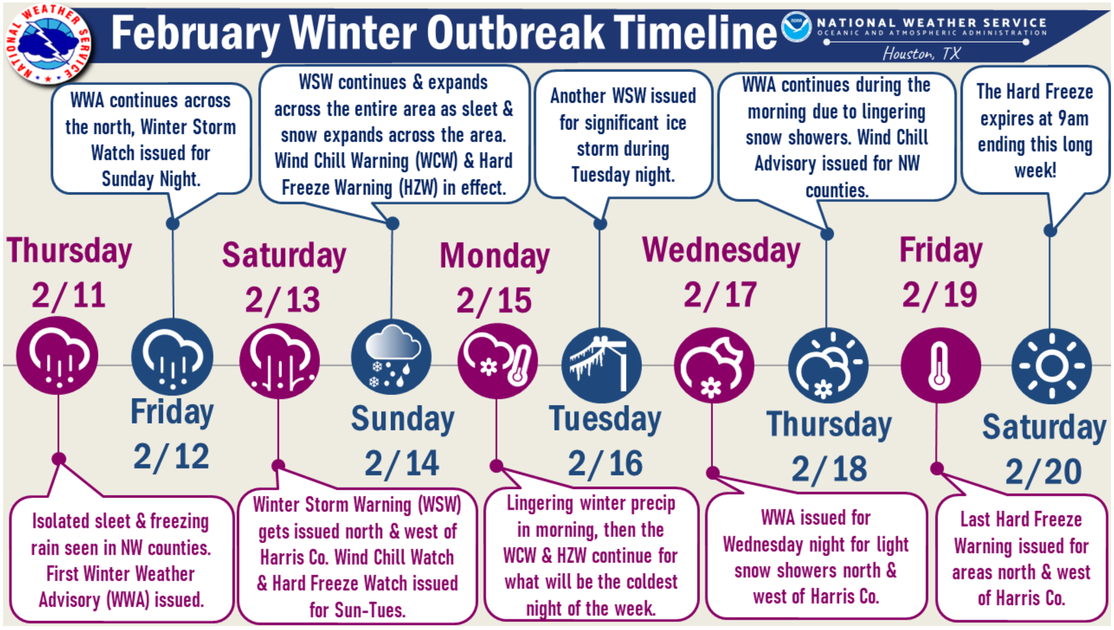


Figure 2.d. Timeline of weather conditions during event

The cold weather experienced was a result of a polar vortex that was impacting temperatures across the U.S. The Dallas/Ft. Worth National Weather Service reported:

> The record cold spell and extended period of wintry weather was caused by the upper-level polar vortex dropping south from the north pole and then lingering over South Central Canada for more than a week. This allowed cold arctic air to gradually spill southward into Texas. At the same time, several upper-level disturbances riding the jet stream moved through the area providing lift and moisture for winter precipitation. These disturbances show up as waves or dips in the lines that move in from the west. Ahead of each wave, upper-level lift increases and moisture is drawn up from the south. Since it was already so cold, this precipitation fell as snow, sleet, and freezing rain.[17]

Since the event was due to an evolving vortex situation, the meteorological community could provide warnings related to unusually cold temperatures towards the end of January. For example, on February 3, CNN's headline was "Every US State

---

[17] https://www.weather.gov/fwd/Feb-2021-WinterEvent.

will see below freezing temperatures over the next week," and mentioned "It's about to get so cold that boiling water will flash freeze, frostbite could occur within 30 minutes and it will become a shock to the system for even those who are used to the toughest winters."[18]

This nature of advance warning (from 7 to 14 days ahead of the event) is unusual. However, the southward migration of the polar vortex was being monitored and predicted by different weather forecast modeling systems in early January. The Washington Post had a report on January 5 titled "The polar vortex is splitting in two, which may lead to weeks of wild winter weather."[19]

In hindsight, while it is apparent that concerns regarding unusually cold winter events were flashing, it is important to note that the system inherently is difficult to predict. The same article highlights that: "The United States is slightly more of a winter wild card for now, experts say, with individual winter storms tough to predict beyond a few days in advance."

ERCOT's first Operating Conditions Notice[20] mentioning the approaching winter storm was on February 8, 2021 – a week before the first of the blackouts began. The notice asked generators to update their ability to provide power and review fuel supplies:

> At 18:53 [February 8, 2021], ERCOT is issuing an OCN for an extreme cold weather system approaching Thursday, February 11, 2021 through Monday, February 15, 2021 with temperatures anticipated to remain 32°F or below. QSEs are instructed to: Update COPs and HSLs when conditions change as soon [as] practicable, Review fuel supplies, prepare to preserve fuel to best serve peak load, and 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. Notify ERCOT of any changes or conditions that could affect system reliability.[21]

ERCOT subsequently issued both an extreme cold weather event advisory and a watch on February 10 and 11, respectively. On February 12, the Texas Governor declared a state of emergency due to the severity of the winter storm.[22]

---

[18] https://www.cnn.com/2021/02/02/weather/polar-vortex-forecast-freezing-cold/index.html

[19] https://www.washingtonpost.com/weather/2021/01/05/polar-vortex-split-cold-snow/

[20] http://www.ercot.com/services/comm/mkt_notices/opsmessages/2021/02

[21] See ERCOT glossary: http://www.ercot.com/glossary. QSE: Qualified Scheduling Entity. COP: Current Operating Plan. HSL: High Sustainable Limit. OCN: Operating Condition Notice

[22] https://gov.texas.gov/uploads/files/press/DISASTER_severe_weather_FINAL_02-12-2021.pdf

On February 10th, as cold temperatures entered the ERCOT region, the total amount of offline power plant capacity increased from 14,400 MW to 25,850 MW, or about 12% to 21% of the total 123,050 MW of installed nameplate capacity in ERCOT. The term nameplate capacity refers to the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.[23] Nameplate capacity is different than the power output one expects from any given generation unit on average or at any given time when it operates in concert with all generation units in an electric grid.

Wind turbines suffered some of the earliest outages and derates as freezing precipitation and fog resulted in ice accumulation on blades and – eventually, as temperatures dropped further – in the gearboxes and nacelles. Unit-specific data indicate that other types of generators – mostly those fueled with natural gas – were facing pre-blackout fuel supply issues, and were starting to go offline or derate capacity as early as February 10 due to fuel delivery curtailments.

Because load projections are based on weather forecasts, uncertainty about the weather meant that ERCOT's load forecasts did not fully anticipate the spike in electricity demand that would result from the winter storm. As the winter event drew closer and its magnitude became clearer, forecast accuracy improved considerably.[24]

Figure 2.e depicts the hourly forecasts released to the market on February 8, 10, 12, and 14 for the ensuing seven days. For example, the forecast released at 8:30 a.m. on February 8 projected total system demand of 58,728 MW for 8 a.m. on February 15. ERCOT estimated that the actual demand would have been 75,573 MW had there been no load shed during that hour.[25] The forecast released on February 14 was considerably more accurate, though it remained 3,540 MW too low.

Figure 2.f shows the forecast error using ERCOT's estimate of the load had there been no load shed minus the forecasts released to the market at 8:30 a.m. on February 11, 12, 13, and 14 – a measure of how well ERCOT's load forecasts predicted the coming demand on the system. Forecasted electrical demands for the late night/early morning hours were the least accurate.

---

[23] Energy Information Adminstration glossary definition of nameplate capacity: https://www.eia.gov/tools/glossary/index.php?id=G#gen_nameplate.

[24] Recent load forecasts are available at: www.ercot.com/gridinfo. An archive of past load forecasts was provided by ERCOT for the purpose of this analysis.

[25] http://www.ercot.com/content/wcm/lists/227689/Available_Generation_and_Estimated_Load_without_Load_Shed_Data.xlsx

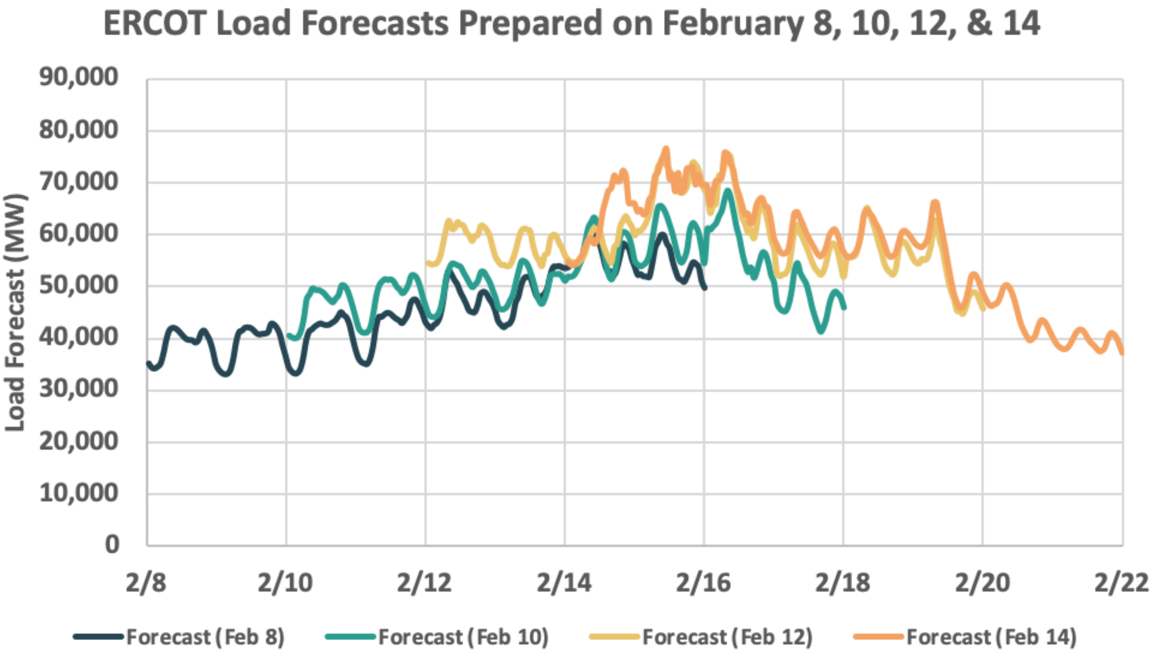


Figure 2.e. ERCOT 7-day (hourly resolution) load forecasts for February 8, 10, 12, and 14.

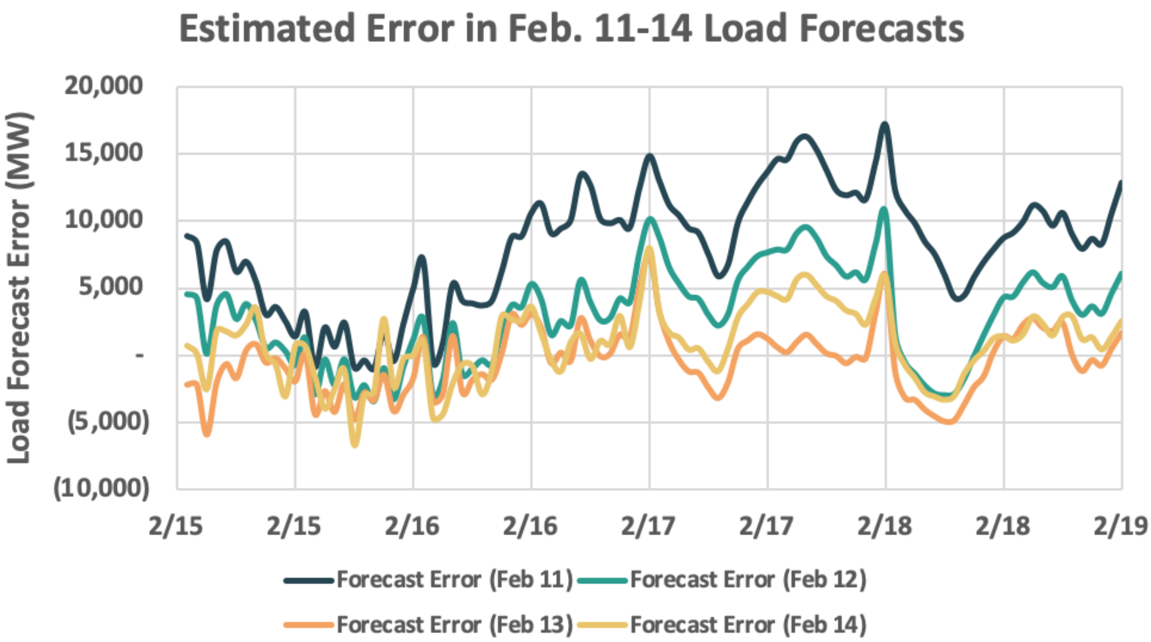


Figure 2.f. The error in ERCOT 7-day (hourly resolution) load forecasts made on February 11, 12, 13, and 14 compared to actual demand on the days of February 15-18, 2021.[26]

[26] Positive values represent the errors (in MW) of forecasts that were lower than actual demand.

The load forecasting error can be at least partially explained by errors in the weather forecasts upon which the electricity demand forecasts were based. Figure 2.g and Figure 2.h depict hourly temperature forecasts, for two of eight ERCOT weather zones, upon which the demand projections in Figure 2.e were presumably based.[27] The North Central zone includes Dallas and Fort Worth, while the South Central zone includes San Antonio and Austin.[28]

The forecast available to ERCOT on February 8 anticipated a low in North Central Texas of 20.5^{o}F at 4:00 a.m. on February 14, for the entire week of the winter event. The February 12 forecast was updated, and it was expected that the region would experience a low 20 degrees colder at just 0.5^{o}F at 6:00 a.m. on February 16.

The data for South Central Texas show a similar pattern. The February 8 forecast showed a low of 26^{o}F at 4:00 a.m. on February 14, for the entire week of the winter event. By February 12, a low of 9^{o}F was expected in the region at 5:00 a.m. on February 16.

[27] Temperature data are available in the Market Information page on www.ercot.com. An archive of the "Weather Assumptions" file was obtained from ERCOT for this analysis.

[28] Note that ERCOT uses data from 29 weather stations. Each zone includes two or three weather stations. Thus, the temperature data discussed here do not correspond with a single weather station.

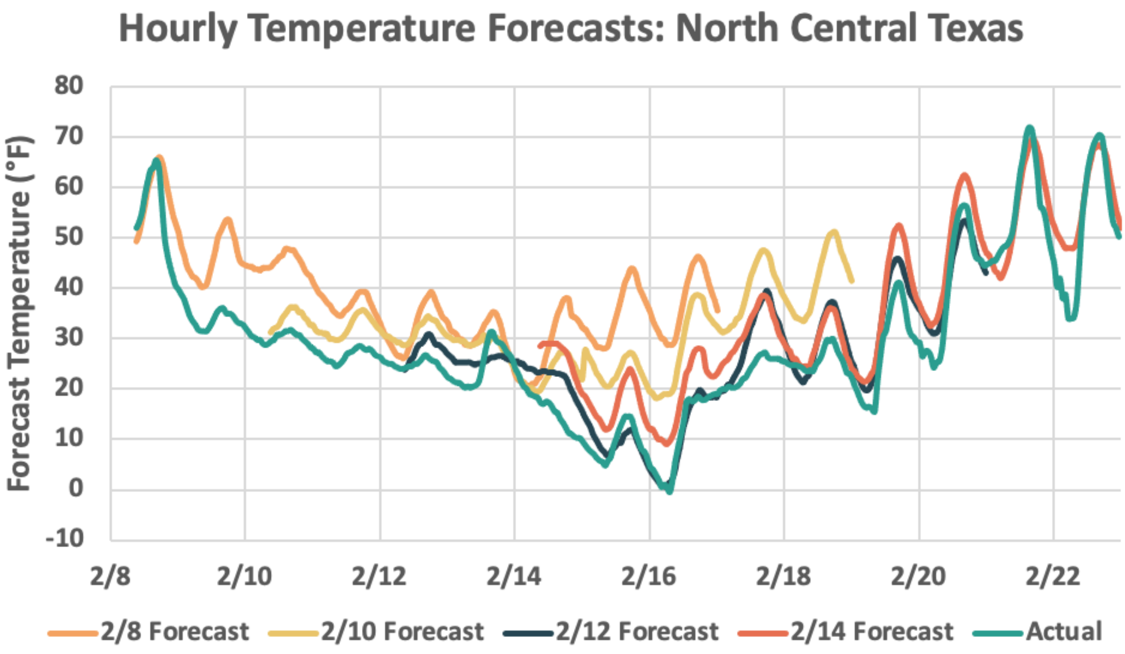


Figure 2.g. Temperature forecasts, as used by ERCOT, for the North Central Texas load region as of the mornings of February 8, 10, 12, and 14. Also shown are the ERCOT staff's calculations of the actual temperatures in the region.

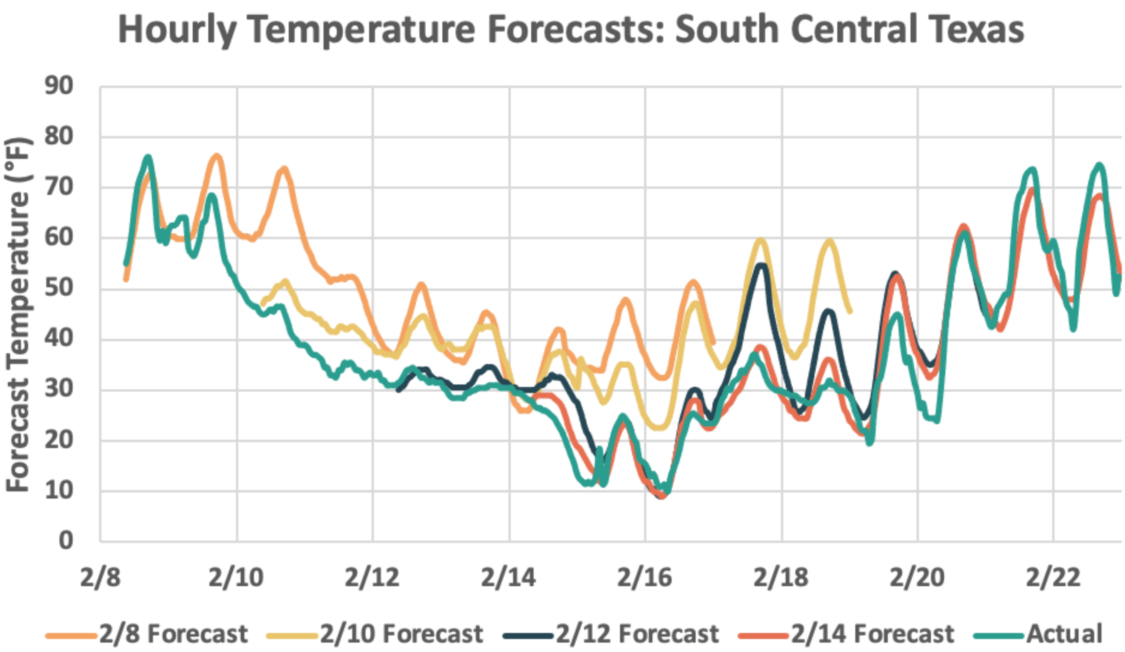


Figure 2.h. Temperature forecasts, as used by ERCOT, for the South-Central Texas load region as of the mornings of February 8, 10, 12, and 14 along with actual temperatures. Also shown are the ERCOT staff's calculations of the actual temperatures in the region.

2.2.2. Recall of Power Plant Outages for Maintenance

At the time (February 8) of ERCOT's first Operating Condition Notice, approximately 6,630 MW of thermal generation were offline for planned maintenance, corresponding to 2,550 MW above the level assumed in SARA scenario "Forecasted Season Peak Load." By the end of Sunday, February 14, about 1,700 MW of generation had been brought back online from either finished or cancelled maintenance, bringing the total planned outage value to 4,930 MW, about 900 MW higher than in the "Forecasted Season Peak Load" SARA scenario (Figure 2.a).

2.3. The Week of Winter Storm Uri (February 13-20, 2021)

On Saturday, February 13 ERCOT began to deploy Responsive Reserves[29] and issued an Emergency Notice for the extreme cold weather event impacting the region. February 13 was also the first day that large generators began to unexpectedly go offline. On Sunday, February 14, ERCOT issued a public appeal for energy conservation and issued multiple watches regarding power supply shortages (Figure 2.i).

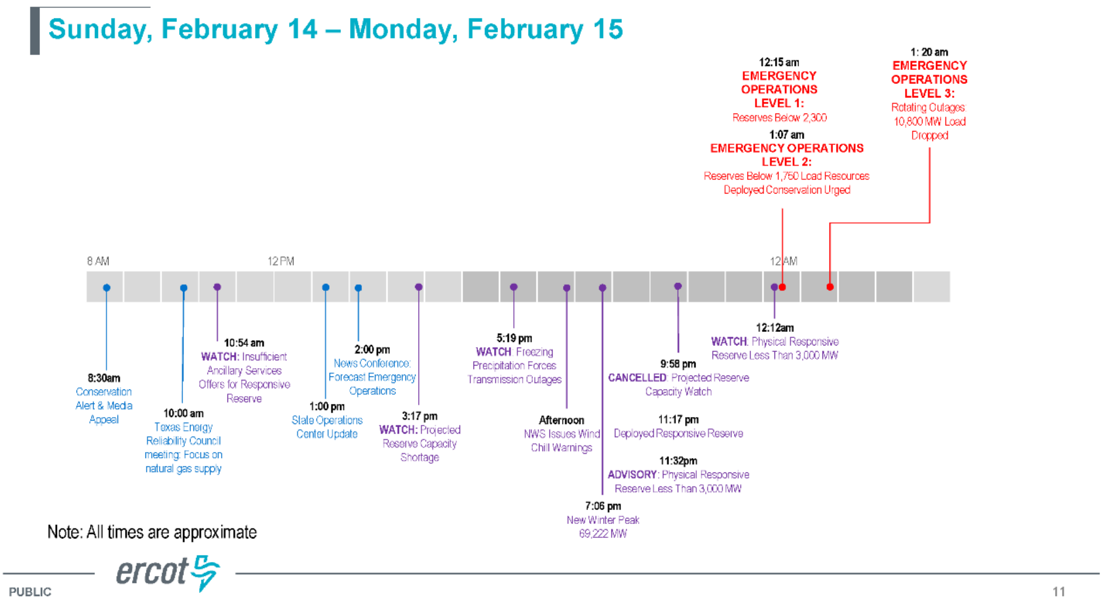


Figure 2.i. ERCOT communications and triggers of Energy Emergency Alerts in the hours leading up to the major load shedding events of the night of February 14 and early morning of February 15, 2021 (ERCOT, 2021).

During the late hours of February 14, electricity load, or demand, was approaching available generation. As generation could not sufficiently increase to meet demand,

[29] Responsive Reserves are an Ancillary Service that provides operating reserves that is intended to: 1) arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT Transmission Grid using Primary Frequency Response and interruptible Load; 2) after the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal; 3) provide energy or continued interruption of load during the implementation of the EEA; and 4) provide backup regulation.

the frequency of the grid began to decline.[30,31] In such circumstances, ERCOT begins various contingency plans such as calling on reserves and shedding load, and at low enough frequencies, automated load shed can occur.[32,33]

On Monday, February 15 at 00:15 CST, ERCOT declared an Energy Emergency Alert Level 1 (EEA 1), at 01:07 CST ERCOT moved to EEA 2,[34] and at 01:20 CST, ERCOT declared an EEA 3 event and began "firm load shed" or "blackouts."[35] ERCOT did not return to normal operations until 10:36 CST Friday, February 19. The ERCOT system frequency reached a low of 59.302 Hz at roughly 1:55am on February 15, 2021.

It is important to note that ERCOT protocols 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 (Table 2.a). This automatic shutdown lowers the risk of exposure to harmful vibrations and heat that can damage generation equipment if operating at low frequency for too long.[36] The ERCOT system frequency dropped below 59.4 Hz for 4 minutes and 23 seconds (Figure 2.j) on the morning of February 15. Consequently, the grid was within minutes of a much more serious and potentially complete blackout on the morning of February 15.

---

[30] Electric grids operate using the principle known as alternating current, or AC. North American grids, including ERCOT, are designed for current and voltage to oscillate at a frequency of 60 cycles per second, or 60 Hz.

[31] If grid frequency falls below 59.9 Hz, this generally indicates that load is large relative to demand.

[32] ERCOT Nodal Operating guide, June 15, 2019 Section (http://www.ercot.com/content/wcm/libraries/182971/June_15__2019_Nodal_Operating_Guides.pdf) Section 2.6 Requirements for Under-Frequency and Over-Frequency Relaying, 2.6.1 Automatic Firm Load Shedding, paragraph (1)

[33] Importantly, ERCOT makes other non-automated (by engineering devices) decisions to trigger actions to stabilize the grid before grid frequency reaches 59.3 Hz (e.g., call on responsive reserve and non-spinning reserve capacity).

[34] See ERCOT glossary: http://www.ercot.com/glossary. EEA: Energy Emergency Alert

[35] http://www.ercot.com/services/comm/mkt_notices/opsmessages/2021/02

[36] About 1,800 MW of (mostly coal and natural gas) generators listed frequency issues as the reason for tripping offline during the winter event, even though, according to ERCOT protocols (Table 2.a of this report), the frequency deviation shouldn't have tripped any under-frequency relays that are designed to automatically disconnect the power plant from the grid to physically protect itself. However, at some power plants, rapid increases in exhaust and boiler pressures occurred from equipment responding to grid frequency changes. Those fluctuating power plant conditions in turn tripped other safety mechanisms that took generators offline. Some large thermal generation units require days to fully cool off before they can be restarted.

Table 2.a. Table from Section 2.6.2 of ERCOT Nodal Protocols indicating the allowed settings for under-frequency relays installed on Generation Resources.[37]

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

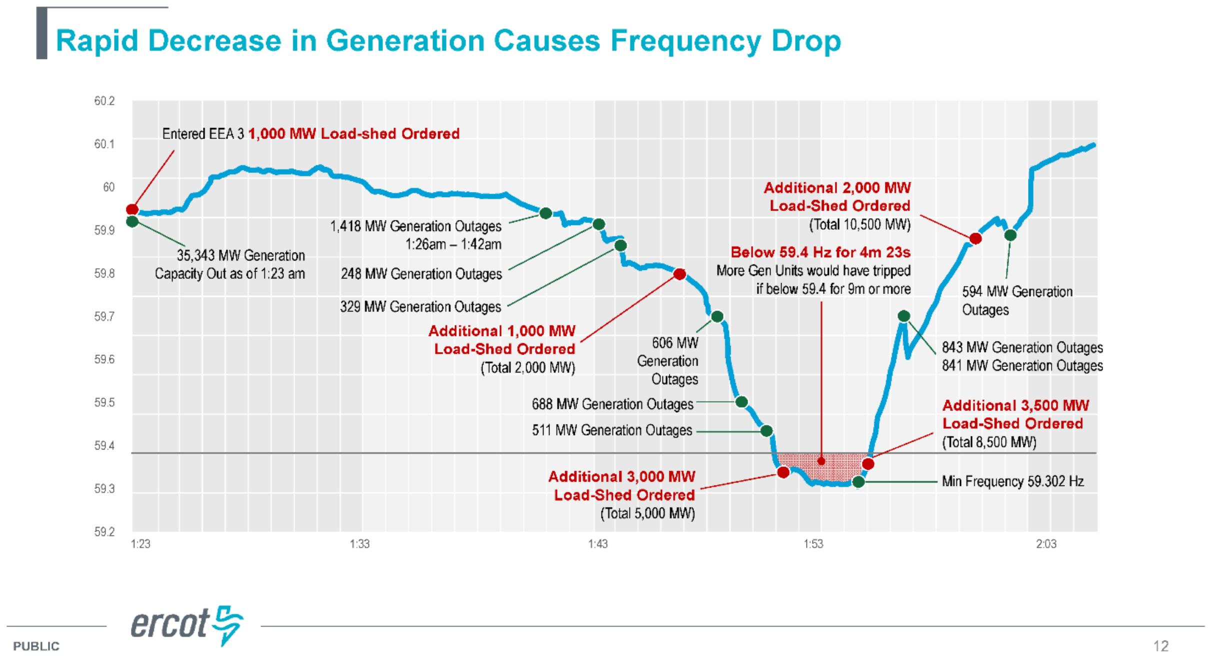


Figure 2.j. The ERCOT grid frequency during the critical time of load shedding and generation capacity outages on the morning of February 15, 2021 (ERCOT, 2021).

Figure 2.k shows the high level status of the grid from February 12 to February 20, including what load would have been absent blackouts, the actual served load, total renewable and thermal (nameplate) outages, as well as the level of load shed (blackouts).

[37] Note that we are presenting certain figures that were created by the ERCOT staff in this document, in situations where have been able to review and confirm the underlying data used in the creation of those figures.

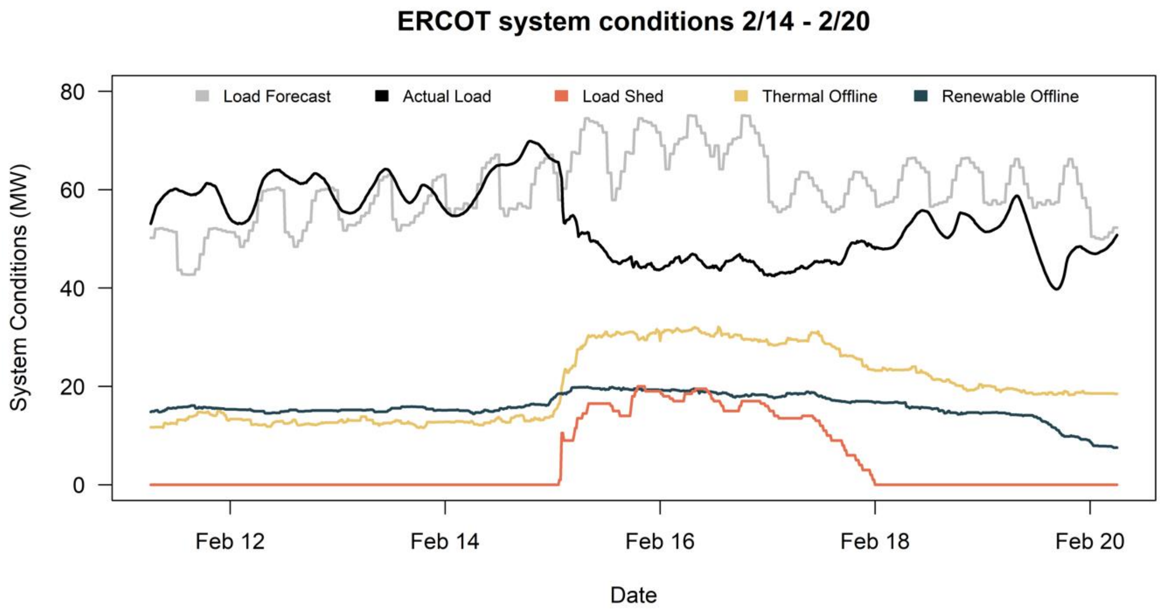


Figure 2.k. Hourly time sequence of forecasted load, actual load, and power plant capacity offline from Feb 11-19, 2021.[38]

Absent load shed, ERCOT back casted demand to peak at roughly 76,800 MW,[39] about 19,120 MW higher than the value expected under normal winter weather (57,699 MW) and more than 9,500 MW higher than ERCOT's "Extreme Peak Load" SARA scenario.[40] However, not only was demand underestimated, but supply was overestimated, as discussed in the following section.

2.4. Generation Outages (Timeline)

ERCOT has publicly released data regarding which power plants went offline and when[41] and also aggregated capacity that was offline by cause of outage as categorized (largely) by power plant operators.[42]

---

[38] Data from ERCOT's hourly load data archives as well as various public reports and datasets provided by ERCOT. See http://www.ercot.com/news/february2021.

[39] http://www.ercot.com/content/wcm/lists/227689/Available_Generation_and_Estimated_Load_without_Load_Shed_Data.xlsx

[40] http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.xlsx

[41] http://www.ercot.com/content/wcm/lists/226521/Unit_Outage_Data_20210312.xlsx.

[42] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

Going into the early morning of February 15, generation outages (nameplate) were already high at roughly 30,000 MW. By 9:00 a.m., total outages and derates[43] increased to over 50,000 MW, or roughly 40% of the total installed nameplate capacity in ERCOT. Levels of outages and derates would change over the event, but would not return to pre-blackout levels until the afternoon of February 19. Figure 2.l shows outages and derates of power plants by cause (as reported to ERCOT by generators, with some possible interpretation by ERCOT), based on nameplate capacity.

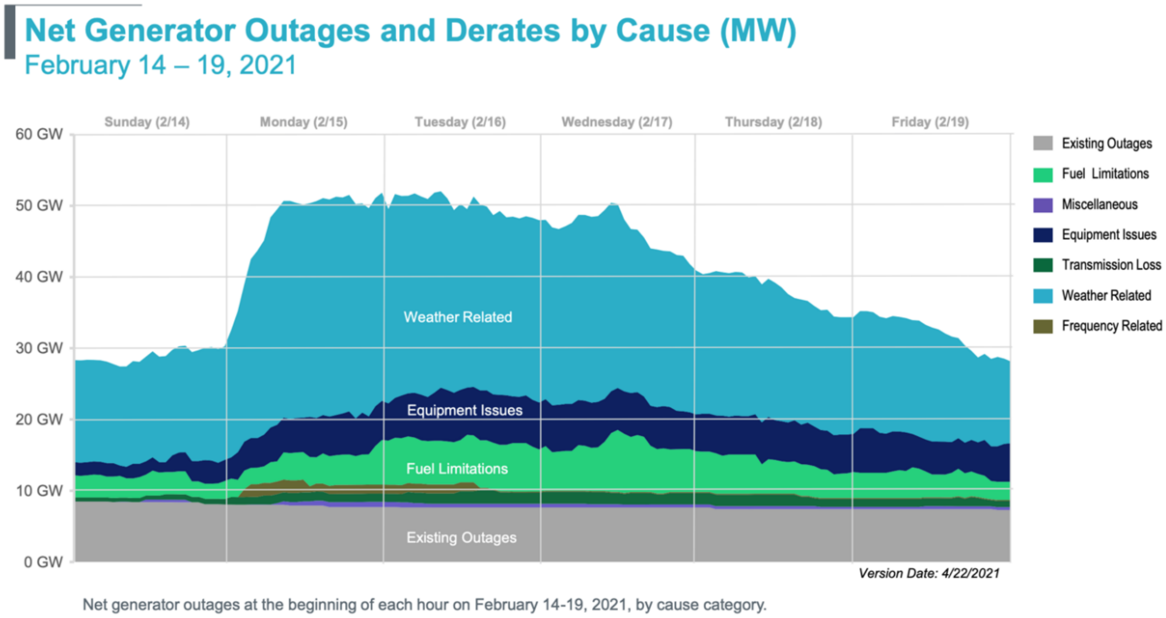


Figure 2.l. Net capacity outages and derates by category of failure mode, when considering the rated nameplate capacity of all power plants. Figure by ERCOT.[44]

As the extreme cold weather settled over the entire state, the outages increased. From noon on February 14 to noon on February 15, the offline renewable capacity increased from 15,100 MW to 19,400 MW (+4,300 MW) and the total outages of thermal generators increased from 13,700 MW to 31,100 MW (+17,400).[45]

Figure 2.m shows the spatial temperature and generation outages across Texasduring the critical hour when grid frequency was declining on the early morning of February 15, and the time of peak generation capacity outages on February 16.[46] As the

---

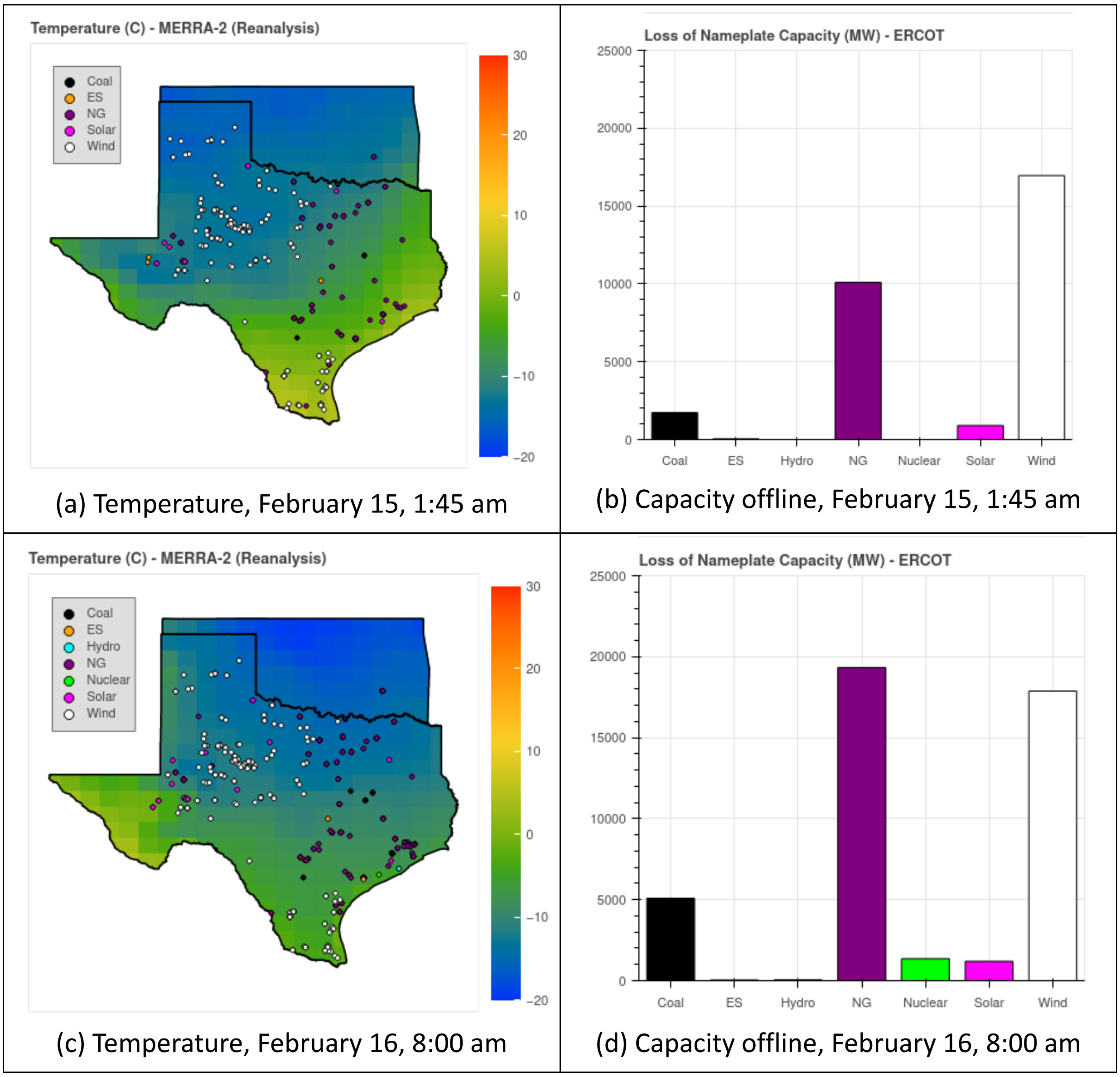
[43] A derated power plant is one that is able to produce some level of power output, but it not able to produce at its full potential. For example, some natural gas power plants weren't able to get enough gas to run at 100% output, but were still able to produce some power at a lower level, thus the power plant was derated.

[44] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf

[45] Values rounded to nearest 100 MW.

[46] Temperature data come from the National Atmospheric and Space Administration (NASA) Modern-Era Retrospective Analysis for Research and Applications, Version 2 (MERRA-2): https://goldsmr4.gesdisc.eosdis.nasa.gov/data/MERRA2/.

colder temperatures moved further south into Texas, so did generation outages. Moreover, the types of outages changed.



(a) Temperature, February 15, 1:45 am

(b) Capacity offline, February 15, 1:45 am

(c) Temperature, February 16, 8:00 am

(d) Capacity offline, February 16, 8:00 am

Figure 2.m. The temperature across Texas and reported loss of (nameplate) capacity by ERCOT for the critical time period of February 15, 1:45 am (a and b) and the time of peak generation outage on February 16, 8:00 am (c and d).[47]

Generator outage data, as reported to and summarized by ERCOT, suggest that the largest share of outages was weather-related. The capacity that went offline due to weather-related[48] causes doubled from 15,000 MW at noon on February 14 to

[47] Each circle in subfigures (a) and (c) indicates the location of power generation units that are offline or derated, and its color corresponds to the capacity in subfigures (b) and (d). Temperature data come from the MERRA2 reanalysis data set.

[48] ERCOT defines outages which are weather-related in the following manner: “This includes but is not limited to frozen equipment—including frozen sensing lines, frozen water lines, and frozen valves—ice accumulation on wind turbine blades, ice/snow cover on solar panels, exceedances of low temperature limits for wind turbines, and flooded equipment due to ice/snow melt.”

30,000 MW at noon on February 15. In total, about 167 units listed their outages as weather-related during the event. Beyond wind turbine icing, outages between February 14 and 15 were mainly the result of frozen water intakes and sensing lines and the freezing of other general equipment. As freezing weather persisted further, other problems arose — for example, there were issues around control and condensate systems that caused more capacity to go offline. At least two black start-rated units reported outages or derates for weather-related reasons. [49]

The second largest reported category of offline capacity was existing outages, including scheduled and planned outages, mothballed units, and forced outages that started before the February 8 OCN. At noon on February 14 approximately 8,400 MW of capacity was offline due to existing outages. The majority of this capacity (7,700 MW) was from coal and natural gas power plants. The total amount of these pre-existing outages steadily declined to 7,300 MW by the end of the event.

"Equipment issues" accounted for the third highest amount of power plant outages and derates. Equipment issues were the cause of 1,900 MW of outages at noon on February 14, rising to 5,600 MW by noon on February 15. In total, equipment issues were listed as the reason for outages at about 146 units. A survey of unit-specific outage data indicates that these power plants went offline because of equipment failures that were not directly associated with the weather, for example clogged sensing lines and stuck valves due to normal wear and tear.[50] At least six black start-rated units reported outages or derates based on equipment failures.

Fuel limitations account for the fourth-most capacity outage and derating, with 131 units listing this reason for their outage.[51] Fuel limitations mostly affected natural gas plants and coal plants. Fuel issues for natural gas existed before the blackouts began (3,500 MW at noon on February 14) and increased as the event continued (6,700 MW at 10:00 a.m. on February 17). While there were no fuel-related outages associated with coal on February 14, issues appeared on February 15 and caused the outage of a maximum of 2,100 MW at 4:00 p.m. on February 16. Lack of fuel, low fuel pressure,[52] and fuel contamination were the major listed reasons for fuel-related outages for natural gas-fired generation units. Detailed, unit-specific, power plant outage information indicates that power plants with both "firm" and "non-firm" fuel

[49] Black start generation units are those able to start generation on their own, without support of the ERCOT transmission grid, as if there was absolutely no electricity generation on the grid (i.e., the grid is off, or "black" with no lights).

[50] Equipment failures such as these also happen in the summer when older power plants that don't run often are pressed into service to meet peak demand.

[51] Fuel limitation issues later matched or exceeded equipment issues by February 16.

[52] Some power plants were able to derate with lower fuel pressures, but others had to turn off completely.

supply contracts experienced fuel supply/curtailment issues. Also, at least five black-start-rated units reported outages or derates based on fuel supply issues.

Generator reports to ERCOT indicate that natural gas fuel shortages preceded the firm load shed directives from ERCOT, occurring as early as February 10. These fuel limitations affected more generation capacity as the cold weather event continued. At least as early as February 8, ERCOT began notifying QSEs of potential weather issues and instructed them to notify ERCOT of any known or anticipated fuel restrictions. ERCOT has an arrangement with at least one natural gas supplier to provide e-mail notifications when gas supply restrictions are issued to its natural gas-fired electric generation facilities. ERCOT received such notices as early as February 9 for supply restrictions starting the morning of February 10. Additionally, ERCOT received a notice on February 10 of supply restrictions for parts of Texas that would completely cut off power plants from fuel delivery and would start on February 12.

Additional natural gas outages are potentially due to the loss of electricity affecting the ability of the natural gas infrastructure to operate and thus deliver fuel, but we did not have data to evaluate the magnitude of this interdependence, or determine causality. Public testimony from Oncor's CEO indicated that not all infrastructure that was critical to the natural gas supply chain was registered with them as critical load not to be turned off.[53] He stated that Oncor started the event with 35 pieces of critical natural gas infrastructure on their "do not turn off" list, but added 168 more by the end of the event. This presumably indicates that some delivery of natural gas may have been interrupted due to power outages because the operators of the critical natural gas infrastructure failed to alert the transmission and/or distribution providers (TDSPs)[54] that they were critical loads.

The detailed outage data also suggest that transmission and substation outages led to generation outages reaching 1,900 MW of wind and solar on February 16. No coal, natural gas, or nuclear generation units listed transmission outage as a reason for an outage or derate. In all, 18 solar and wind units listed transmission losses as their reason for outage or derating. Additional data from ERCOT indicate that on February 9 the grid operator identified 28 existing transmission outages that could be cancelled or withdrawn by February 12, and all outages planned to begin between February 12-17 were moved, cancelled, or withdrawn. While it is likely that the grid could have operated in a more stable manner with fewer planned transmission outages, it is unknown how much worse, if at all, the situation would have been had these outages been allowed to proceed.

---

[53] https://www.texastribune.org/2021/03/18/texas-winter-storm-blackouts-paperwork/.

[54] Section 2 of ERCOT protocols defines Transmission and/or Distribution Service Provider as: "An Entity that is a TSP, a DSP or both, or an Entity that has been selected to own and operate Transmission Facilities and has a PUCT approved code of conduct in accordance with P.U.C. SUBST. R. 25.272, Code of Conduct for Electric Utilities and Their Affiliates." DSP = distribution service provider.

Grid frequency deviations were reported to be responsible for up to 1,800 MW of outages (8 total units), mostly coal, at 2 a.m. on February 15.

Figure 2.n aggregates all the causes of outages and shows the total amount of outages by fuel, based on nameplate capacity. From noon on February 14 to noon on February 15, the amount of offline wind capacity increased from 14,600 MW to 18,300 MW (+3,700 MW).[55] Offline natural gas capacity increased from 12,000 MW to 25,000 MW (+13,000 MW). Offline coal capacity increased from 1,500 MW to 4,500 MW (+3,000 MW). Offline nuclear capacity increased from 0 MW to 1,300 MW, and offline solar capacity increased from 500 MW to 1100 MW (+600 MW).

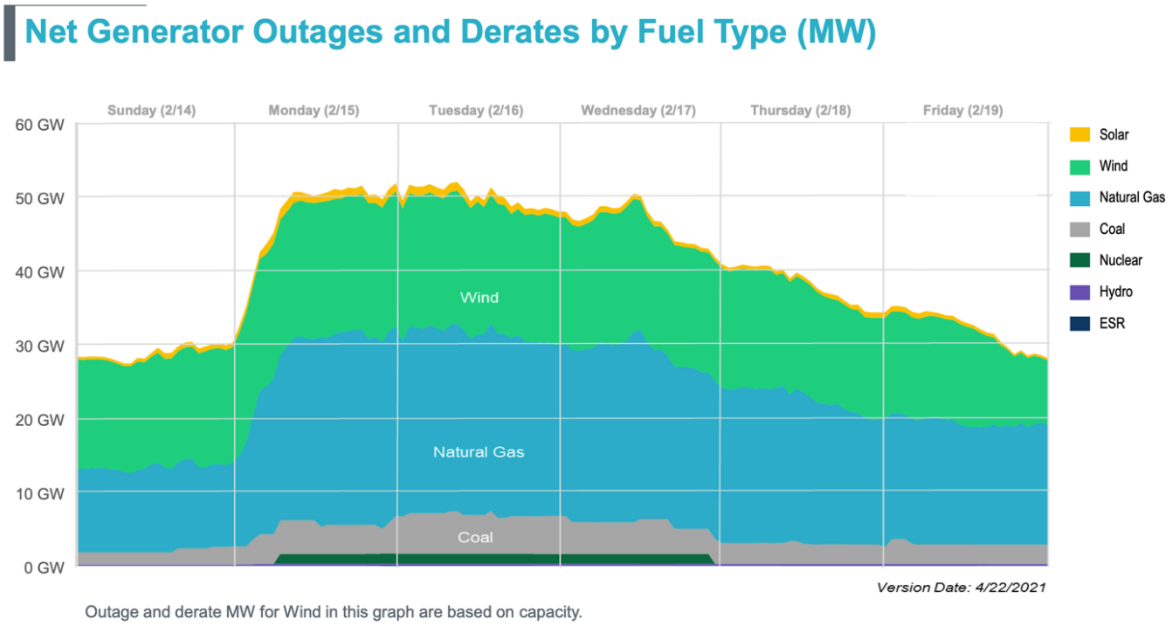


Figure 2.n. Net capacity outages and derates by fuel type, relative to the rated nameplate capacity of all power plants. Figure by ERCOT.[56]

Since rated nameplate capacities of wind and solar plants refer to the maximum amount of generation possible, derates based on these capacities overstate the amount of lost power generation due to the winter storm. Figure 2.o accounts for this by showing the same information as Figure 2.n based on the wind and solar capacities that would have been available based on back casted modeling that uses actual wind speed and solar radiation data to estimate what would have been

---

[55] Nameplate capacity for wind and solar is not representative of the amount of power generation expected when the unit is not expiериencing an outage, but is much closer for the thermal fleet. When accounting for backcasted values of the available wind and solar radiation, available wind capacity outages actually decreased from 9,070 MW to 5,020 MW (-4,050) over the same time period and solar outages increased less from 108 MW to 545 MW (+437 MW).

[56] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

produced had all of the available wind and solar capacity been online.

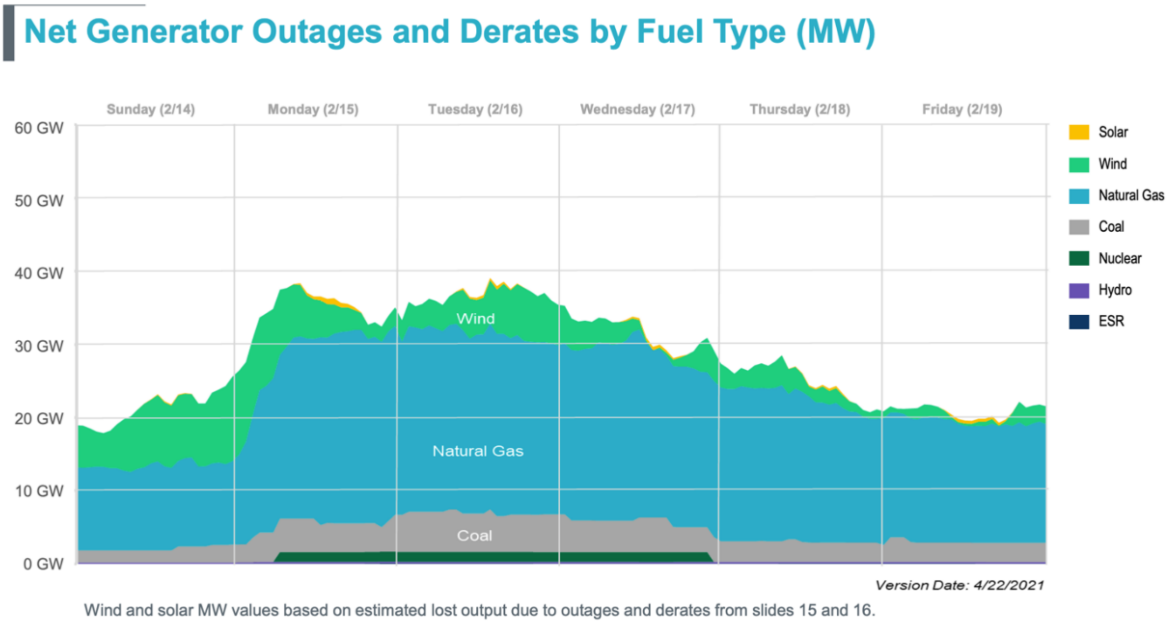


Figure 2.o. Net capacity outages and derates by fuel type, relative to expected contribution from wind and solar. Since wind and solar are not expected to generate at their nameplate capacity rating, the value derating shown here is less than that for wind and solar in Figure 2.n. Figure by ERCOT.[57]

Prior to the event, the Department of Energy and the Texas Commission on Environmental Quality issued directives to ERCOT that allowed the grid operator to dispatch certain power plants even if they would exceed pollution limits. The grid operator calculated that these directives enabled additional generation units to contribute an additional 1,400 MW of capacity, subject to outages and derates.

2.4.1. Generator Temperature Ratings Relative to Experienced Temperatures

This section combines data from ERCOT's public file of generator outages released on March 12, 2021 with weather data and confidential temperature ratings of power plants.[58] The purpose is to provide a high level view of whether some power plants failed above or below their low temperature ratings (see Figure 2.p). This section is not meant to provide a fully rigorous analysis of power plant failures as we only compare temperatures and not, for example, the enhanced cooling effects of wind,

[57] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

[58] For power plants that experienced an outage during the event, ERCOT sent Requests for Information (RFIs) to assess their causes. These RFIs included the question: "What is the minimum ambient operating temperature that the unit can start and continue to run without a unit trip or derate?" Some generators responded with "Unspecified" or "Unknown", but some were able to provide the minimum operating temperature, by unit, which were used here for comparison.

humidity, or ice. Also, *we only plot data for a subset* of the power plants listed in ERCOT's public file of generator outages.

The weather data are from the National Atmospheric and Space Administration (NASA) Modern-Era Retrospective Analysis for Research and Applications, Version 2 (MERRA-2) database. The MERRA-2 reanalysis weather database consists of atmospheric reanalysis data based on multiple types of historical observations. The data has an hourly time resolution and the reanalysis spans 1980-present. To relate a given power plant to a temperature in the MERRA-2 database, we assume the experienced power plant temperature is the same as the closest MERRA-2 temperature (example temperature distributions by grid cell are in Figure 2.m).[59]

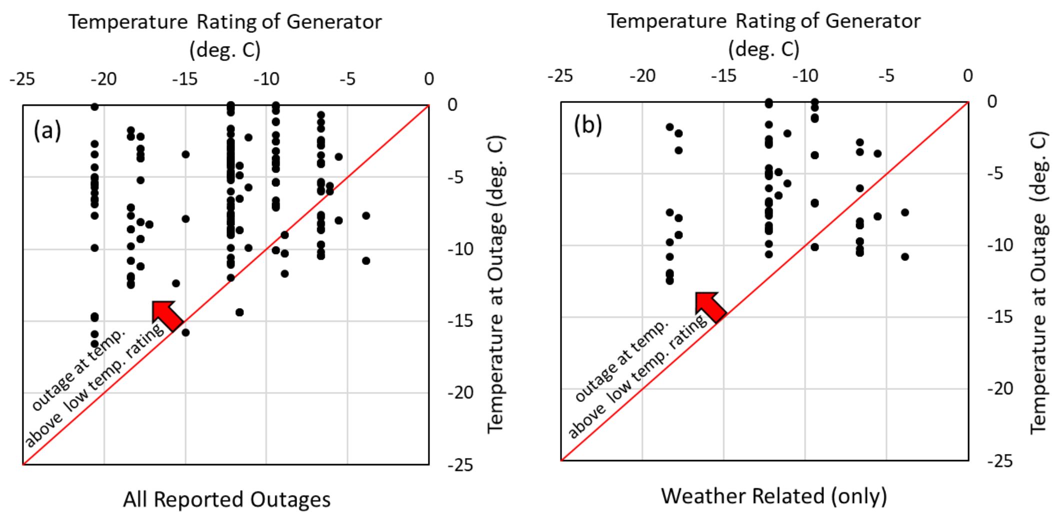


Figure 2.p. Plots of the estimated temperature experienced at outage for a subset of thermal power plants that experienced an outage or derate versus the lowest rated (design) temperature of power generation units (as reported by generation operators to ERCOT and FERC) for the winter event of February 10-20, 2021. We present the data in two charts: (a) generation units experiencing outages for any reason, (b) generation units experiencing outages summarized as "weather related" by ERCOT. Electric generation units were chosen at random.

Each dot in Figure 2.p represents a single generation unit listed in ERCOT's public data file of power plant failures. We include two charts in Figure 2.p, all the power plants that we compared (a) and the subset that reported their outage as being "Weather Related." The red line represents the boundary where the power plant design temperature equals experienced temperature. **A data point above the red line** means that a generation unit experienced an outage or derating at a temperature above its minimum temperature rating. **A data point below the red line** means that a generation unit experienced an outage or derating while experiencing a temperature below its minimum design temperature rating. Thus, in this simple analysis, data

[59] More precisely, the temperature is associated with the centroid of the MERRA-2 0.5° × 0.625° grid with the shortest Euclidean distance to the latitude and longitude of the power plant.

points above the red line indicate that some generation units might not have met their temperature design criteria. [60]

2.5. Load Curtailment, Requested and Achieved

As the freezing temperatures increased demand for electricity-based heating of homes and other buildings, ERCOT, the TDSPs, load-serving entities, and customers undertook a variety of actions to reduce demand on the system during the winter event, including:

- Involuntary load reduction due to selective outages of distribution circuits or substation loads chosen by the TDSPs and directed by Transmission Operators (TO)[61] when ERCOT issues load shed orders.
- Customer response to high market prices by customers exposed to wholesale electricity prices or natural gas prices.
- Deployment of load resources.
- Deployment of ERCOT's Emergency Response Service (ERS) program.
- Automated load shed triggered by under-frequency relays.
- Deployment of various demand response (DR) programs by load-serving entities.

2.5.1. Involuntary Load Shed

Per its Protocols, ERCOT declares an EEA Level 3 if operating reserves cannot be maintained above 1,375 MW. If conditions do not improve, continue to deteriorate, or operating reserves drop below 1,000 MW and are not expected to recover within 30 minutes, ERCOT orders transmission providers to reduce demand on the system.[62] The TDSPs are charged with making the final decision on which circuits to turn off to achieve the demand reduction. Each Transmision Operator (TO) is responsible for a predetermined percentage of the total load shed that ERCOT calls for in its "ERCOT

---

[60] We note a few important caveats for interpreting this figure. The figure does not indicate the minimum temperature actually experienced by any given power plant, which is likely lower than the temperature displayed, but its minimum design temperature and the temperature at which it experienced an outage. Also, the figure has no information about precipitation (rain, ice, snow, fog) which could have been a crucial factor in any given power plant outage or derating. Also, only natural gas, coal, and nuclear generation units are shown in this figure. In particular, most wind power outages related to ice accumulation which was a combination of subfreezing temperatures and precipitation or fog.

[61] A Transmission Operator (TO) is defined in Section 2 of ERCOT protocols as "A Transmission and/or Distribution Service Provider (TDSP) designated by itself or another TDSP for purposes of communicating with ERCOT and taking action to preserve reliability of a particular portion of the ERCOT System, as provided in the ERCOT Protocols or Other Binding Documents."

[62] http://www.ercot.com/content/wcm/lists/200198/EEA_OnePager_updated_9-4-20.pdf

Load Shed Table."[63] Each TO instructs its respective TDSPs to achieve its load shed obligation. The percentage of load reduction for each TO is based on the previous year's peak Loads for its respective Transmission Service Providers (TSP), as reported to ERCOT and modified annually.

EEA Level 3 with Firm Load Shed was called on February 15 at 1:25 CST.[64] Load shed orders increased to 20,000 MW by 19:00 on the February 15. An analysis of load data appears to confirm compliance with the involuntary load reduction instructions.[65]

2.5.2. Response to High Prices

ERCOT conducts surveys of load-serving entities to discern the number of energy consumers under price-sensitive electricity plans. Such plans might include real-time pricing (to directly expose a consumer to wholesale market prices), peak rebate proms (providing a rebate to consumers who reduce demand below baseline amounts at the request of the load-serving entity), or block and index pricing (where consumption in excess of a contractual amount is exposed to market prices, while consumption below that amount results in a credit based on prevailing market prices).

In 2020, over 100,000 accounts were under a real-time pricing or block and index pricing plan. The number of accounts under a peak rebate plan was over 94,000.[66]

In recent summer periods with overall high system peak demand and high electricity prices, ERCOT has estimated demand response based on these accounts to be in excess of 4,000 MW.[67] The amount of demand reduction due to high prices during this winter event is difficult to determine, since many customers lost service due to involuntary outages and for other reasons.

---

[63] This ERCOT Load Shed Table is in Section "4.5.3.4, Load Shed Obligation" of the ERCOT Operating Guide. During February 2021, the language of Section 4.5.3.4 stated: "Obligation for Load shed is by DSP. Load shedding obligations need to be represented by an Entity with 24x7 operations and Hotline communications with ERCOT and control over breakers. Percentages for Level 3 Load shedding will be based on the previous year's TSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually." As of July 1, the language of Section 4.5.3.4 has been amended.

[64] www.ercot.com/services/comm/mkt_notices/notices/2021/02

[65] See slides 4 and 5: http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx.

[66] http://www.ercot.com/content/wcm/key_documents_lists/214087/15._RMS_2020_4CP__Retail_DR_Analysis_Raish.v3.pptx.

[67] http://www.ercot.com/content/wcm/key_documents_lists/218751/DSWG_2020_4CP__Retail_DR_Analysis_Raish.pptx, slide 5.

2.5.3. Deployment of Load Resources

Large industrial energy consumers with the ability to curtail their demand on the ERCOT system are permitted to provide ancillary services. Roughly half of ERCOT's requirements for Responsive Reserve Services (RRS)[68] are met by load resources equipped with under-frequency relays that instantaneously curtail load when the frequency drops to 59.7 Hz. Resources providing this service must also be able to respond to verbal dispatch instructions. In February 2021, the amounts of RRS provided by loads averaged 1,259 MW, which is lower than the 1,548 MW resource provided in January 2021.[69] Some load resources are also eligible to provide Regulation Up,[70] Regulation Down,[71] and Non-Spinning Reserves,[72] though the amount that these services provided in February 2021 was small.[73]

An analysis of load data suggests that maximum load reductions from load resources were over 1,400 MW on February 15, 16, and 17, and just under that level on February 19.[74]

2.5.4. ERS Program

The ERS program was activated during the winter event to reduce demand on the system.[75] Customers enrolled in the program reduce their purchases from the grid by reducing load or by starting backup generators. These emergency resources are contracted to provide this service to ERCOT through four-month contracts, and have response times of 30 minutes or 10 minutes. Different amounts are procured in each of eight time periods (or hour blocks) spread among weekday and weekend days.

---

[68] RRS provides an operating reserve from on-line generation resources that is responsive to frequancy based on governor action and responsive to any automated or verbal dispatch instructions from ERCOT within 10 minutes. Load resources providing RRS respond via underfrequency relays when system frequency drops below 59.7 Hz.

[69] http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13242&reportTitle=Monthly%20ERCOT%20Demand%20Response%20from%20Load%20Resources&showHTMLView=&mimicKey.

[70] Regulation Up provides an operating reserve that increases generation output (or reduces demand, if a load resource) in response to automated signals to balance real-time demand and resources.

[71] Regulation down provides an operating reserve that decreases generation output (or increases demand, if a load resource) in response to automated signals to balance real-time demand and resources.

[72] Non-spinning reserves provides an operating reserve that can be synchronized and ramped to a determined amount of generation or load reduction within 30 minutes of notice.

[73] http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13242&reportTitle=Monthly%20ERCOT%20Demand%20Response%20from%20Load%20Resources&showHTMLView=&mimicKey.

[74] See slide 7 at: http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx.

[75] http://www.ercot.com/services/programs/load/eils

Overall, the program achieved its targeted level of demand reduction of roughly 1,100 MW during the morning of February 15.[76] Some of the energy consumers in the program reduced their level of demand prior to the EEA Level 3 and deployment of ERS, as many businesses closed in anticipation of the storm. Some of the early demand reduction may have also resulted from public appeals for energy conservation, and local transmission and distribution system outages.

While the participating "loads" or consumers in the ERS program provided demand reduction well in excess of their obligations, ERS program participants contracted to provide generation during emergencies generally under-performed. The ERS generators met less than half of their obligation of around 300 MW in the early hours of February 15.[77] Performance of the ERS generators was reportedly hampered by "supply constraints, refueling issues, and forced outages."[78] Some generators in the ERS program indicated that they were not able to meet their requirements because they ran out of fuel (many have enough on-site fuel for only a few hours or days). Other ERS generators indicated that the distribution circuit through which they were served was turned off, so they were not able to provide power to the bulk grid.

2.5.5. Automated Load Shedding via Under-frequency Relays

Under-frequency load shed (UFLS) relays exist on the transmission and distribution grid. These are configured to trigger a circuit offline, and thus the customers on that circuit, if experiencing a frequency of 59.3 Hz or lower. At 59.3 Hz, under-frequency relays on the transmission and distribution grid can trigger automatic load shedding of up to 5% of the transmission operator's load (Table 2.b). Lower frequencies trigger even more UFLS.

Table 2.b. Table from Section 2.6.1 of ERCOT Nodal Operating Guide indicating the settings for Under-Frequency Load Shedding (UFLS) relays installed by Transmission Operators (TO).

Frequency Threshold	TO Load Relief
59.3 Hz	At least 5% of the TO Load
58.9 Hz	A total of at least 15% of the TO Load
58.5 Hz	A total of at least 25% of the TO Load

[76] http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX. Per slide 3: "As an ERS fleet in aggregate, the response generally met or exceeded the aggregate obligation." Note that ERS obligations differ in different time periods within a day.

[77] http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX. Slide 15.

[78] http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX, slide 8.

Confidential responses of TDSPs to ERCOT requests for information note UFLS relay tolerances of +/- 0.01 Hz, and some TDSPs recorded frequencies between 59.300 and 59.310 Hz during the critical frequency period indicated in Figure 2.j. As reported by five of the major TDSPs in ERCOT, the total MW UFLS by automatic (by experiencing low frequency) triggering of relays was on the order of 200 MW for 2 to 3 dozen circuits.

In addition to automated triggering of UFLS relays, the TDSPs also included some circuits with UFLS relays in the so-called manual load shed in which they selected circuits to trip offline to meet their portion of the load shed obligation as commanded by ERCOT. There were over 1000 circuits (possibly more than 2000) with UFLS relays included in this manual load shed. Thus, the manual load shed affected two orders of magnitude more load, number of circuits, and customers than were triggered via automated UFLS. At all times the TDSPs were still required to have 25% of load on circuits with UFLS relays.

2.5.6. Deployment of Various Demand Response (DR) Programs by Load-Serving Entities

Many DR programs are operated by load-serving entities completely outside of ERCOT's formal markets. For example:

- CPS Energy operates a large portfolio of demand response programs that can achieve demand reductions of well over 200 MW during a typical summer deployment.[79]
- Austin Energy operates certain DR programs.[80]
- A number of retail electric providers operate programs that control thermostats to achieve residential demand reduction.[81]

Though the focus of these programs has historically been on reducing demand during the summer, at least one utility attempted to deploy their programs during the winter event to achieve whatever demand reduction might be possible.[82] The success of these efforts is not yet publicly-known.

---

[79] https://www.sanantonio.gov/Portals/0/Files/Sustainability/STEP/CPS-FY2020.pdf, p. 11, Table 1-1.

[80] https://austinenergy.com/wcm/connect/5f6f5cdc-31bb-436c-a52f-a050d113b5d2/DemandResourceMWSavings-WP.pdf?MOD=AJPERES&CVID=mRLC6hb, pp. 15-17.

[81] For example: https://www.reliant.com/en/residential/electricity/save-energy/degrees-of-difference-rewards.jsp; https://www.txu.com/savings-solutions/txu-ithermostat.aspx

[82] See, for example: https://newsroom.cpsenergy.com/update-as-of-sunday-february-14-2021-400-pm-winter-weather-and-extreme-cold-puts-community-at-risk-state-grid-operator-and-cps-energy-call-for-customers-to-reduce-electric-and-natural-gas-use/.

2.5.7. Aggregate Levels of Demand Response

It is clear that a very large demand reduction was achieved during the February event through a combination of formal programs and involuntary load shed action, by the grid operator, TDSPs, load-serving entities, and individual consumers. ERCOT has estimated that over 32,000 MW of demand reduction was achieved through the sum of these actions when demand reduction peaked in the morning of February 16, while the previous day saw peak levels of demand reduction of over 28,000 MW.[83] However, it is not possible to specifically attribute the demand reduction to each of these specific actions. Involuntary load accounted for the majority of load shed, and these load shed actions by a TDSP limit the ability of a customer to respond to prices or take some other action, for example.

2.6. Natural Gas and Operations during February 2021

This section covers how the production and flow of natural gas changed during the event. It also provides context for the various end uses of natural gas among which total consumption is partitioned. For a primer on the balance of natural gas in Texas, see Appendix D.

2.6.1. Natural Gas Production

Per a February 25, 2021 report by the Energy Information Administration (EIA),[84] Texas natural gas production fell by almost half during Winter Storm Uri – from 21.3 billion cubic feet per day (Bcfd) during the week ending February 13, to about 11.8 Bcfd at its lowest point on February 17 (see Figure 2.q.). As a daily average over month, Texas dry natural gas production dropped from 21 in January 2021 to 13 Bcfd in February 2021.[85]

---

[83] See slide 4 at: http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx.

[84] Texas natural gas production fell by almost half during recent cold snap - Today in Energy - U.S. Energy Information Administration (EIA)

[85] https://www.eia.gov/todayinenergy/detail.php?id=46896.

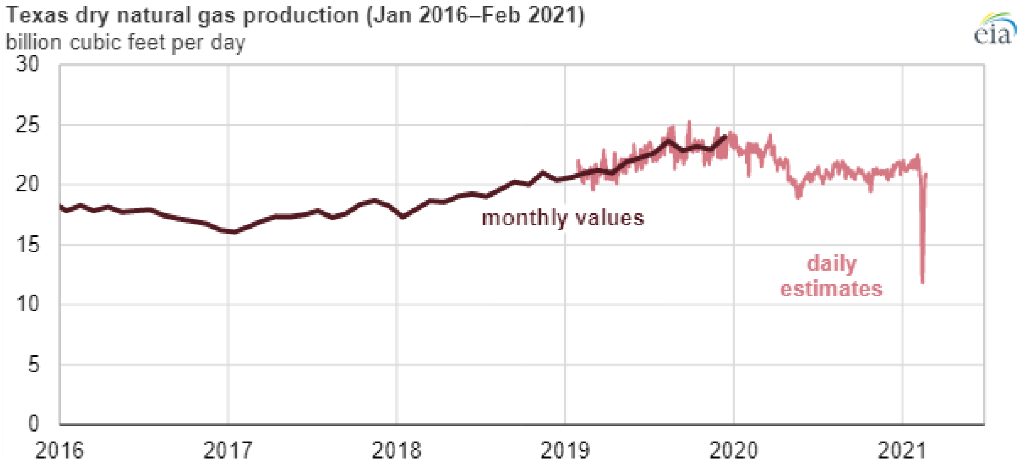


Figure 2.q. Texas Dry Gas Production through Jan 2016 – Feb 2021 (Source: EIA)

Based on a sample set of processing plants, located in the Permian, we also saw reduced residual gas[86] output from these plants during the week of the storm. Our sample includes 27 processing plants, with a total capacity 4.4 Bcfd, which is about 25% of the total 17 Bcfd capacity in the Permian Basin.

Two key observations arise from an examination of this sample set of processing plants:

- Per Figure 2.r, out of 27 gas processing plants in our sample, eight had zero output on February 15, 15 had zero output on February 16, and 18 had zero output on February 17.
- Figure 2.s shows the reported output from these 27 processing plants in February versus their inlet capacity. In early February, throughput was around 1.6 Bcfd, but declined to 1.4 Bcfd on February 12 and 13, and then on February 14, declined rapidly over the next three days to 0.257 Bcfd on February 16. This is an approximate 85% drop from the throughput level earlier in the month.

Since the Permian Basin produces about 50% of the dry production in the State of Texas and the data in Figure 2.s represent part of the processing plants from the Permian, the loss of production out of Permian Basin could have been close to 8 Bcf on February 13, which aligns with the reported single day drop of Texas from the EIA report. For the month of February, based on sample data, the daily average Permian gas processing could have been reduced by 6 Bcfd, or about 75% out of the reported 8 Bcfd reduction for Texas overall.

[86] Residual gas is the natural gas that is left after natural gas processing, which is free from impurities, moisture, natural gas condensates and is ready to be transported to the end user market through gas pipelines. Residual gas is also known as pipeline quality dry gas.

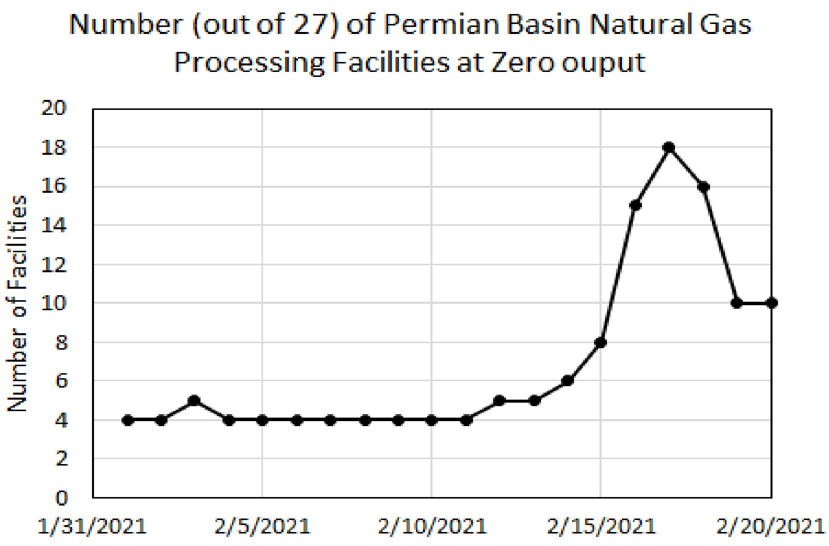


Figure 2.r. Number of Permian Basin natural gas processing facilities at zero output, out of our sample of 27 facilities. (Source: Wood Mackenzie)

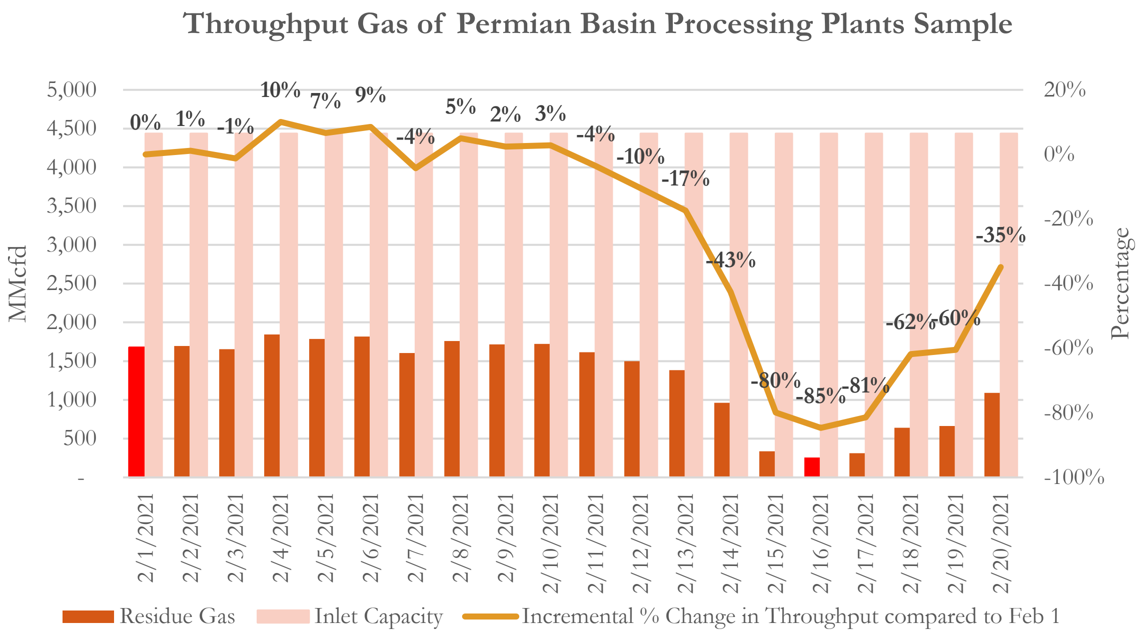


Figure 2.s. Throughput gas of Permian Basin processing plants out of our sample of 27 facilities. (Source: Wood Mackenzie)

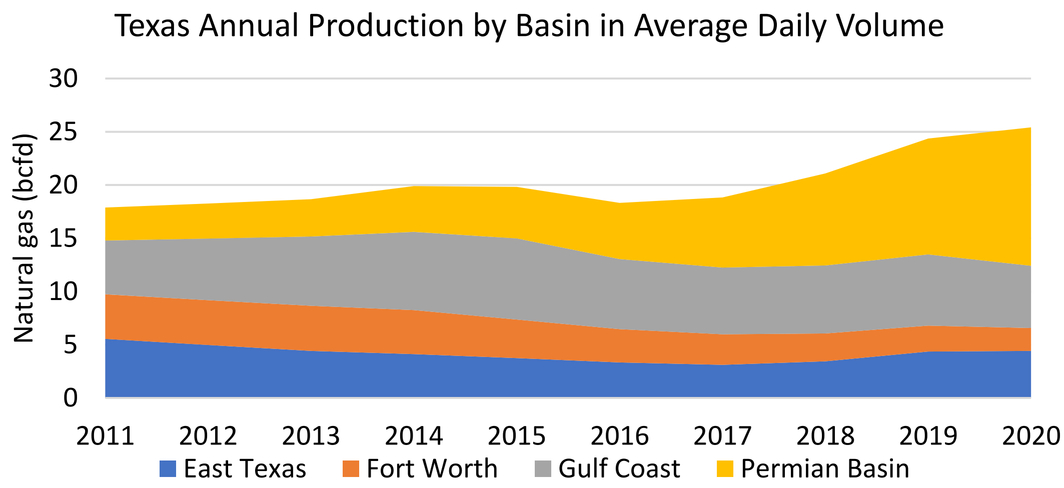


Figure 2.t. Texas natural gas production by basin since 2016 (Source: GPCM^{TM})

The sample processing plant data indicates a severe reduction in dry gas production. There are two major factors contributing to the decline of dry gas production in Texas during the storm: frozen infrastructure and electric power interruptions.

Freeze-offs at wellheads can occur when unprotected wellheads experience sufficiently low ambient temperatures causing water and other liquids in the gas to form ice that can accumulate to such a degree as fill the entire cross-sectional area of pipes and prevent flow to the wellhead. The consequences can range from a minor inconvenience to major reductions in natural gas production. Wellheads in Texas are generally not hardened for freezing conditions.

Figure 2.t shows the trend of average daily Permian Basin natural gas production since 2011. During this time a higher percentage of gas production shifted to the Permian, avoiding some weather interruptions more frequent in the Gulf Coast region, such as hurricanes, but increasing vulnerability to cold weather. Furthermore, the Permian Basin gas generally has a higher water content, making it more prone to freeze in cold weather and form hydrates which can block the flow of gas.

It is also possible, and has been noted by some natural gas companies, that power interruptions to critical infrastructure contributed to a further decline in dry gas production during the week of the storm. Remote processing plants, especially larger ones (greater than 50 million cubic feet per day throughput), typically used to have on-site power generation, but more modern processing plants are often grid connected. The data indicate that natural gas output started to decline rapidly before the electricity forced outages (load shed) began early on February 15, with production declining about 700 million cubic feet per day (MMcfd) from February 8-14, (see Figure 2.s). This decline is likely due to weather-related factors and not a loss of power at natural gas facilities. However, some of the additional 600 MMcfd output decline from February 14-15 could be partly due to natural gas facilities residing on circuits that the TDSP selected to follow ERCOT's load shed orders.

2.6.2. Storage

According to the Texas Railroad Commission, there are 40 natural gas storage sites in Texas with a total maximum 17,536 MMcfd reported withdrawal rate.[87] Our sample data set[88] includes 5 interstate connected storage facilities and 7 intrastate connected storage facilities, covering about 25% of the state's total.

Figure 2.u shows the reported net flow rates for the observed interstate storage units and compares them to past years. The data show a significantly larger withdrawal of about 291,000 MMBtu/d[89] in February 2021, almost three times higher than that of February 2020. This high level of withdrawal leads to a historical low level of reserves for these storage units as shown in Figure 2.v. Based on the sample data, it appears that interstate gas storage inventory started to drop rapidly on February 9, with less than 10% of working gas storage remaining on February 18, and it was almost fully depleted by February 21 (see Figure 2.v and Figure 2.w).

[87] Gas Storage Statistics website of the Texas Railroad Commission (April 2021 report, accessed June 24, 2021): https://www.rrc.texas.gov/gas-services/publications-statistics/gas-storage-statistics/.

[88] Based on the sample set, there is about 55% coverage of intrastate storage, while 10% of interstate storage data. The data set is based on available data from Genscape Wood Mackenzie.

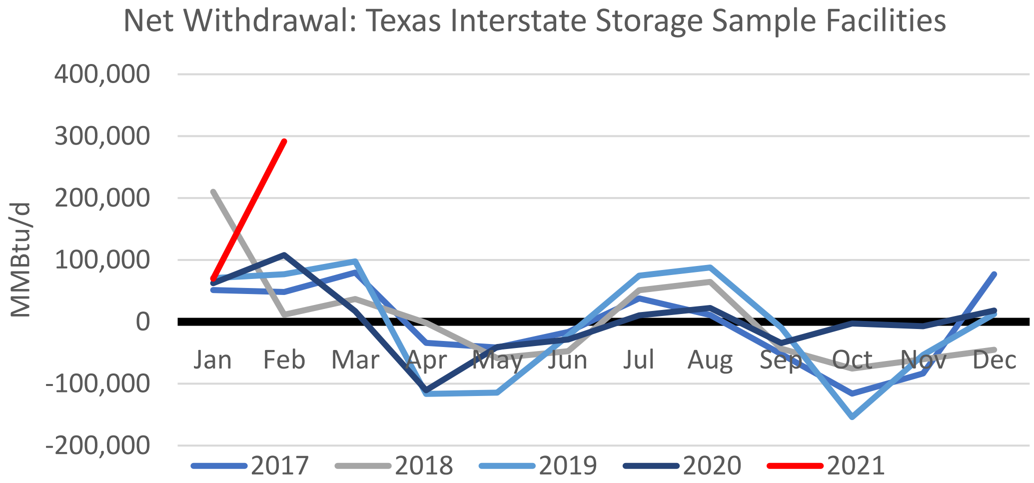


Figure 2.u. Net withdrawal rates (positive values indicate net withdrawal) as the daily average for each month for five Texas interstate storage facilities. (Source: Wood Mackenzie)

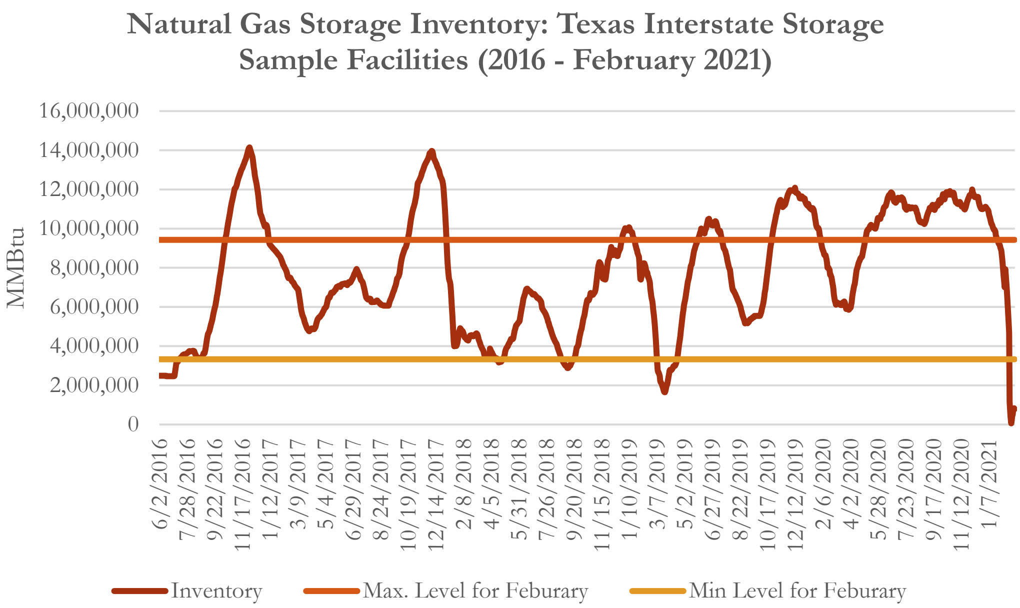


Figure 2.v. Texas natural gas storage inventory for our sample interstate storage facilities (2016 – February 2021) with lines indicating the maximum and minimum storage levels for the February months from 2016 to 2021. Note: 1 MMBtu ~ 1000 cubic feet of natural gas. (Source: Wood Mackenzie)

Figure 2.v and Figure 2.w (focusing on data for January and February 2021) show the total storage of natural gas for our sample interstate storage facilities, and Figure 2.x shows the withdrawal rates for those five facilities as a percentage of their historically-observed maximum withdrawal rates. Out of the five interstate storage units observed here, four experienced some level of increase of withdrawal during the winter event to reflect the higher demand for natural gas in the market. One of the four units, Unocal Keystone storage, experienced a large withdrawal the week of February 8. This could be a reflection of the early rise of the natural gas price which went above $4/MMBtu the week leading to the storm, which was already higher than usual.

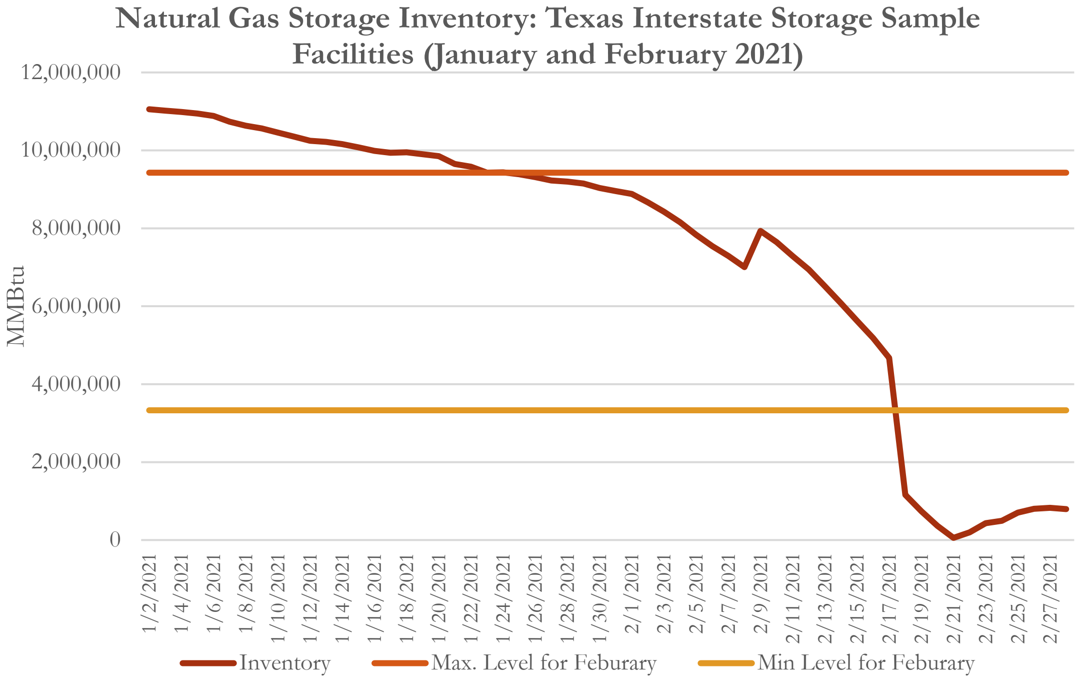


Figure 2.w. Texas natural gas storage inventory of for our sample interstate Storage facilities (January and February 2021). Note: 1 MMBtu ~ 1000 cubic feet of natural gas. (Source: Wood Mackenzie)

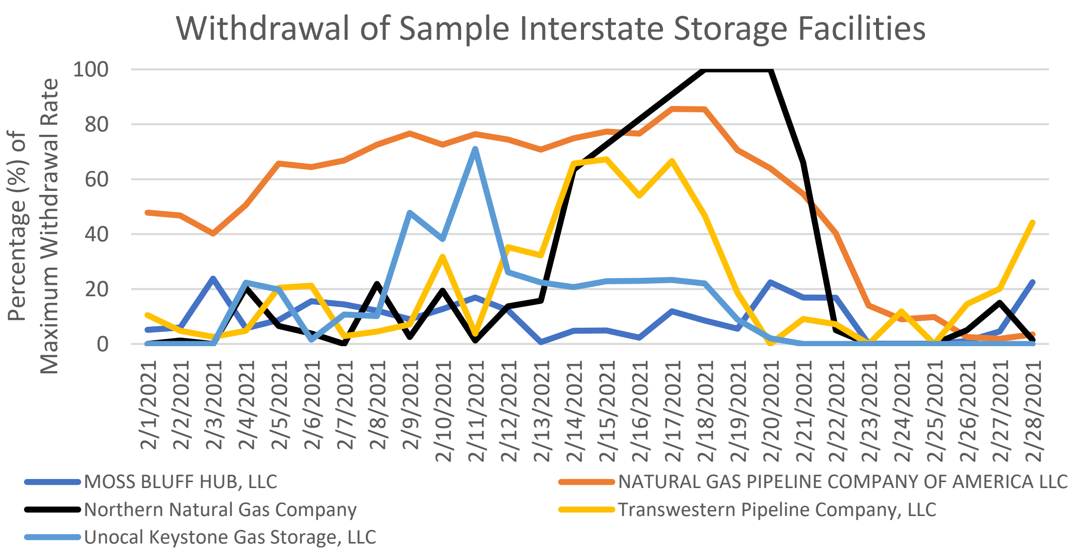


Figure 2.x. Natural gas withdrawal (as the percentage of maximum withdrawal rates) in February 2021 from each of our five sample interstate storage facilities. (Source: Wood Mackenzie)

Intrastate natural gas storage facilities also experienced high withdrawal rates through the week of the winter storm. However, the data for our sample of intrastate storage facilities indicate that during the week of February 13 their collective withdrawal rates never reached 100% of historically-observed maximum withdrawal rate capacities (Figure 2.y). These intrastate storage facilities also had higher than usual withdrawals before the beginning of the winter storm, on February 10, even at gas prices of $4 per million Btu (MMBtu). This drawdown of storage before February 14 contributed to the lack of natural gas supply going into the coldest parts of the storm and to the historically high natural gas prices during the storm that in some cases were 100 times higher than normal. *This situation leading into Winter Storm Uri was an extreme condition in which there was not sufficient gas delivery capability to prevent the extreme high price increase.*

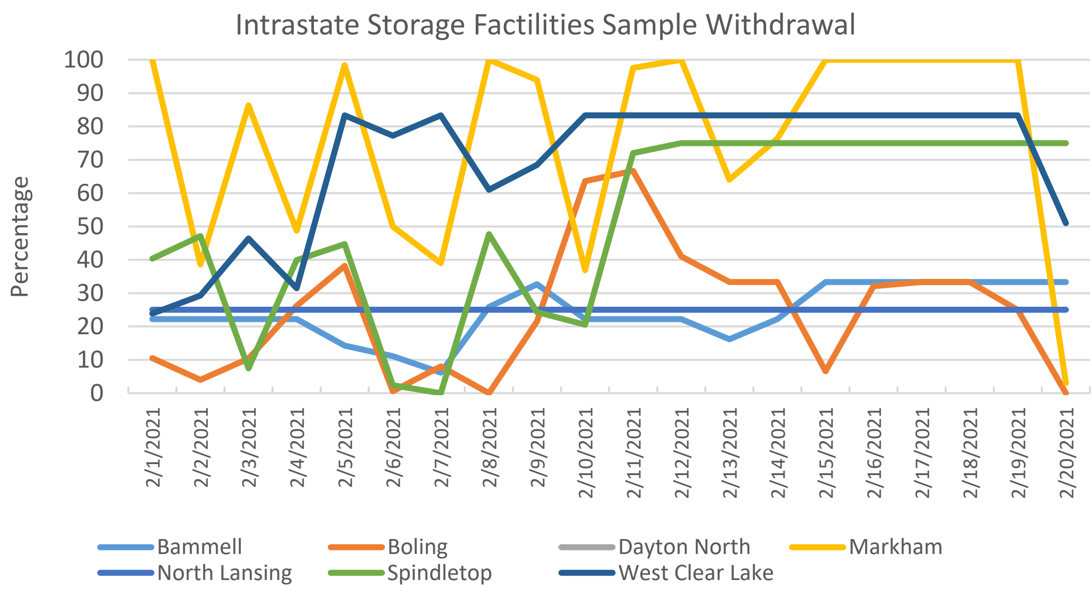


Figure 2.y. Natural gas withdrawal (as the percentage of maximum withdrawal rates) in February 2021 from each of our sample of intrastate storage facilities. (Source: Wood Mackenzie)

2.6.3. Natural Gas Demand

This section discusses the impacts on natural gas demand from the winter storm of February 2021. The dataset includes all sectors of demand in three categories, as labelled at interconnection point of the interstate pipeline network (delivery points). The dataset represents around 15% of the total consumption in Texas.

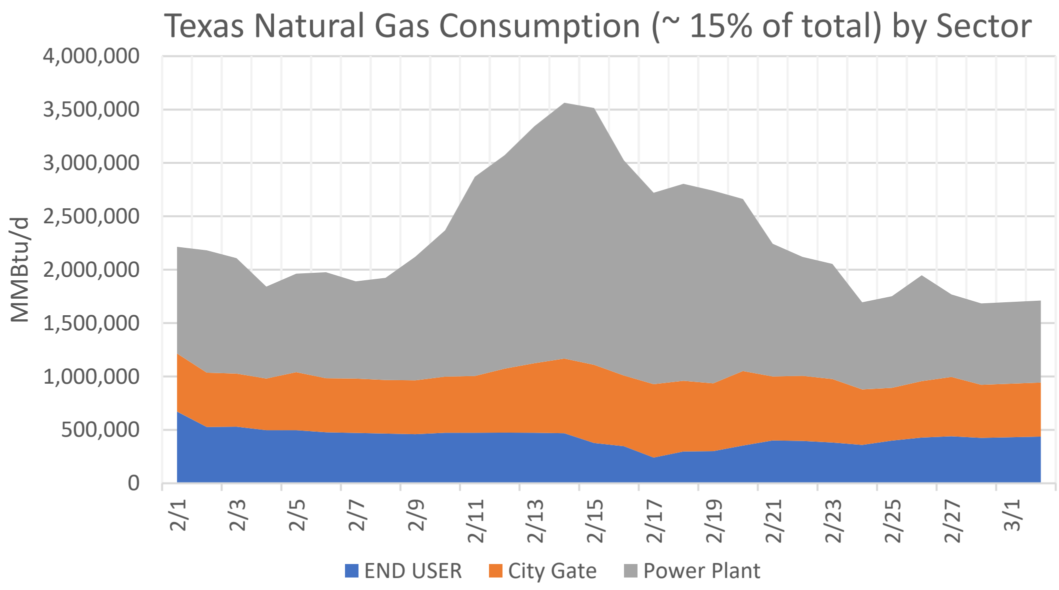


Figure 2.z. Texas daily natural gas consumption by sector (from our sample of interstate pipeline data) (Source: Wood Mackenzie)

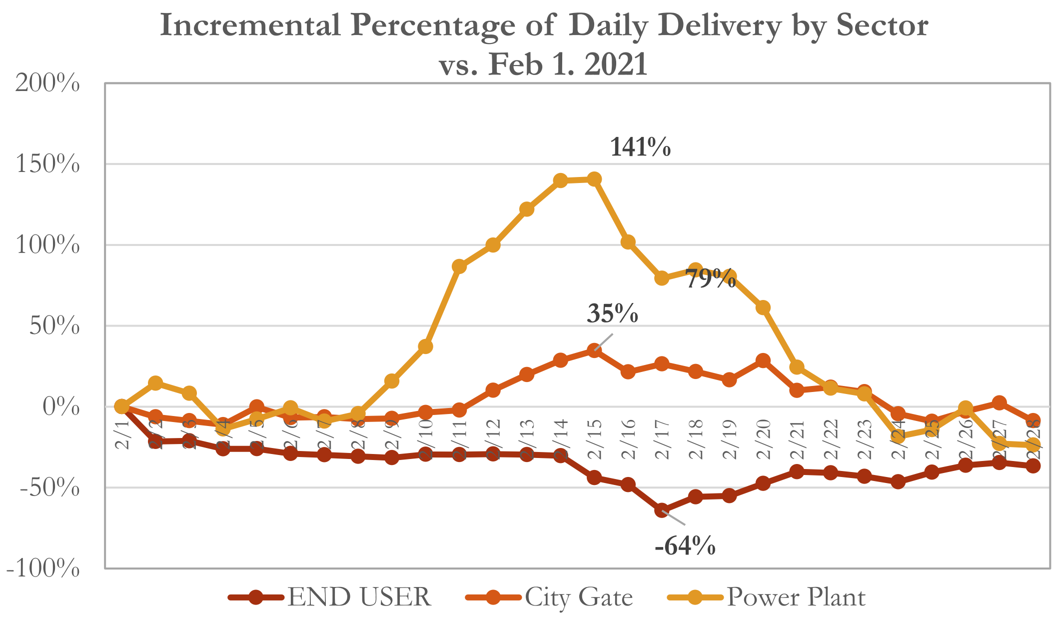


Figure 2.aa. Incremental change (in percentage) of daily natural gas delivery by sector relative to delivery on February 1, 2021, (Source: Wood Mackenzie)

Figure 2.z and Figure 2.aa show natural gas daily consumption in the sample Texas dataset by three sectors in February 2021,[90] representing overall changes and dynamics aggregated across three sectors. Figure 2.z indicates an aggregate increase in consumption peaking on February 14. Power plants and "city gate" (residential,

[90] "City gate" includes residential, commercial and some small industrial users. "Power Plants" represent connections to gas-fired power generators. Large industrial users are labeled as "End user" in the data.

commercial, and small industrial) consumers increased their natural gas consumption during the storm as industrial "end users" decreased consumption. This aligns with the Texas Railroad Commission's February 12, 2021 Emergency Order[91] that additionally prioritized natural gas to power generation just after the highest priority for residential customers and other buildings. Figure 2.aa shows the same consumption by sector as a daily percentage change versus first day of February, which provides an additional perspective on the change of consumption within each sector of gas delivery.

Figure 2.bb - Figure 2.dd show how the daily consumption of each sector in 2021 compares to past years. The consumption by large industrial users ("End Users" of Figure 2.bb) does not display a strong seasonal pattern of its demand of natural gas, but it has a higher likelihood to have interrupted demand from weather events or pandemic (see 2020 March through April). During Winter Storm Uri, the largest industrial consumers experienced the highest levels of natural gas curtailment. Relative to consumption on February 1, large industrial natural gas consumption declined by 30% on February 14 and dropped rapidly to its lowest level on February 17, to a 64% reduction. Compared to the past five years, the February 2021 curtailment in industrial sector demand is one of the biggest drops observed in the data.

City gate demand (Figure 2.cc), largely characteristic of residential and commercial demand, rose to a maximum of 730,000 MMBtu/d on February 15, which is about 35% higher than that on February 1. Natural gas consumption by power plants (Figure 2.dd) increased significantly from February 9 reaching about 140% of its February 1 level on February 14. While the natural gas system was able to significantly increase delivery during the cold weather conditions in the week ending on February 14, both city gate and power plants deliveries started to drop by February 15. As discussed elsewhere in the report, natural gas was already curtailed to some power generation facilities before February 14, and this aggregate decrease in deliveries to consumers indicates further constraints due to upstream reduction from production and storage.

[91] https://rrc.texas.gov/media/cw3ewubr/emergency-order-021221-final-signed.pdf.

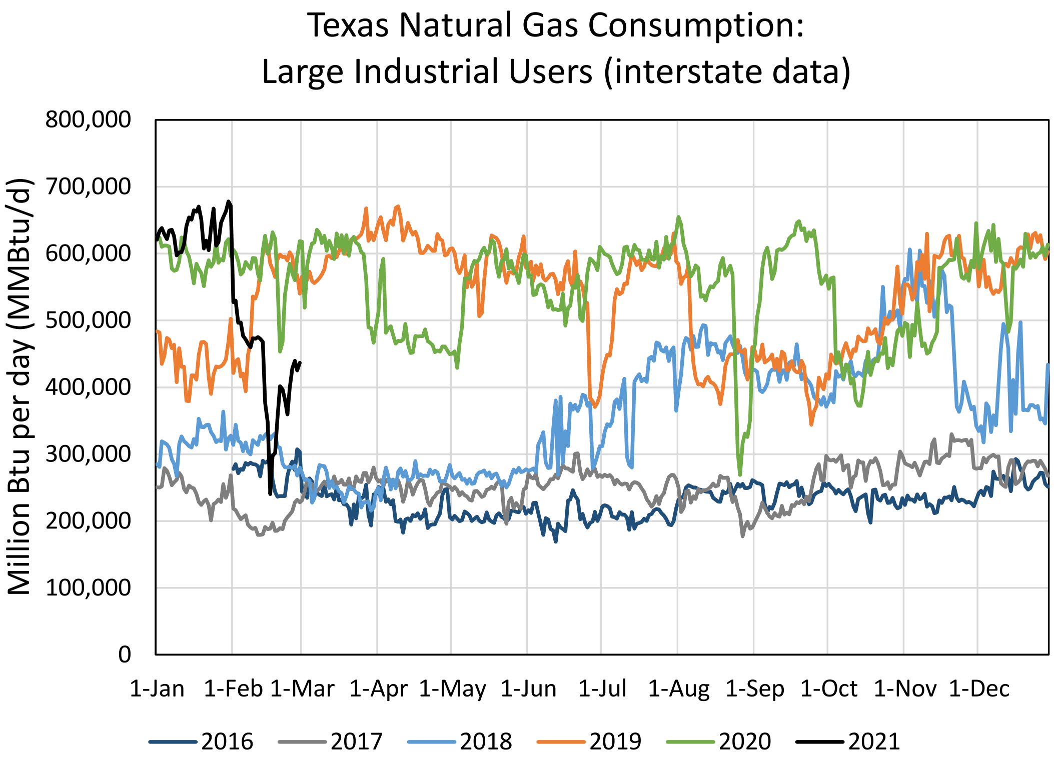


Figure 2.bb. Texas natural gas consumption for large industrial ("End User" in data set) via our sample of connection points to interstate pipelines (Source: Wood Mackenzie)

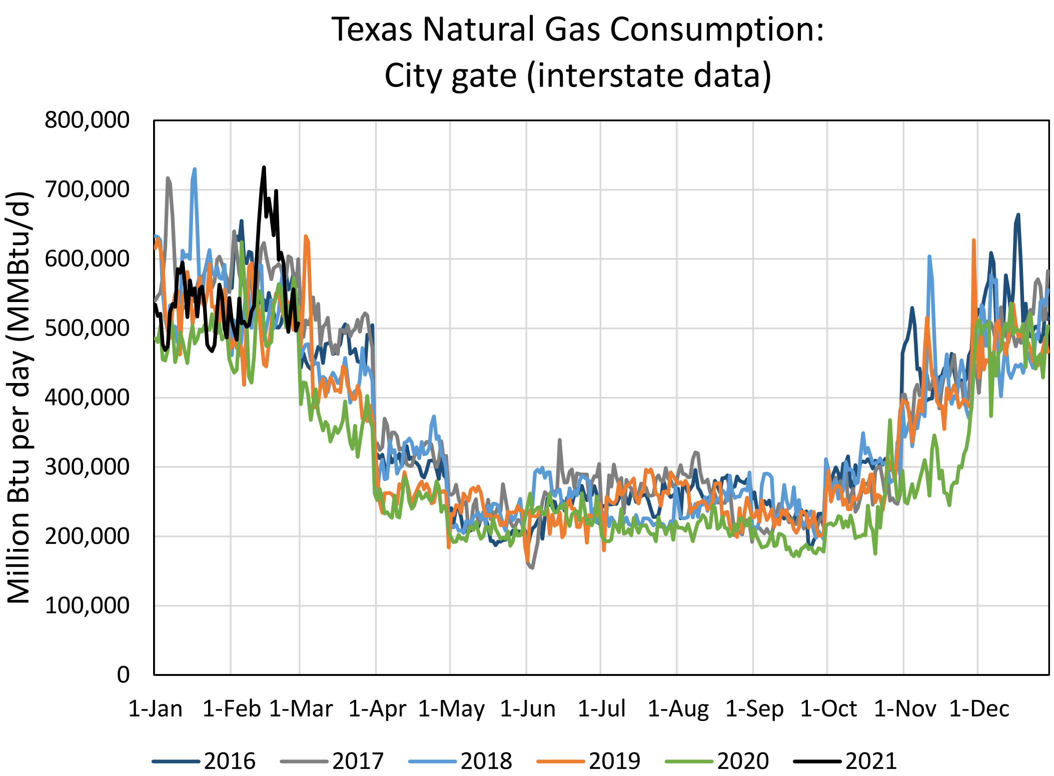


Figure 2.cc. Texas natural gas consumption for residential, commercial, and small industrial ("city gate" in data set) via our sample of connection points to interstate pipelines (Source: Wood Mackenzie)

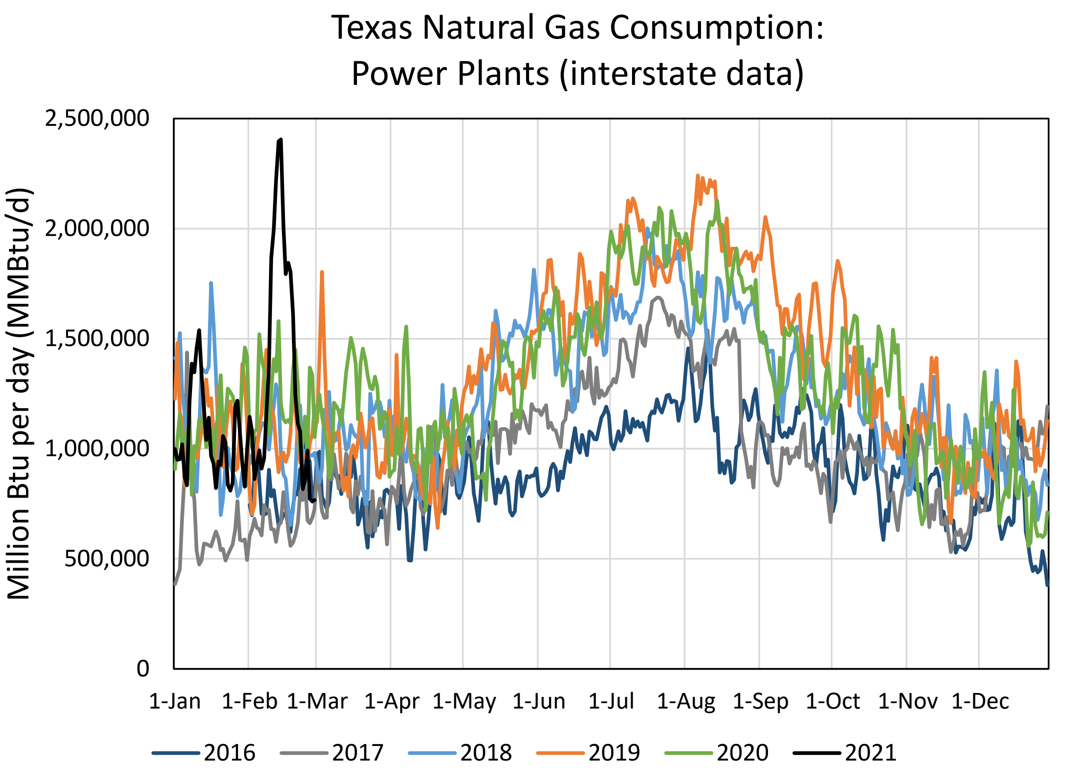


Figure 2.dd. Texas natural gas consumption by power plants via our sample of connection points to interstate pipelines. (Source: Wood Mackenzie)

2.6.4. Exports By Pipeline and Liquified Natural Gas (LNG)

Besides delivering gas to local consumers, power plants and industrial facilities, Texas exports natural gas to other states in the US and other countries including Mexico and those in Asia and Europe. To provide full context of the impacts of Winter Storm Uri on natural gas production, delivery, and consumption, we present data on the flow of natural gas out of Texas via pipeline and tanker.

Figure 2.ee shows the Texas natural gas flows by end users in Texas local markets (consumers, Electric Generation and Industrial) and exports via pipelines and liquified natural gas (LNG) ship cargos. One can observe the seasonal patterns of peaking pipeline exports and consumers demand (residential and commercial customers) in the winter with power plant consumption peaking in the summer months. In addition to the consumption within Texas and fuel losses, there has been 8-10 10 Bcfd (~10,000,000 MMBtu/d) of exports via pipelines and LNG cargos.

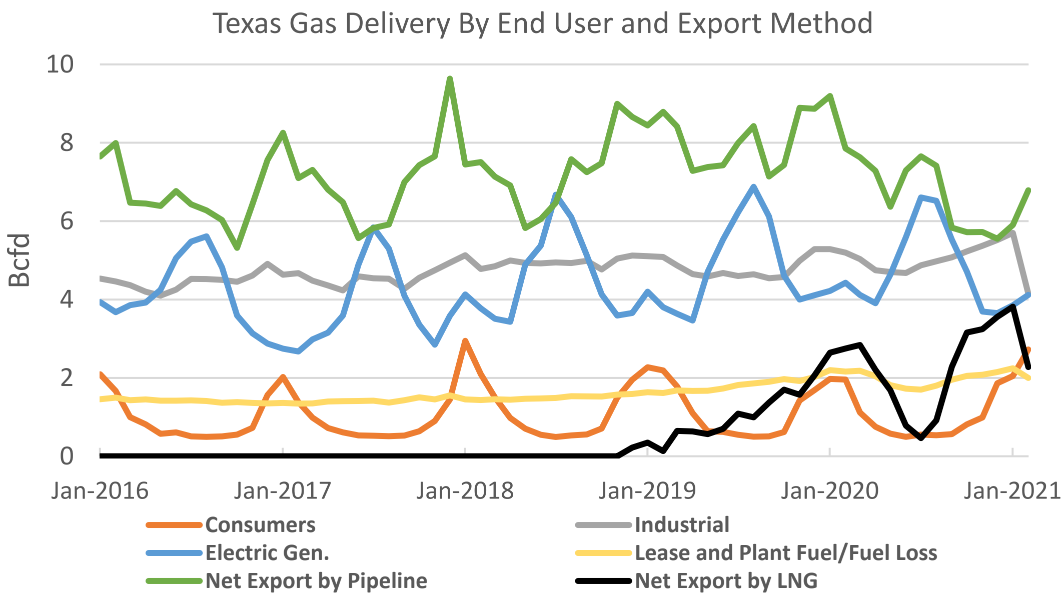


Figure 2.ee. Texas daily natural gas delivery (averaged each month) by end user (in Texas) and export method (pipeline and liquefied natural gas, or LNG, tanker). (Source: GPCMTM)

Pipeline exports from Texas reach the U.S. Northeast and East Coast markets via interstate pipelines that cross Texas' eastern state border. Pipeline exports to the midcontinent and west coast markets, including Mexico, Arizona and California, occur via pipelines that cross Texas' western border. Although many of these pipelines span a wide geographic range, it is fair to say that the exports from East and West Texas serve different downstream markets, with small exceptions.

2.6.5. Texas Pipeline Exports

Since 2016, during the month of February, Texas normally exports a net 6 Bcfd through its interstate pipelines. Figure 2.ff shows Texas pipeline net exports crossing the East and Texas West[92] border via interstate pipelines, since 2016.

Due to a lack of upstream supply, there is a reduction in both imports and exports starting in the second half of the week leading to the storm (see Figure 2.gg). During February 10-13, exports out of Texas dropped significantly below the previous five-year February minimum for the pipelines in the sample. Exports out of East Texas not only dropped to a historically low level, but also 5 out of 16 exporting pipelines reported reversed flow, declining from a net exports of average 2.8 Bcfd in February to net import of 0.3 Bcfd. For the west side, pipeline net exports dropped from 3.2

[92] There is small portion of gas exported from West Texas goes to Mexico through El Pas Gas Pipeline system. After the interconnection meter included for the Texas Export sample, there is one more meter downstream within the Texas border that measures flows to Mexico, and its flow averaged around 114,000 MMBtu/day since 2020. That exported volume can be seen in Figure 2.hh as reported data for the El Paso Natural Gas pipeline.

Bcfd in February to 0.6 Bcfd February 18, a drop of almost **95%** relative to the historical February average of 6 Bcfd.

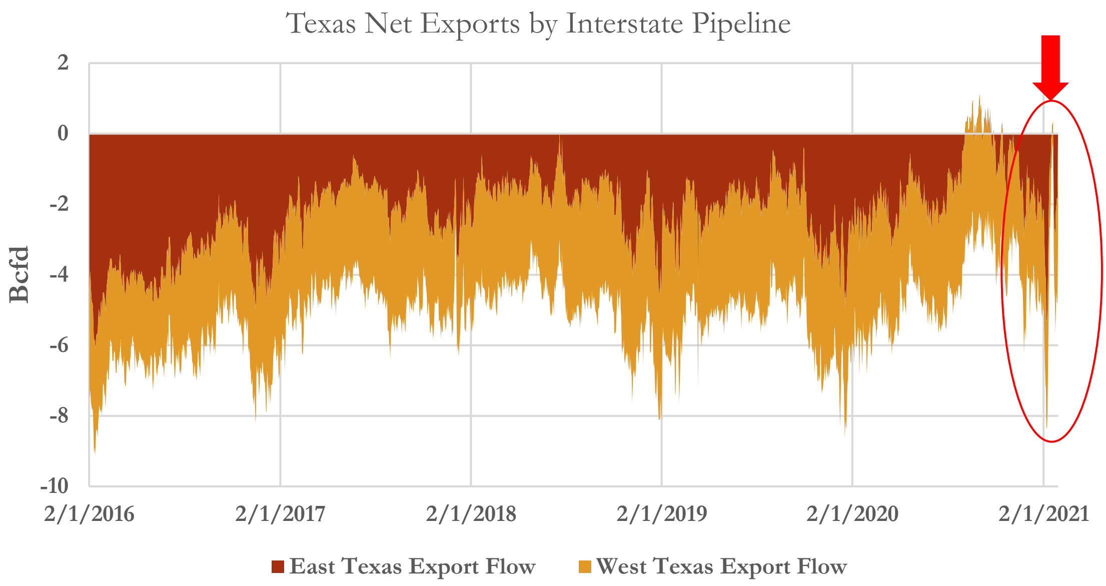


Figure 2.ff. Daily flow rates of Texas net exports of natural gas as in our sample of interstate pipelines crossing Texas' East and Western borders (2016 through February 2021). (Source: Wood Mackenzie)

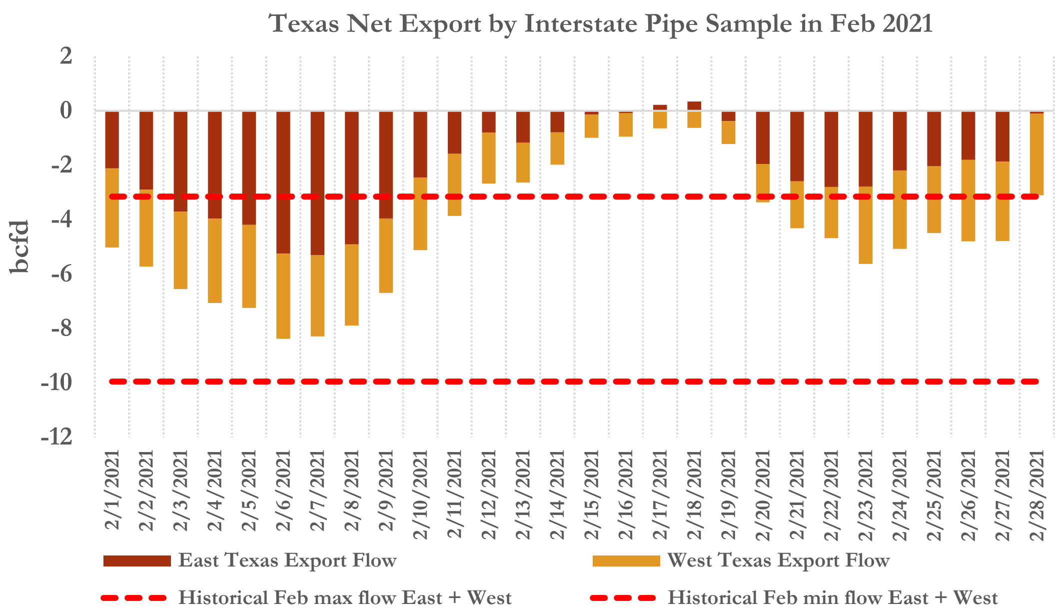


Figure 2.gg. Daily flow rates of Texas net exports of natural gas as in our sample of interstate pipelines crossing Texas' East and Western borders (February 2021). (Source: Wood Mackenzie)

Furthermore, Texas exports to Mexico have averaged around 5.3 Bcfd since January 2021, according to data from Wood Mackenzie. Figure 2.hh shows daily cross border flows, for February 2021 from Texas to Mexico, for a sample of five interstate pipelines that account for about 35% of the total Texas exports to Mexico. This figure shows that the lowest exports to Mexico occurred on February 16, during the middle of the ERCOT blackouts, at 40% below the exports on February 1.

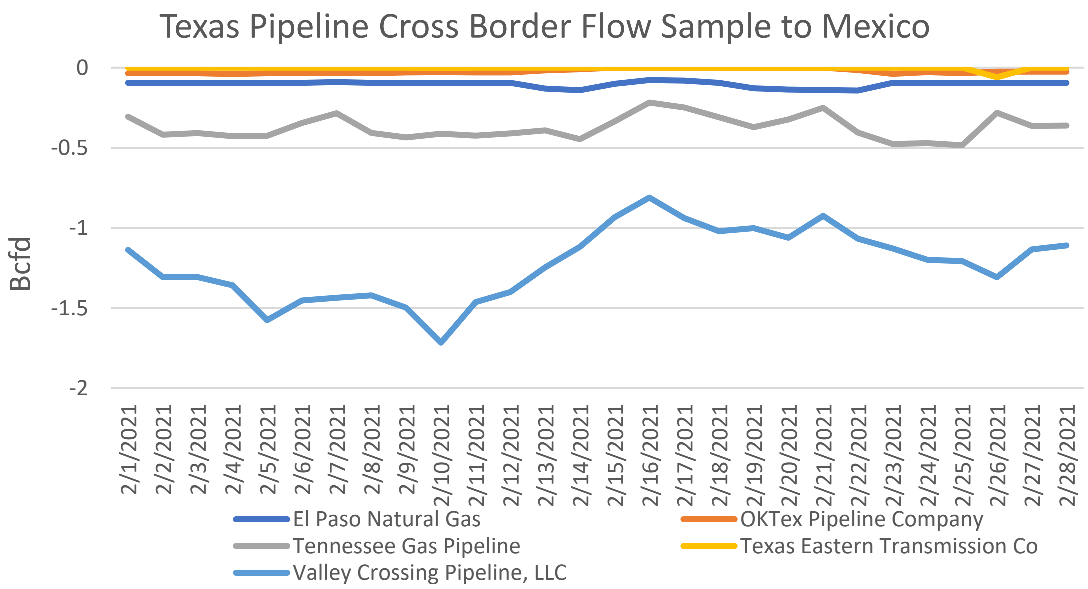


Figure 2.hh. Natural gas flow from Texas to Mexico via a sample of pipelines. (Source: Wood Mackenzie)

2.6.6. Texas LNG exports

The two main markets for U.S. liquified natural gas (LNG) exports are East Asia and Europe. For exported gas, the seasonality is determined by the demand of destination markets. There is a clear winter peaking pattern for LNG cargos with a longer winter (in Europe and Asia compared to Texas). Similar to pipeline exports, LNG exports also peak during the winter with significant heating demand in Europe and Asia. For example, in January, the month before the storm, U.S. LNG exports to China hit a new record high as East Asia was experiencing a winter that was colder than normal.

Texas exports LNG cargos from two existing LNG terminals in Corpus Christi and Freeport that have a total liquefaction capacity of 4.3 Bcfd (Figure 2.ii). Based on EIA reported data on Texas LNG exports, there was a drop in LNG exports of about 50% in February 2021 as compared to the previous month. During the winter storm, there was roughly a 25% drop of LNG cargo[93] sent out from the U.S. as a whole.

---

[93] EIA: U.S. Natural Gas Exports and Re-Exports by Point of Exit (https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENP_Mmcf_a.htm).

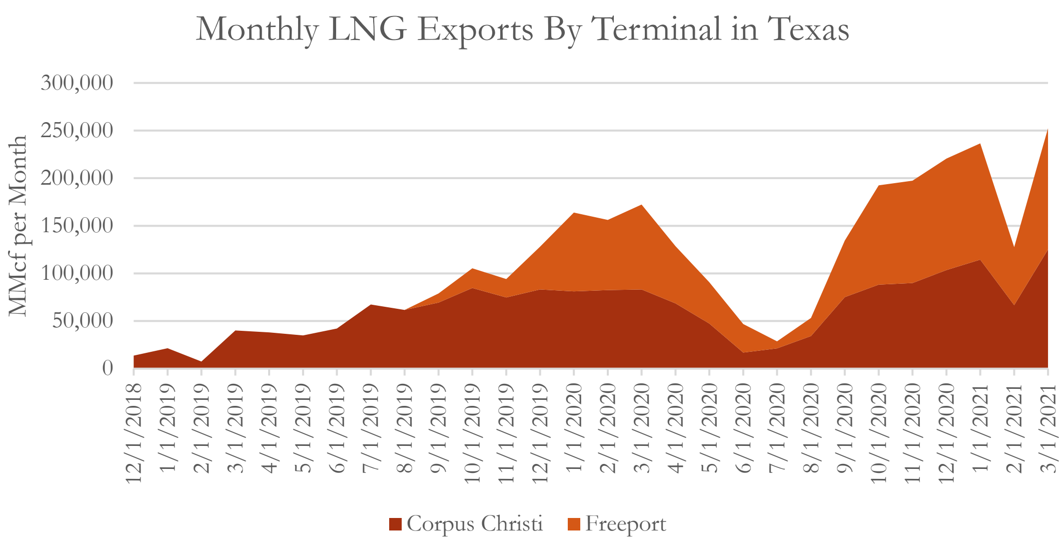


Figure 2.ii. Monthly LNG exports from Texas terminals. (Source: EIA)

2.6.7. Natural Gas Infrastructure Participation in Load Curtailment

Requests for Information (RFI) responses to ERCOT from Qualified Scheduling Entities (QSEs) indicated that approximately 67 locations (electrical meters) that were in ERCOT's ERS program were also in the fuel supply chain for generation resources, including gas refining and pipeline infrastructure. A separate set of data that compared the electric meter IDs of resources in the ERS program with those also registered as critical load with the major TDSPs indicated that 5 locations that self-identified as critical natural gas infrastructure were in the ERS program.[94]

Cross-referencing ERS participating loads in the municipal and cooperative utility regions of ERCOT identified a further 5 locations that, via satellite imagery overlaid with spatial natural gas pipeline data, appeared to also be associated with natural gas infrastructure.

It is possible that there is overlap in the RFI and TDSP datasets mentioned above, but nonetheless it does appear that some power plant fuel supply chain infrastructure, including some self-identified as critical, were participating in paid load reduction programs that would have turned them off when ERCOT deployed ERS resources.

[94] These ERS-participating locations only identified themselves as critical natural gas loads after they had been turned off by the TDSP.

3. Electricity and Natural Gas Financial Flows and Prices

This chapter recounts the economic and financial impacts of the event. Wholesale electricity prices during the event are reviewed, as well as decisions by the PUCT which affected those prices. Natural gas prices are also reviewed and the financial impacts of the price spikes in the state's electricity and natural gas industries are discussed.

3.1. Energy Prices

While the Texas electricity market structure is primarily an energy, not capacity, market,[95] it relies upon market price adjustments to help match supply and demand in real-time. These market price adjustments are the ERCOT Wholesale Electricity and Scarcity Pricing Real-time prices. They are calculated based on three categories: 1) supply and demand, 2) levels of available reserves, and 3) "out of market" reliability actions. During normal operations, prices are set by the offers of power plants, the level of demand, and any constraints[96] on the system. Over the past few years, prices during normal operations have averaged in the low tens of dollars per MWh.

When there is a risk that the supply may not be able to meet the demand, meaning there are low levels of reserves, Real-Time **Reserve** Price Adders are employed to increase electricity prices. These short-term price adders increase revenues to generators and while they are meant to incentivize investment in new generation sources, they also incentivize investment in other technologies, such as demand response. The value of the Real-Time **Reserve** Price Adders is based on the Operating Reserve Demand Curve (ORDC). Via the ORDC, once reserves fall below 2,300 MW, wholesale real time prices increase rapidly to the system-wide offer cap, currently $9,000/MWh.[97] These adders largely explain the rapid swings in real-time wholesale electricity prices, from values below $1,000/MWh to the cap, from February 12-15 (Figure 3.a).

[95] An energy-based electricity market is one in which the production of energy (i.e., megawatt-hours, MWh) is compensated, but not the availability of capacity (i.e., MW), aside from the provision of ancillary services and resources involved in emergency response programs.

[96] Such as transmission constraints.

[97] It is possible for prices to go above $9,000/MWh if additional local constraints become binding.

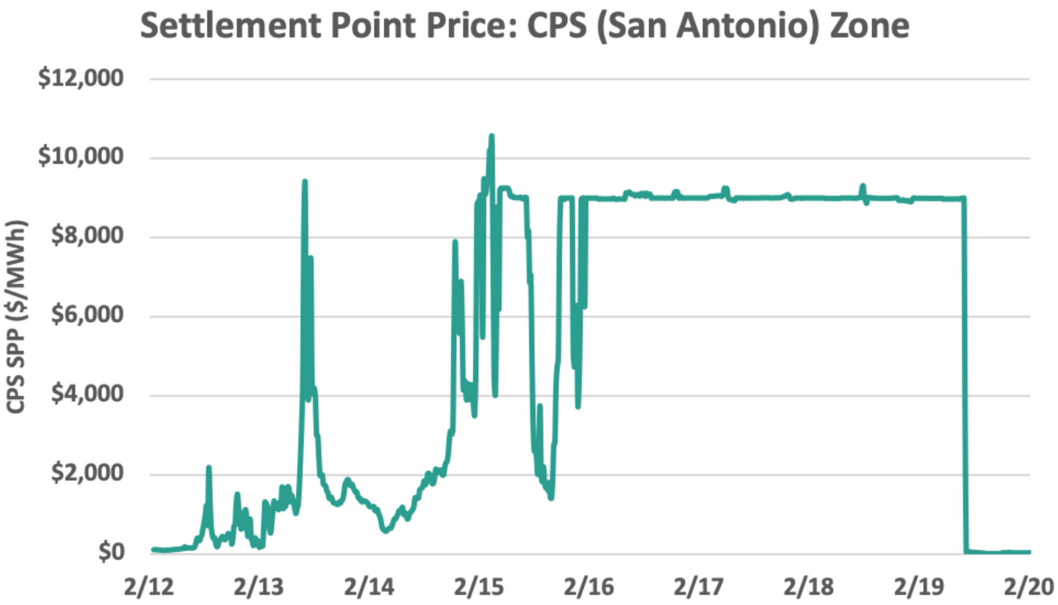


Figure 3.a. ERCOT real-time wholesale electricity prices during February 12-19, 2021 in the San Antonio Zone of ERCOT.

Real-Time **Reserve** Price Adders only include data from "in-market" conditions and do not inlcude "out-of-market" actions[98] that might impact in-market conditions. For example, if reserves drop too low and ERCOT goes into emergency operations and deploys Emergency Response Services (ERS), it may appear that reserves have increased (either via emergency generation brought online or responsive load taken offline). With a higher level of reserves, the value of the Real-Time **Reserve** Price Adders can decline even when scarcity in the market is still very high. To compensate for this possibility, another scarcity pricing mechanism, the Real-Time **On-Line Reliability Deployment** Price Adder (RTORDPA) was developed to keep real-time prices high when emergency actions have been taken.

While some forms of "out-of-market" actions are considered within the calculation of the Real-Time **On-Line Reliability Deployment** Price Adder, firm load shed is not.[99] According to current market protocols, if ERCOT initiates blackouts such that reserves appear high and recalls or cancels other out-of-market actions, price formation is once again based on supply and demand, even if demand is artificially lower due to active blackouts. This is why prices on February 15 were below $9,000/MWh for part of the day (Figure 3.a).

[98] Such as ERS deployment and firm load shed.

[99] See http://www.ercot.com/mktrules/nprotocols/current, Section 6.5.7.3.1.

3.2. Ancillary Service Prices

The prices of ancillary services (AS)[100] reached new heights during the winter event. Prior to the storm, the prices of regulation up, responsive reserve service, and non-spinning reserves had never exceeded $4,999, $8,956, and $7,000 per MW, respectively. Due to extreme scarcity, pricing protocols drove AS costs (Figure 3.b) much higher than previous levels to $24,993, $25,674, and $12,867 per MW for regulation up, responsive reserve service, and non-spinning reserves, respectively. While the PUCT did take action during the winter event to specify wholesale energy prices outside of the established ERCOT market protocols (see following section describing PUCT orders during the blackout), it did not take similar action on AS prices. The Independent Market Monitor has argued that the prices for these services should have been capped at $9,000 per MW, consistent with the energy offer cap of $9,000 per MWh.[101]

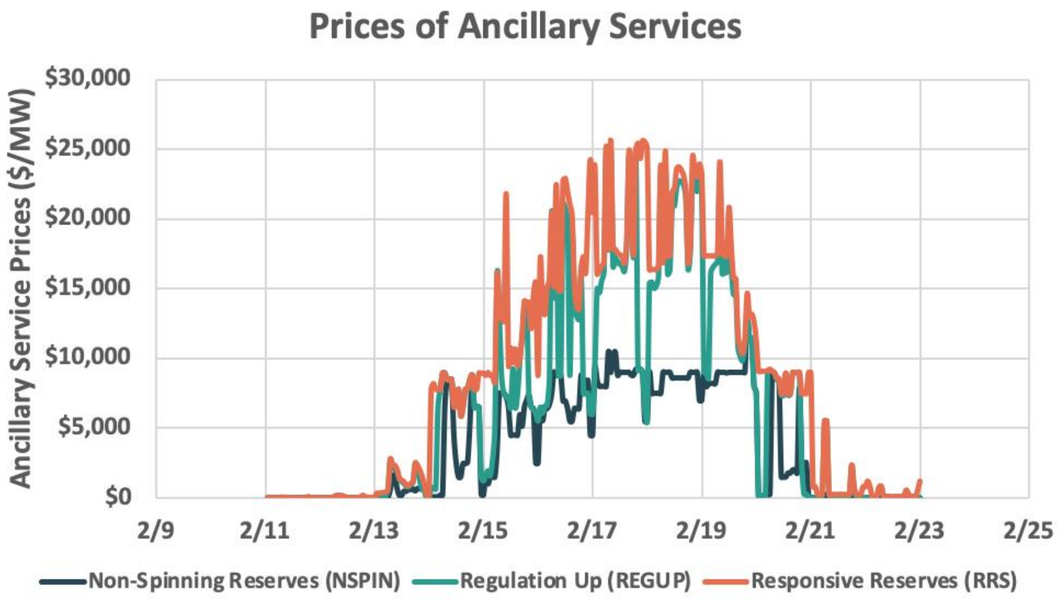


Figure 3.b. Prices of Ancillary Services from February 11, 2021 through February 22, 2021. Source: ERCOT

3.3. PUCT Orders During February Blackout

On Monday, February 15 ERCOT initiated load shed orders and found itself in an unprecedented situation with regard to solving for day-ahead market prices. It was unclear what the value of “demand” should be for the day-ahead scheduling algorithms when power had been cut off to a large percentage of customers. If

[100] The US Federal Energy Regulatory Commission’s Order 888 issued in 1996 defines AS as operating reserves (MW) “necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.”

[101] http://interchange.puc.texas.gov/Documents/51812_34_1113309.PDF.

ERCOT assumed demand levels based upon the subset of customers that were connected to the grid, then there would be enough generation to meet that demand, and prices would not reflect the level of scarcity in the market. In cases of generation scarcity, the PUCT's scarcity pricing mechanism is designed to increase wholesale prices to the applicable maximum price levels, the system-wide offer cap.[102] During the grid emergency, the PUCT attempted to impose real-time corrections to the market structure to handle this singular event.

3.3.1. Electricity Market Price Changes/Corrections During the Event

During the February freeze events, the PUCT issued two orders under Project 51617 that impacted ERCOT electricity market pricing. The first order[103] determined that prices during the load shedding that began on February 15, 2021 were not reflective of scarcity in the market, because prices were clearing below the system-wide offer cap of $9,000/MWh.[104] The Commission asserted that this outcome was inconsistent with the fundamental design of the ERCOT market. 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.[105]

The order goes on to instruct ERCOT to "ensure that firm load that is being shed in EEA3[106] is accounted for in ERCOT's scarcity pricing signals." This instruction resulted in setting ERCOT market prices to $9,000/MWh while load shedding was happening. The first order under Project 51617, issued on February 15, 2021, also retroactively raised prices in the market to the market cap of $9,000/MWh if they had been below that value between the period of time that load shed began and the order was

---

[102] The system wide offer cap can be set at two different levels, depending on the amount of peaker net margin experienced in the market so far in a given year: the High System-Wide Offer Cap (HCAP) or Low System-Wide Offer Cap (LCAP). See Texas Administrative Code Chapter 25: SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS, Section 25.505 with discussion of Scarcity Pricing Mechanism: http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf.

[103] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

[104] The system-wide offer cap in ERCOT is administratively set at $9,000/MWh, also known as the High System-Wide Offer Cap (HCAP), until peaker net margin is reached at which time protocols direct to drop to the Low System-Wide Offer Cap (LCAP) which is *the greater of* either 1) $2,000 per MWh or 2) 50 times the natural gas price index value determined by ERCOT, expressed in dollars per MWh and dollars per MW per hour. The natural gas price index value is the previous daily average price of natural gas as indexed in the Katy Hub (NPRR 952).

[105] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

[106] Energy Emergency Alert Level 3 (EEA3) is the highest level of emergency conditions at ERCOT and is the point when ERCOT is allowed to order firm load shed, i.e. instruct Transmission Operators to initiate blackouts.

issued. A secondary order[107] under the same project, issued on February 16, 2021, cancelled the retroactively raised prices section of the first order.

The second part of the February 16, 2021 order suspended the system-wide offer cap price calculation mechanism for LCAP that would have come into effect when the system reached the Peaker Net Margin (PNM).[108] The PNM value increases based on the amount of scarcity pricing seen in the ERCOT market, and it is cumulatively calculated starting from a value of $0 on January 1 of each year. The PNM threshold, defined as $315,000/MW-yr, is based on triple the Cost of New Entry (CONE) for a new peaker power plant to enter the ERCOT market. When the PNM value exceeds $315,000/MW-yr, the system-wide offer cap is supposed to change from the HCAP to the LCAP. ERCOT reports the current Peaker Net Margin levels as of 4:00 pm every day. Figure 3.c shows the PNM values throughout the storm. PNM never met its threshold before 2021, but, by the end of the week of February 15, 2021 reached a value more than double the threshold.

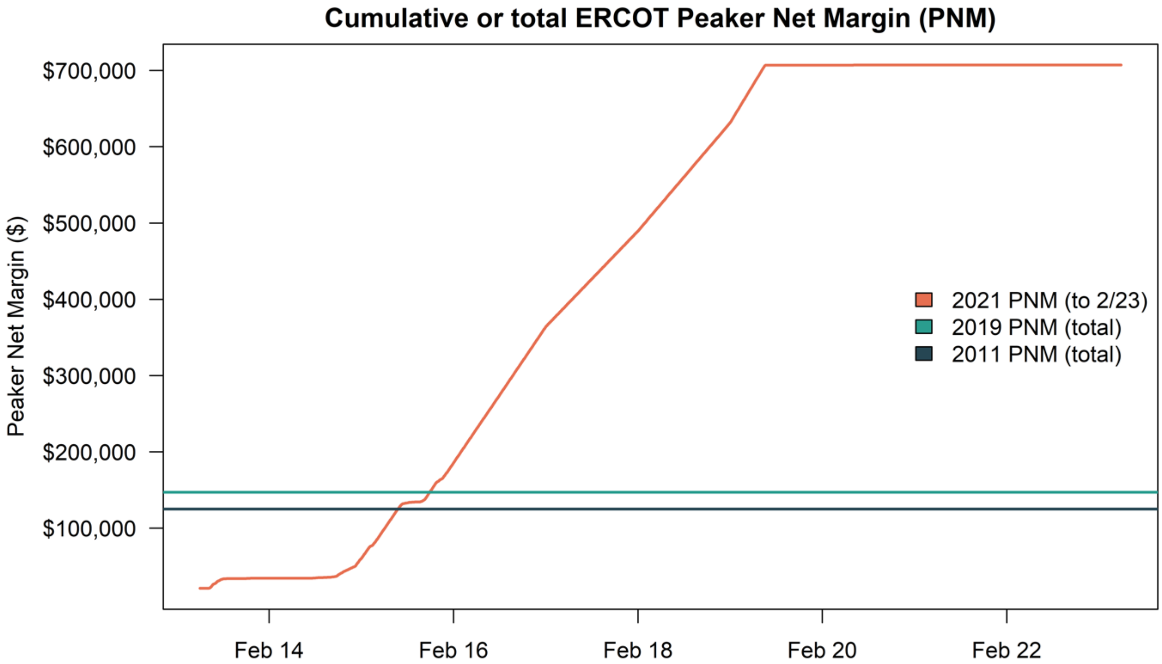


Figure 3.c. The Peaker Net Margin (PNM) for February 14-22, 2021 compared to the total value of PNM reached by the end of the years 2011 and 2019.

Once the PNM is reached in ERCOT, the wholesale price cap changes from HCAP to LCAP. When LCAP and HCAP were defined, it was assumed that LCAP would always be lower than HCAP. However, on February 16, the PUCT stated that it was

[107] https://www.puc.texas.gov/51617WinterERCOTOrder.pdf.

[108] The PNM is used to approximate the amount of profit or margin that a new natural gas-fired power plant might be able to earn, based on the cost of building a new plant, natural gas prices, and the efficiency of a new natural gas-fired power plant.

concerned that the formula for LCAP would actually translate to a higher price than the HCAP price of $9,000/MWh. The PUCT's order in Docket No. 51617 states:

> *[T]he peaker net margin (PNM) threshold [is] established in 16 TAC § 25.505(g)(6). That threshold is currently $315,000/MW-year. As provided in §25.505(g)(6)(D), once the PNM threshold is achieved, the system-wide offer cap is set at the low system-wide offer cap (LCAP), which is "the greater of" either "(i) $2,000 per MWh and $2,000 per MW per hour; or (ii) 50 times the natural gas price index value determined by ERCOT, expressed in dollars per MWh and dollars per MW per hour." Due to exceptionally high natural gas prices at this time, if the LCAP is calculated as "50 times the natural gas price index value," it may exceed the high system-wide offer cap (HCAP) of $9,000 per MWh and $9,000 per MW per hour. 16 TAC § 25.505(g)(6).*[109]

Because of the extreme demand for natural gas and constraints in natural gas supply, the price of natural gas was also much higher than normal during the February event. At one point, daily gas price averages at the LCAP-indexed hub were trading near $400/MMBTU.[110] Tom Hancock, COO of Garland Power and Light, testified that he received a quote for natural gas at $1,100/MMBtu.[111]

If the PUC had not ordered the suspension of the HCAP to LCAP transition, ERCOT would have been required to release a market notice on February 17 notifying the market that PNM had been reached on February 16 and that LCAP would have come into effect on February 18. If the LCAP had been allowed to come into effect, the LCAP calculation would have driven the market price higher than the HCAP on February 18 to $15,359/MWh. The LCAP on February 19 would have been $3,318/MWh. By February 20 the Fuel Index Price was low enough that the LCAP dropped down to $2,000/MWh.[112]

Table 3.a shows what the values for LCAP would have been if the PUCT had not suspended it.[113]

---

[109] http://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

[110] MMBTU = million British Thermal Units

[111] February 25 and 26, 2021, Joint Hearing: State Affairs and Energy Resources Part 1 and Part 2, https://house.texas.gov/video-audio/committee-broadcasts/87/.

[112] The LCAP is the greater of either $2,000 per MW per hour, or 50 times the natural gas price index value determined by ERCOT, expressed in dollars per MWh and dollars per MW per hour. This calculation assumes that the PUCT would have still have forced the market price to the system wide offer cap, but would have left the LCAP in place.

[113] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

Table 3.a. Calculation of what LCAP would have been if not for the PUCT orders.[114]

Date	LCAP ($/MWh)
2021-02-18	$15,359.00
2021-02-19	$3,318.00
2021-02-20	$2,000.00

Figure 3.d shows ERCOT market prices from February 14 to the end of February 19 without the LCAP (i.e., what actually happened) and if the LCAP had been allowed to come into effect as per protocols.[115]

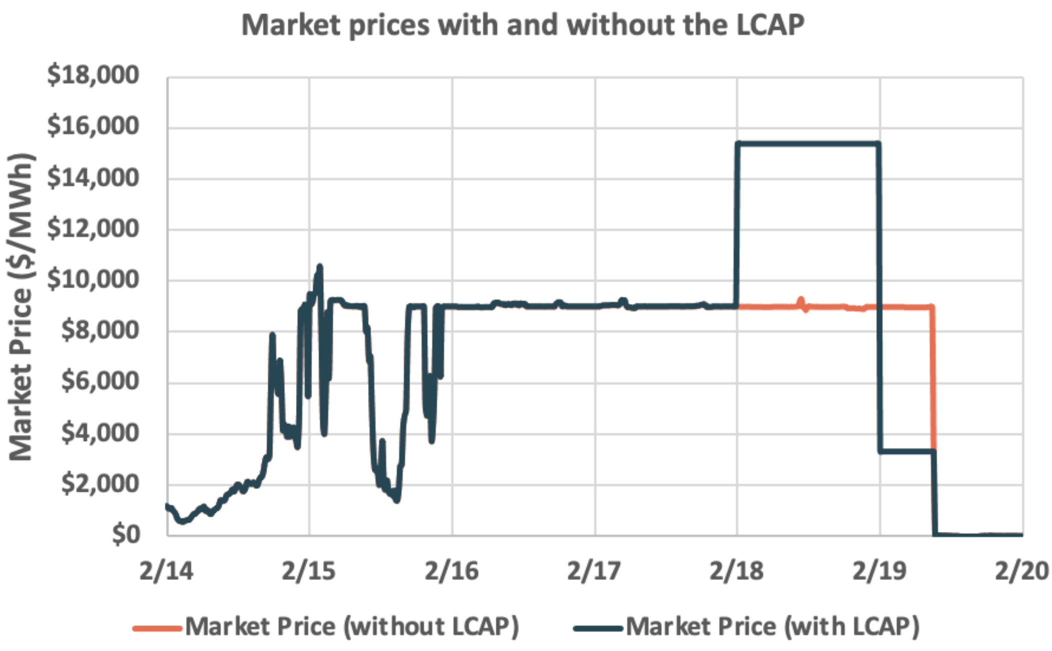


Figure 3.d. Approximate market prices with and without the LCAP (data used to calculate the LCAP provided by ERCOT).[116]

Because Peaker Net Margin was achieved on February 16, as per the ERCOT protocols, LCAP would have come into effect on February 18. On February 18, market prices would have increased from approximately $9,000/MWh (the HCAP) to $15,359/MWh. For the hours of scarcity pricing on February 19, the LCAP would have reduced prices from $9,000/MWh to $3,318/MWh. Given that the LCAP would have been approximately $6,360/MWh higher than the HCAP for the entire day on February 18, and about $5,680/MWh lower for only a short period of time on

[114] LCAP values were calculated based on the Fuel Index Price data provided by ERCOT.

[115] We make the assumption that scarcity pricing would have ended at the same time as it did in reality.

[116] These estimated prices are just the LCAP System Wide Offer Cap (SWOC) and do not include any estimate of system dynamics that, in reality, can push prices higher than the SWOC.

February 19, the overall energy costs for that week would have been approximately $5.2 billion dollars higher (Figure 3.e), or about 11% more absent action by the PUCT.

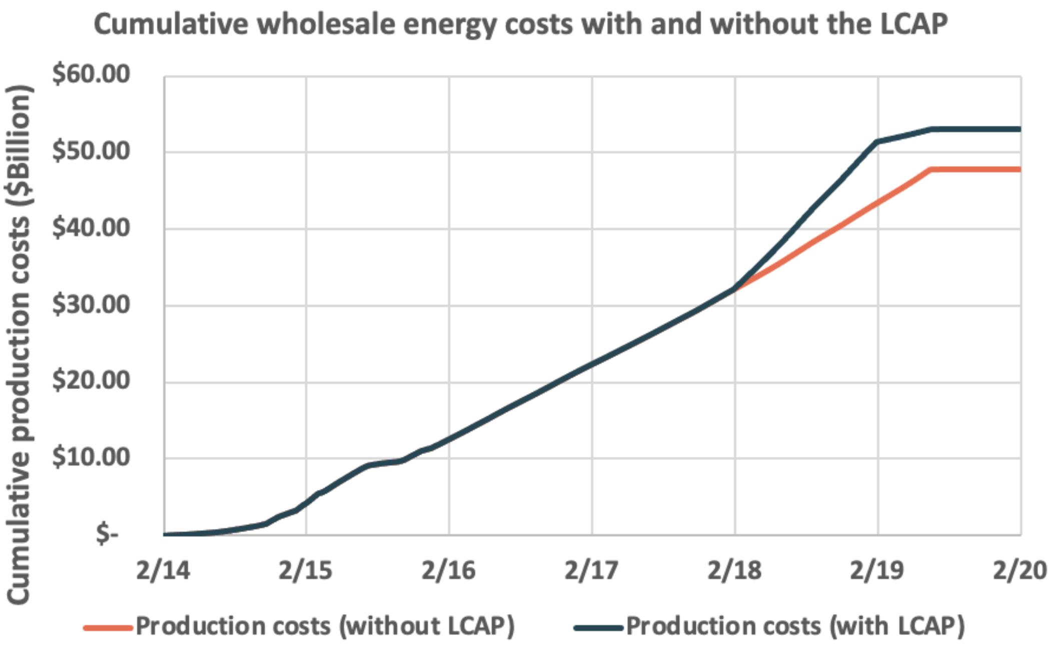


Figure 3.e. Cumulative wholesale energy costs with and without the LCAP.

Figure 3.e shows the difference in cumulative market energy costs with and without the LCAP.[117] Because the LCAP would not have come into effect until February 18, energy costs are the same for both sets of market prices until then.

3.4. Financial Fallout

Regulators and policy makers have very limited information about contracts and hedging relationships among participants in the State's electricity and natural gas industries. This is particularly true for financial transactions negotiated outside of ERCOT's formal day-ahead and real-time markets for energy and ancillary services. Such information is generally regarded as confidential. Thus, when faced with the decisions regarding whether to raise prices to attract more supply and encourage price-sensitive loads to reduce demand, or whether to "re-price" energy transacted through ERCOT's markets, the PUCT Commissioners stated that they were unable to determine which market participants might benefit or be disadvantaged by such actions.[118]

---

[117] These values are calculated by multiplying the load times the price with and without the LCAP as shown in Figure 3.d. While much energy in ERCOT is transacted in the Day-Ahead Market (DAM), it is not known how different relative DAM prices would have been had LCAP not been suspended. Thus, while the absolute numbers might be different, the percentage increase might be similar.

[118] See PUCT Open Meeting of March 5, 2021, item 22: http://www.adminmonitor.com/tx/puct/open_meeting/20210305/.

On April 14, 2021, ERCOT reported cumulative aggregate "short payments" of approximately $2.9 billion, and that it would take 96 years to collect the amount outstanding using its standard Default Uplift Invoice process.[119] This estimate was raised to $2.99 billion on May 14, 2021.[120] Of that, $1.86 billion relates to the default of Brazos Electric Power Cooperative Inc., which filed for bankruptcy on March 1, 2021. Other market participants that had failed to pay amounts owed to ERCOT at that time included Rayburn Country Electric Cooperative, Eagles View Partners LTD, Energy Monger LLC, Entrust Energy Inc., GBPower, Griddy Energy LLC, Gridplus Texas Inc., Hanwha Energy USA Holdings Corp., Iluminar Energy LLC, MQE LLC, Power of Texas Holdings Inc., and Volt Electricity Provider LP. As a consequence of receiving less revenue than ERCOT has invoiced to the market, ERCOT has reduced payments to market participants that are owed revenues from the market for congestion revenue rights.[121]

Under present market rules, unpaid amounts are uplifted to all market participants based on each market participant's MWh activity (energy bought or sold through ERCOT's formal markets) in the month prior to the defaulted payment.[122] However, these uplift mechanisms are limited to $2.5 million per 30 days.

The financial impacts on electricity retailers depend upon the degree to which their price risk was hedged and how service outages affected their obligations to provide energy during the event. Griddy Energy LLC, Entrust Energy Inc., and Power of Texas Holdings Inc. have each filed for bankruptcy.[123,124,125] Their certificates to serve customers in the ERCOT market were revoked, and their customers were moved to other retailers through ERCOT's "mass transition event" process. The customer bases of GridPlus MQE LLC (My Quest Energy), GB Power, Volt Electricity Provider LP, Energy Monger, and Iluminar Energy were acquired by JP Energy Resources, while the customer bases of Entrust Energy Inc. and Power of Texas Holdings Inc. were acquired by Rhythm.[126] Just Energy Group – using the brand names Amigo Energy, Filter Group Inc., Hudson Energy, Interactive Energy Group, Tara Energy, and

---

[119] Electric Reliability Council of Texas, Inc.'s notice of planned implementation of default uplift invoice process. PUCT Project No. 51812: Issues related to the state of disaster for the February 2021 winter weather event.

[120] ERCOT Market Notice M-A051421-01, May 14, 2021. M-A051421-01 Estimated Cumulative Aggregate Short Pay Amount (ercot.com)

[121] http://www.ercot.com/services/comm/mkt_notices/archives/5377.

[122] http://www.ercot.com/content/wcm/lists/226521/Senate_Jurisprudence_031021_FINAL.pdf.

[123] https://www.bizjournals.com/houston/news/2021/04/01/entrust-energy-bankruptcy-behind-the-deal.html.

[124] https://www.cbsnews.com/news/griddy-energy-texas-files-bankruptcy/

[125] https://www.bankruptcyobserver.com/bankruptcy-case/POWER-OF-TEXAS-HOLDINGS.

[126] https://www.prnewswire.com/news-releases/rhythm-acquires-customers-of-entrust-energy-inc-and-power-of-texas-holding-inc-301241112.html.

terrapass – also filed for bankruptcy after sustaining an estimated $250 million loss.[127]

Media reports provide some insights into how the event impacted the financial standing of some market participants. However, we emphasize that our Committee is unable to audit, verify, and affirm any of the financial information repeated here.

NRG, the largest retailer in terms of market share in ERCOT,[128] reported a negative impact of $500 million to $700 million.[129] The second-largest retailer, Vistra, expects its financial losses due to the storm to be around $2 billion.[130] Both NRG and Vistra own and operate power plants, in addition to serving retail customers.

The impacts on municipal utility systems were mixed. The state's largest municipal electric and natural gas provider, CPS Energy reported losses on natural gas fuel purchases of between $675 and $850 million, and losses on purchased power costs in the range of $175 million to $250 million.[131] In contrast, Austin Energy may have benefited by about $54 million.[132] The Brownsville Public Utility Board has estimated a shortfall of $32.1 million.[133]

Generation owners whose fleets of generation resources operated well and were able to provide generation that met or exceeded their commitments[134] were generally not financially harmed, and could have profited if a generator was able to provide generation that met or exceeded its obligations. Many generators, however, have locked-in a price for their generation through a contract or exchange, thus limiting its profit potential. If the generation owner is dependent upon natural gas as

---

[127] Gold. R. (2021). Texas Power Market Is Short $2.1 Billion in Payments After Freeze; Electric retailers failed to make payments for power purchased when prices skyrocketed during the freeze, state grid operator says. The Wall Street Journal. Feb. 27.

[128] https://www.sciencedirect.com/science/article/abs/pii/S1040619020301408.

[129] Bank of America Global Research, NRG Energy, Uri Impacts Unpacked: More Constructive Backdrop than Thought. May 6, 2021. NRG Energy, Inc. Financial Update on Winter Storm Uri Impacts: https://finance.yahoo.com/news/nrg-energy-inc-financial-winter-100100947.html.

[130] Bank of America, VST US: Uri Impacts More Complicated Than We Thought. April 27, 2021.

[131] https://newsroom.cpsenergy.com/cps-energy-will-be-taking-decisive-action-to-protect-customers-and-the-san-antonio-community-from-price-gouging-for-illegitimate-fuel-power-costs/.

[132] https://emma.msrb.org/P21441577-P21119174-P21530470.pdf.

[133] https://www.yahoo.com/now/brownsville-public-utilities-board-tx-000816313.html?guccounter=1&guce_referrer=aHR0cHM6Ly93d3cuZ29vZ2xlLmNvbS8&guce_referrer_sig=AQAAAKwSPg3ZndRfIqbgkl2hbe9Bp-QR7-qBQeINCXN5DbGZX7ha6if6FgC-zfj-MH4C8Cm4VEnmEnbXQuLSN_vGRLS5rD4CHQS6omLbqtR2gU4g-EFOI257SWf4vyv_mw1ffecwHj5Y91c-FAtrHN9PwiZ-bVT_v-uZtmDHctJ62UOK.

[134] A commitment might result from the sale of energy through a purchased power agreement (PPA), some other out-of-market bilateral contract between a generator and a counterparty, the sale of generation through a non-ERCOT market such as the Intercontinental Exchange (ICE), or an award in ERCOT's formal day-ahead market.

a fuel and the owner had exposure to the high natural gas spot prices, the net impacts would be unclear without more detailed information.

A generation owner whose fleet of generation assets failed to perform well is likely to have experienced a negative financial impact. To meet obligations through ERCOT's formal markets, such an entity may have been required to buy replacement energy at a price as high as $9,000 per MWh (or higher). It has been reported that the state's four largest power producers – Vistra, Excelon Corp., NRG Energy Inc., and Calpine — collectively lost between $2.5 billion and $4 billion due to power plant performance problems, high natural gas prices, fuel supply constraints, and other problems.[135]

Many owners of wind generation projects that failed to perform reported deep financial losses.[136,137,138,139,140] Wind generation owners often receive revenue through financial hedges. Wholesale market prices in excess of contract prices and/or wind generation below contracted quantities may trigger a payment to a counter-party (often a financial institution). This has prompted at least one lawsuit by a wind farm against a financial institution, seeking to avoid payments.[141]

Owners of natural gas-fueled power plants with performance below expectations reported losses, including Exelon.[142]

Natural gas suppliers able to produce and transport natural gas to a market for a sale based on the spot price profited during the winter week. Natural gas producers reporting large gains due to the storm include Antero Resources Corp.,[143] Comstock

---

[135] Blunt, K, Gold, R. (2021) A Texas-Sized Problem: Overhauling the Power Market --- The February storm exposed flaws in the state's hands-off approach to electricity. But changes promise to be complex and costly as lawmakers try to balance reliability and pricing. The Wall Street Journal. April 17, 2021

[136] https://www.windpowermonthly.com/article/1707858/texas-blackouts-hit-rwe-renewables-profits.

[137] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/innergex-expects-up-to-c-60m-financial-hit-from-texas-storms-outages-62715363.

[138] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/rwe-takes-material-earnings-hit-from-texas-freeze-as-impact-on-europeans-emerges-62756391.

[139] https://www.globenewswire.com/news-release/2021/02/24/2181893/0/en/Clearway-Provides-Update-Regarding-Recent-Texas-Weather-Events.html.

[140] https://www.windpowermonthly.com/article/1715644/texas-freeze-lower-european-winds-hit-rwe-q1.

[141] https://www.kltv.com/2021/03/12/lawsuit-claims-tx-panhandle-wind-farm-not-financially-responsible-after-winter-storm-causes-frozen-turbines/.

[142] https://www.bloomberg.com/news/articles/2021-02-24/exelon-sees-profit-cut-by-up-to-710-million-from-texas-cold.

[143] https://seekingalpha.com/article/4413442-antero-resources-growth-bug-bites-again.

Resources Inc.,[144] and Macquiarie Group.[145,146] Energy Transfer expects a $2.4 billion gain,[147] and BP reportedly made over $1 billion.[148] Kinder Morgan, an owner and operator of natural gas pipelines, terminals and storage, announced a $1 billion windfall profit from gas sales during the storm.[149] Yet a gas supplier unable to produce and transport gas, or who was involved in a hedging contract might have not been so fortunate.

Natural gas local distribution companies (LDCs) generally "pass-through" the commodity price of gas to ratepayers, such that LDCs' profits do not change based on wholesale gas prices. To soften the impact on ratepayers, the pass-through of high costs due to a price spike may be achieved over some extended period of time and securitization might be used to reduce debt carrying costs to the benefit of utilities and their consumers.[150] Some LDCs, including Atmos Energy, have reported challenges in financing the purchase of gas for resale to their customers during and following the winter event in light of the high prices and extended cost recovery period.[151] Some LDCs also anticipate high billing arrearages, as retail natural gas customers face utility bills with higher prices for the natural gas commodity.[152]

Various financial institutions (e.g., banks and financial trading companies) provide financing and hedges to participants in ERCOT's markets. The impacts upon companies in this sector will vary, depending upon the performance of their clients, the financial viability of their clients, and contractual terms and conditions. There

---

[144] https://theintercept.com/2021/02/23/texas-winter-storm-gas-prices-executives/.

[145] https://www.afr.com/companies/financial-services/macquarie-jacks-up-profits-on-texas-big-freeze-20210222-p574jo.

[146] https://www.reuters.com/article/us-macquarie-group-outlook/australias-macquarie-reaps-windfall-profits-from-u-s-winter-freeze-idUSKBN2AM01O.

[147] https://www.bloomberg.com/news/articles/2021-05-06/energy-transfer-made-2-4-billion-gain-from-texas-winter-storm.

[148] https://www.houstonchronicle.com/business/energy/article/BP-likely-made-at-least-1B-during-Texas-power-16133739.php; https://www.rigzone.com/news/wire/bp_execs_coy_about_texas_freeze_impact_on_gas_trading-27-apr-2021-165272-article/.

[149] Gerson Freitas, Kinder Morgan Posts Blowout Profit on Texas Winter Storm, Bloomberg. April 22, 202; Harry Weber, Kinder Morgan gets big first-quarter lift from gas price volatility due to Texas freeze. S&P Global Platts, April 21, 2021.

[150] Bank of America Global Research (2021). GAS LDC 1Q21EPS preview: The day after the storm; measuring the Feb URI. April 19, 2021. See also, HB1520 which passed in the Texas House on April 20, 2021.

[151] https://www.reuters.com/article/us-usa-weather-texas-winners-factbox/factbox-winners-and-losers-in-energy-sector-from-texas-cold-snap-idUSKBN2AQ260.

[152] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-utilities-face-unprecedented-test-in-digesting-astronomical-storm-costs-62961274.

have been media reports suggesting windfall profits for firms in this sector,[153,154] though we have not been able to independently confirm these claims.

The near-term financial impacts on retail customers are dependent upon their agreements with retail electric providers or other load-serving entities (e.g., rural electric cooperatives and municipal utility systems). The vast majority of residential energy consumers in areas of the state opened to retail competition buy electricity under fixed-price rate plans and may see little impact on their electricity costs in the near-term. Residential customers on variable pricing plans may have received unusually high electric bills, as widely reported in the media. Over time, an increase in wholesale electricity prices tends to get partially passed-through to the prices quoted in new or renewed retail electricity offers from retailers (Hartley et al., 2019, Brown et al., 2020).

[153] Chung, J, Blunt, K. (2021). Texas Storm is a Windfall for some Wall Street Firms. The Wall Street Journal. April.

[154] Meyer, G., Noonan, L., Bank of America reaps trading windfall during Texas blackouts, Financial Times, March 5, 2021, at: https://www.ft.com/content/321c4fb2-ca11-4e15-9ef5-05598dd04012.

4. A Comparison to Winter Events in 2011 and 1989

It is instructive to compare the electricity industry's performance during the February deep freeze to the two earlier winter events which led to electrical outages in the ERCOT grid:

- December 1989
- Early February of 2011.

4.1. December 1989 Winter Event

During December 21-23, 1989, the weather was similarly cold as compared to mid-February of 2021. The low temperature in Austin was the same during both events. The low in Dallas was just 1°F colder in 2021 than in 1989. Houston reached a low temperature of 7°F during the 1989 winter event, or 6°F lower than the low temperature reached in Houston in 2021.

However, the electricity industry in Texas was far different in 1989. It was dominated by vertically-integrated electric utilities in 1989, and there was little market-wide control over operations.

Months before the 1989 winter event, the PUCT staff warned of reliability concerns associated with ERCOT's high reliance on natural gas for electricity generation, which represented 53% of the generation mix in 1989.[155]

> *Dependence on natural gas in the ERCOT generation mix (almost three times the national dependence) represents some reliability concern. … if severe winter conditions were to occur, there could be curtailment of gas supply for generating units. If such curtailment does occur and it becomes necessary to substitute fuel oil for gas, the rated capability of some units will be reduced due to equipment design, pipeline delivery constraints and/or oil inventories.*[156]

During the December 1989 winter storm, demand for electricity increased, along with the demand for natural gas for space heating. Weather-related equipment problems caused generating units to go offline. Power plant outages were traced to frozen instruments, frozen valves, boiler tube leaks, frozen batteries, and fish plugging cooling water intakes. Consistent with the concerns expressed by the PUCT staff earlier in the year, natural gas flows were curtailed by Lone Star Gas to the

---

[155] Public Utility Commission of Texas, Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988, Volume I: Summary of Results and Recommendations, Feb. 1989, p. 6.6.

[156] Public Utility Commission of Texas, Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988, Volume I: Summary of Results and Recommendations, Feb. 1989, p. 6.7.

utilities in North Texas in early hours of December 21st, and many utilities serving South Texas lost their natural gas supplies the following morning. There was firm load shed of 1,710 MW (4.5% of peak load) on December 23rd, 1989. "Rolling" blackouts were achieved, lasting less than 10 hours for any given region, and different regions of ERCOT experienced different durations of outages. System frequency remained above 59.65 Hz throughout the event. At the time, the 1990 PUCT report on the 1989 winter event stated that "The combination of heavy demand and loss of generating units caused near loss of the entire ERCOT electric grid.[157] We now know the generator outages and blackouts were far smaller in magnitude than the outages in February 2021.

The financial impacts of the December 1989 event were quite modest in contrast to later events. Natural gas prices remained fairly stable in December 1989, as did retail electricity prices. The PUCT reviewed the costs incurred by the utilities under its jurisdiction and approved recovery of those costs determined to be reasonable and necessary and prudently-incurred. The utilities reported that corrective actions would involve costs of less than $3 million (which did not include costs that might be incurred by non-utility generators).[158]

4.2. February 2011 Winter Event

During the first week of February 2011, unusually cold and windy weather prevailed over the southwest U.S. While the weather was not as severe as during the winter events in 1989 and 2021, it nonetheless triggered similar problems. The FERC 2011 summary report of the winter event noted a total of 210 individual generating units in ERCOT experienced either an outage, a derate, or a failure to start, leading to a controlled load shed of 4,000 MW, affecting 3.2 million customers (FERC, 2011).[159] The FERC 2011 summary report also noted "... 193 ERCOT generating units failed or were derated, representing a cumulative loss of 29,729 MW" that was not a simultaneous outage in capacity and a peak of 14,702 MW in "... generation offline from such trips, derates, or failures to start." Thus, approximately one-third of ERCOT's total generation fleet was unavailable at the lowest point of the event.[160] Generation loss involved units of all ages and multiple types of fuel.[161] The Texas

---

[157] Public Utility Commission of Texas, Electric Division Evaluation Report, Electric Utility Response to the Winter Freeze of December 21 to December 23, 1989, November 1990.

[158] Electric Division Evaluation Report, Electric Utility Response to the Winter Freeze, Public Utility Commission of Texas, November 1990.

[159] FERC/NERC (2011), p. 1.

[160] FERC/NERC (2011), p. 7.

[161] Trip Doggett, ERCOT CEO (2011), ERCOT Presentation to Joint Senate Committees, February 2, 2011 Grid Emergency Events. February. Slide 10.
http://www.ercot.com/content/news/presentations/2011/Senate_EEA_Presentationfinaltg.pdf

Reliability Entity (TRE) report on the same blackout noted "... a total of 225 individual generator units experienced a unit trip, a unit de-rate, or a failure to start …" resulting "... in a maximum of 14,855 Megawatts (MW) of unplanned unavailable capacity during the period. These generation issues, combined with pre-scheduled generation outages of 12,413 MW, created a significant generation capacity shortfall in the ERCOT Region." (TRE, 2011) We do not have an explanation for these variations in the number of generator outages within the FERC report and between the FERC and TRE reports, but they are within about 30 generation units. Both FERC and TRE noted very similar forced outages and derates of 14,702 MW and 14,855 MW, respectively.

On February 2, 2011, wholesale market prices reached the offer cap, which had recently been increased to $3,000 per MWh. The EEA Level 3 lasted from 5:43 a.m. to 2:01 p.m. on that day.[162] Frequency remained above 59.5 Hz throughout the event.[163]

The natural gas system could not meet demand. The production losses stemmed principally from freeze-offs, icy roads, and electric outages to the equipment used in the natural gas industry. Electric blackouts called by ERCOT and implemented by the TDSPs along with customer electrical curtailments for other reasons caused or contributed to 29% of the natural gas production outages in the Permian basin and 37% of the natural gas production outages in the Fort Worth basin.[164] These outages prevented the operation of electric pumping units and compressors on gas gathering lines.

The FERC/NERC inquiry into the 2011 events concluded that gas shortages were not a significant cause of the electric generator problems during that event, nor were rolling electrical blackouts a primary cause of the production declines at the wellhead. Nonetheless, this gas and electric interdependency was a contributing factor.[165]

In response to the 2011 event, the 2011 session of the Texas legislature passed a law requiring the PUCT to analyze the preparedness of power plants for extreme weather events as in Section 186.007 of the Texas Utilities Code.[166] The statute required that

---

[162] Kent Saathoff of ERCOT Staff (2011), TDSP Curtailment Procedures and Service Restoration Priorities Plan, slide 4. http://www.ercot.com/content/news/presentations/2011/TDU%20curtailment%20workshop%20PUC%2011-3-11.pdf.

[163] Kent Saathoff of ERCOT Staff (2011), TDU Curtailment Procedures and Service Restoration Priorities Plan, slide 5. http://www.ercot.com/content/news/presentations/2011/TDU%20curtailment%20workshop%20PUC%2011-3-11.pdf.

[164] FERC/NERC (2011), p. 9.

[165] FERC/NERC (2011), p, 11.

[166] Texas Util. Code Section 186.007.

power plants submit information to the PUCT about their readiness for extreme weather events, and that the PUCT prepare a report on "power generation weatherization preparedness." More specifically, the statute required the PUCT to "analyze and determine the ability of the electric grid to withstand extreme weather events in the upcoming year" considering anticipated weather patterns. The law also authorizes the PUCT to enact rules relating to the implementation of the weatherization report, and to require power plants to amend inadequate weatherization plans. The PUCT enacted Substantive Rule 25.53 in response to the 2011 legislation.[167] The 2011 law states that this weatherization review process must result in a report by the end of September 2012, but subsequent reports could be filed as deemed necessary. The 2011 law does not explicitly require annual weatherization reports. To date only one report, in 2012, has been filed by the PUCT under Section 186.007, and this 2012 report, written by Quanta Technologies, LLC, identified best practices for winterizing power plants and winterization shortcomings at ERCOT plants.[168] We could not verify whether ERCOT generators implemented those recommendations, or whether the PUCT followed up with generators in connection with those recommendations. ERCOT, however, has held annual "winter weatherization workshops." including a September 2020 workshop that featured winter weather forecasts for 2020-21.[169]

4.3. Comparison of the Three Events

Table 4.a summarizes key indicators for comparison of the 1989, 2011, and 2021 winter events that triggered power outages in ERCOT. Caution must be exercised, however, when drawing any conclusions based on a comparison of these three events. The generation fleet has evolved over time. We have less reliance on coal and greater reliance upon renewable energy resources today. Moreover, the electric and natural gas industries have evolved over the past 32 years. Yet, some observations can be made.

Each of the three winter storms resulted in customer outages or blackouts. During each event, weather-related problems forced outages and de-ratings at power plants and the availability of natural gas to gas-fired power plants was a notable problem.

But these were otherwise very different events. The extent and duration of the outages were far greater in 2021. We are unaware of any loss of life being linked to the electrical outages in 1989 and 2011.

---

[167] https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.53/25.53ei.aspx.

[168] Report on Extreme Weather Preparedness, Best Practices, Quanta Technologies, LLC (September 27, 2012), pp. 7-18.

[169] FN--ERCOT and Texas RE Generator Winter Weatherization Workshop by (Webex Only), URL: www.ercot.com/calendar/2020/9/3/210162.

Table 4.a Summary of key metrics summarizing the severity of the 1989, 2011, and 2021 winter storms causing significant power generation outages and derates, load shedding, and low frequency conditions in ERCOT.

Descriptor	**Dec. 1989[a]**	**Feb. 2011**	**Feb. 2021**
Peak Load Estimated w/o load shed (MW)	~ 38,000 + 1,710	59,000[#]	76,819 (estimated by ERCOT)
Maximum load shed (MW)	1,710 4.3% of peak load	~4,900 8.3% of peak load	20,000 26% of peak load
Peak forced and planned Generation Outage as nameplate Capacity (MW) (planned outage in parenthesis)	~ 13,000 (not necessarily simultaneous, unable to determine peak simultaneous outage)	~ 27,200 (12,413)	52,037 (ERCOT, 2021a)
Generation units experiencing an outage (number)	86	193 to 225[170]	~ 585
Customers (meters) without power (millions)	not quantified in 1990 PUCT report	3.2	~ 4.5 (Busby *et al.,* 2021)
Duration of EEA Level 3 condition (hours)	0-9 hours of load shed spread over two different intervals (depending on region)^	~8	~105
Lowest Grid Frequency (Hz)	59.65	59.576	59.302
Natural Gas flows were curtailed to electric utilities and/or generation units before and during blackouts	Yes (< ~1,000 MW)	Yes (1,282 MW)*	Yes (6,700 MW at peak)
Did TDSPs cut off electricity supply to natural gas infrastructure?	unknown	Yes	Yes

a: Information from PUCT (1989).

#: Figure 2 of Potomac Economics (2011).

^: The Emergency Energy Alert (EEA) system did not exist in 1989. ERCOT requested utilities enact Emergency Electric Curtailment Plans (EECP) from Dec. 22, 8:40 am -12:00/12:30 pm (for North & South Texas) and Dec. 23, 6:40 am – 12:40 pm. Utilities reported firm load shedding as occurring on December 23 for: 4 hours (Houston Power & Light), 3.6 hours (City Public Service San Antonio), 2.5 hours (Lower Colorado River Authority).

*: FERC (2011), page 191.

[170] FERC (2011) report states "But over the course of that day and the next, a total of 193 ERCOT generating units failed or were derated, representing a cumulative loss of 29,729 MW." The Texas RE report states the number of failed or derated generating units was 225.

The 1989 event preceded the introduction of competitive generation and retail markets in ERCOT. The PUCT was able to review the costs incurred by the utilities under its jurisdiction and approve recovery of winterization investments through rates of those costs determined to be reasonable and necessary and prudently-incurred. These post-freeze winterization investments were estimated in the millions of dollars in aggregate (PUCT, 1990). Natural gas prices remained stable throughout the event. There were no significant "wealth transfers" between electricity suppliers and retailers or between industries.

During the 2011 event, the market structure in ERCOT was similar to today's market structure. A nodal wholesale market structure had been introduced in December 2010 – two months prior to the event. Yet, the wholesale offer cap was a much-lower $3,000 per MWh during the 2011 event – one-third of what it is in 2021. As during the 1989 event, natural gas prices remained fairly stable, in contrast to the extreme spike in gas prices experienced in 2021. The financial impacts of the 2011 event received relatively little attention, and we are unaware of data or published estimates of financial impacts.

Ninety-six of the 585 generating units (16.4%) in ERCOT that reported outages or deratings during the winter event in February 2021 also experienced problems during the February 2011 event.[171] This includes four coal-fired generating units which were operated at reduced output levels during the 2021 emergency.[172]

Eight generating units experienced outages or de-ratings during each of the three winter emergencies of 1989, 2011, and 2021. For example, the large Limestone coal/lignite Unit 1 (presently owned by NRG Texas Power LLC) reported problems from low feedwater flow and frozen instruments in 1989, experienced problems in 2011, and was partially de-rated during the winter storm of February 2021. The other seven generating units reporting outages or deratings during all three events were relatively small natural gas-fired combustion turbines or cogeneration facilities.[173] However, this comparison of performance of plants during the three events has limited value, since many power plants in operation today and in 2011 were built after 1989.

---

[171] Sources: http://www.ercot.com/content/wcm/lists/226521/Unit_Outage_Data_20210312.xlsx and PUCT Project No. 27706, filing by ERCOT, Attachment A.

[172] Calaveras Unit JKS2, Oak Grove SES Unit1A, Oak Grove SES Unit2, and Limestone Unit LEG_G1.

[173] These are Air Liquide's Bayou Cogen station's units G2 and G4; Unit1A at Luminant's Stryker Creek plant; Unit 7 at Luminant's Mountain Creek facility; CT4 at Luminant's Morgan Creek plant; and two very small gas turbines at the TH Wharton and WA Parish plants, which are presently owned by NRG Texas Power LLC. Based on publicly-available sources: PUCT Project No. 27706, filing by ERCOT, Attachment A; PUCT (1990); and http://www.ercot.com/content/wcm/lists/226521/Unit_Outage_Data_20210312.xlsx

5. Summary

The Energy Institute at the University of Texas at Austin assembled a team of faculty and researchers to identify and review credible sources of data in an attempt to provide a factual account of what happened and what went wrong during the winter disaster. Our hope is that this analysis will provide a reasonable basis for subsequent policy decisions designed to improve the performance and resilience of the State's energy systems.

Because of time constraints, data limitations, and the intention to limit the report scope to events and data rather than recommendations, many questions have been left unanswered. For example, we did not analyze the sequences of rolling outages (e.g., on a circuit-by-circuit basis), and we do not yet have a good understanding of what it might take to deploy advanced metering systems to achieve customer outages in a more "rolling" and "surgical" manner than occurred during the 2021 event. We also did not explore whether any natural gas infrastructure facilities were committed to providing an ancillary service during the event, but were unable to perform due to a disruption in their electricity supply.

Our understanding of natural gas flows during the event is incomplete, despite having acquired and analyzed a proprietary source of natural gas data. For example, even without weather-related equipment failures, it is unknown to what level of peak flow rate and duration the Texas natural gas system can deliver natural gas demand to all customers during a winter event such as Winter Storm Uri. A full understanding of the hedging positions and out-of-market contractual agreements among ERCOT market participants will probably never be known given the confidentiality surrounding such agreements, thus limiting our understanding of the full economic consequences of the event. Robust estimations of the cost of better-winterizing the energy supply system will require further site-specific analysis.

It is our hope that subsequent studies – by The University of Texas, other universities, FERC, NERC, and other organizations – may be able to make progress in these areas.

We have intentionally avoided making policy recommendations in this report. Once policy directions are better-established, we would be pleased to contribute analysis designed to explore implementation strategies, the impacts of various policy options, and related issues.

We note that while we were completing this report, the Texas Legislature passed multiple bills in response to the February event, including Senate Bills 2 and 3. These bills focus on weatherization of infrastructure as well as the governance of the grid operator and regulator. Other bills in the 2021 session, such as House Bill 4492, focus on the financial impacts of the winter storm.

Acknowledgements

This work was funded by the Public Utility Commission of Texas (PUCT) through an interagency transfer to the University of Texas at Austin. The PUCT reviewed a pre-release draft of this report to ensure that no confidential information was disclosed, but did not otherwise influence the content or findings from this analysis.

Conflict of Interest Statements

Various participants in the state's natural gas and electricity markets fund research at The University of Texas, and some contributors to this report provide consulting assistance to companies or organizations involved in the energy industry. Disclosures of any relationships that might be perceived to introduce a conflict of interest may be found via the UT Energy Institute and at: https://energy.utexas.edu/ercot-blackout-2021.

References

Adib, Parviz and Clark, Candice (1996) "Regulatory Reform, Texas Style: The Electric and Telecommunications Industries," *Texas Business Review*, Bureau of Business Research, The University of Texas at Austin, August 1996.

J. Zarnikau, Parviz Adib (2007). "Texas: The Most Robust Restructured Electricity Market in North America," in Electricity Market Reform: An International Perspective, Ed. F. P. Sioshansi and Wolfgang Pfaffenberger, Elsevier.

American Electric Power website, Central and South West Corporation (CWS) Stock History, accessed March 16, 2021 at https://www.aep.com/investors/stock/csw.

Brown, D.B., Tsai, C.H., Woo, C.K., Zarnikau, J., Zhu, S., (2020). Residential electricity pricing in Texas's competitive retail market. *Energy Economics*. 92.D.P. Brown, J. Zarnikau, P. Adib, C.H. Tsai, C.K. Woo (2020). Rising market concentration in Texas's retail electricity market. The Electricity Journal, October.

Busby, Joshua W., Kyri Baker, Morgan D. Bazilian, Alex Q. Gilbert, Emily Grubert, Varun Rai, Joshua D. Rhodes, Sarang Shidore, Caitlin A. Smith, and Michael E. Webber. (2021) "Cascading risks: Understanding the 2021 winter blackout in Texas." *Energy Research & Social Science,* 77: 102106.

Center for Advancement of Energy Markets (2003), Retail Energy Deregulation Index 2003, 4th Edition.

Cudahy, Richard D. "The Second Battle of the Alamo: The Midnight Connection." *Natural Resources & Environment*, vol. 10, no. 1, 1995, pp. 56–87.

ERCOT (2016) "Milestones in Restructuring: The ERCOT Experience so far…", presentation to the National Conference of State Legislatures by Joel Mickey, December 6, 2016. Available March 22, 2021 at: https://www.ncsl.org/Portals/1/Documents/energy/Energy_Mickey_Joel_present.pdf.

ERCOT (2021) Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation by Bill Magness, President & Chief Executive Officer ERCOT, Texas Legislative Hearings: Senate Business and Commerce Committee, House Joint Committee on State Affairs and Energy Resources, February 25, 2021. http://www.ercot.com/news/february2021.

Hartley, P.R., Medlock, K.B., Jankovska, O. (2019). Electricity reform and retail pricing in Texas. *Energy Economics*. 80, 1-11.

Hunter, Tom (2012) "History of Electric Deregulation in ERCOT", presentation at Electric and Gas Reliability Workshop April 17, 2012, available March 22, 2021 at: http://www.puc.texas.gov/agency/topic_files/101/PUC-History_Dereg_ERCOT.pdf

Krishnamurthy V, Kwasinski A. (2013) Characterization of power system outages caused by hurricanes through localized intensity indices. In *Proceedings of the 2013 IEEE Power & Energy Society General Meeting*, 2013 Jul 21 (pp. 1-5). IEEE.

NERC (2019) History of NERC, July 2019. Available May 12, 2021: https://www.nerc.com/news/Documents/HistoryofNERC01JUL19.pdf.

Potomac Economics (2011) Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011, April 21, 2011. Available http://www.ercot.com/content/meetings/tac/keydocs/2011/0505/09._IMM_Report_Events_020211.pdf.

Public Utility Commission of Texas (1989), Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988, Volume I: Summary of Results and Recommendations, Feb.

Public Utility Commission of Texas (1990), Electric Division Evaluation Report, Electric Utility Response to the Winter Freeze, November.

Smithsonian Institution (2014) "Powering a Generation of Change" project, Emergence of Electrical Utilities in America, Abuses of Holding Companies. Smithsonian Institution, 01 July 2014. Web. 06 June 2016. http://americanhistory.si.edu/powering/, https://americanhistory.si.edu/powering/past/history1.htm & https://americanhistory.si.edu/powering/past/h1main.htm#toc14.

Swadley, A., Yucel, M. (2011). Did residential electricity rates fall after retail competition? A dynamic panel analysis. *Energy Policy* 39 (12), 7702-7711.

Synchronous Interconnection Committee (SIC) (1999). Report to the 76th Texas Legislature. Feasibility Investigation for AC Interconnection between ERCOT and SPP/SERC.

Tuttle, David P., Gülen, Gürcan, Hebner, Robert, King, Carey W., Spence, David B., Andrade, Juan, Wible, Jason A., Baldick, Ross, Duncan, Roger, "The History and Evolution of the U.S. Electricity Industry," White Paper UTEI/2016-05-2, 2016, available at https://energy.utexas.edu/policy/fce.

Watson, Kirk P; Cross, Renée; Jones, Mark P.; Buttorff, Gail; Granato, Jim; Pinto, Pablo; Sipole, Svannah L.; and Vallejo, Agustín (2021) The Winter Storm of 2021, Hobby School of Public Affairs, University of Houston. Available https://uh.edu/hobby/winter2021/storm.pdf.

Zarnikau, J., Kang, L., 2009. Did the expiration of retail price caps affect competitive electricity prices in Texas? *Energy Policy* 37 (5), 1713-1717.

Appendix A. Short History of Texas Electric Grid and ERCOT: From the Beginning to 2021

The current infrastructure, rules, regulations, and organizational roles impacting the ERCOT market are the outcome of many decisions made over multiple decades. Here, we provide a brief history of these decisions to place the ERCOT outages of service in February 2021 in historical context.

For shorthand in this report, we use the acronym "ERCOT" to possibly refer to the wholesale electricity market, the infrastructure that generates and/or delivers electricity, and ERCOT the organization. ERCOT the organization does not own the electricity infrastructure (i.e., power plants, transmission and distribution lines, battery storage) within the ERCOT grid. The grid infrastructure is owned by the generation companies who participate in the market and by transmission and distribution utilities. ERCOT the organization administers the day-to-day electricity market operations and performs transmission planning. The PUCT oversees ERCOT the organization to ensure that it and the market participants comply with the legislative intent and law.

A.1. Why Does Texas Have Its Own Grid?

Electric power development began in the late 1800s as small power plants and local wires were installed in cities across the U.S., including Texas cities. By nature, they were isolated, but eventually grew enough to establish connections among themselves.

The 1935 Federal Power Act established federal jurisdiction over interstate commerce via the Federal Power Commission (FPC), which has since become the Federal Energy Regulatory Commission (FERC). The Public Utilities Holding Company Act (PUHCA) of 1935 created individual companies – utilities – with contiguous service territories. Each utility would act as a monopoly to serve customers within its geographic territory, and in return electricity rates and profits would be subject to state-level approval. PUHCA provided the framework for all electricity service until some regions restructured, or "deregulated," beginning in the 1990s (Tuttle *et al.*, 2016).

Local city grids continued to link to each other, and by the beginning of World War II, the Texas Interconnection System was formed (Cohn, 2017). "Faced with the threat of federal regulation in the wake of the 1935 passage of the Federal Power Act, the principal utilities in Texas … elected to isolate their properties from interstate commerce" (Cudahy, 1995).

In 1965, "North America experienced its worst blackout to date as 30 million lost power in the northeastern United States and southeastern Ontario, Canada" (NERC, 2019). In response, Congress passed the Electric Power Reliability Act in 1967 that led the electricity industry to form the National Electric Reliability Council in 1968, now known as the North American Electric Reliability Corporation (NERC). NERC is a council of regional electricity coordination organizations. In the wake of these changes in federal and national level coordination, in 1970 the utilities operating exclusively within Texas set up their own reliability council named the Electric Reliability Council of Texas, or ERCOT.

The question of electrical isolation of ERCOT utilities was not considered until 1974 when an Oklahoma attorney "… filed a motion with the SEC on behalf of a group of municipal and cooperative electric distribution systems served by Oklahoma Public Service" (OPS) (Cudahy, 1995). OPS was one of four utilities owned by Central and Southwest Corporation (CSW). CSW[174] owned utilities that spanned areas of Oklahoma, Louisiana, Arkansas, and Texas (Cudahy, 1995). A four-year legal battle ensued between CSW and the existing, purely Texas-based, utilities. The dispute was whether to allow utilities to sell or generate electricity within ERCOT from/to states besides Texas and become subject to interstate commerce federal regulatory jurisdiction. CSW wanted electrical connections to transfer electricity to and from Texas, and the ERCOT-only utilities did not.

These battles affected language in the federal Public Utility Regulatory Policies Act (PURPA) of 1978, and the right of the newly formed Federal Energy Regulatory Commission (FERC) to force utilities to interconnect, for example during emergencies, without triggering FERC jurisdiction for other purposes, for example the review of wholesale electricity rates (Cudahy, 1995). Following the passage of PURPA, the utilities in dispute negotiated a settlement. "They finally settled upon a direct current [DC] interconnection [between ERCOT and SPP,[175] or other states] because, unlike an alternating current tie, the power flows over a direct-current link could be controlled. … The parties agreed to other terms as well, notably that the interconnection would not subject ERCOT to federal regulation for other purposes" (Cudahy, 1995). As a result, CSW maintained interconnection across its companies in multiple states, and the ERCOT-only utilities retained state regulation but not federal regulation.

---

[174] CSW own[ed] all the common stock of four vertically integrated operating utilities: Central Power and light Company (Central Power), headquartered in Corpus Christi in South Texas; West Texas Utilities Company (West Texas), headquartered in Abilene in West Texas; Public Service Company of Oklahoma (Oklahoma Public Service), headquartered in Tulsa, Oklahoma; and Southwestern Electric Power Company (Southwestern), serving Arkansas, Texas and Louisiana and headquartered in Shreveport, Louisiana." CSW later was merged into American Electric Power, Inc. in 2000 (AEP, 2021)

[175] Southwest Power Pool.

A.2. Wholesale Market Restructuring (Deregulation) and Adjustment Timeline

In 1995 the Texas Legislature passed Senate Bill 373 to restructure the electric generation sector in ERCOT. The bill ensured equal access to the transmission grid for power generators and established ERCOT as the Independent System Operator (ISO) in 1996, the first ISO in the U.S. although its initial functions were very limited relative to today's ISOs. Before this time, ERCOT was only the reliability coordinator that reported to NERC (ERCOT, 2016). "Additional objectives of SB 373 were to ensure an equitable interconnection process, facilitate generation capacity and transmission expansion, and provide customer protection."[176] (Adib and Clark, 1996)

In addition to further restructuring wholesale power generation, Texas SB 7 in 1999 ordered the introduction of retail competition in the service areas of the investor-owned utilities within the ERCOT power region by 2002. By 2002 the investor-owned utilities in the ERCOT power region which were previously vertically-integrated were "unbundled," or separated, into three separate entities: power generation, transmission and distribution utilities, and retail electric providers (REPs). Rural electric cooperatives and municipal utility systems were permitted to either participate in retail competition ("opt in") or decline to participate, although changes in the wholesale market would affect them regardless of their decision.[177]

Prior to restructuring, generation dispatch decisions and other operational decisions were made locally in ten control areas. However, ERCOT transitioned to operating as a single control area under the legislative framework established through SB 373 (in 1995) and SB 7 (in 1999).[178]

While markets were developed for wholesale generation and retail activities, investor-owned TDSPs remain under conventional regulatory oversight.

SB 7 also gave the PUCT authority over market oversight, including oversight of ERCOT. SB 7 sought prevent the exercise of market power, including the provision that no single generation company can control more than 20% of the total installed generation capacity.[179] Via ERCOT's bylaws (as an ISO) and authority of the PUCT, a stakeholder process provides the opportunity for stakeholders (generators, TDSPs, consumer groups, etc.) to participate in the design and operation of the electricity market.

SB 7 set a Texas renewable portfolio standard (RPS) of 2,880 MW (adding 2,000 MW to 880 MW of existing capacity) of renewables and created a renewable energy

---

[176] For SB 373, see: https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=74R&Bill=SB373.

[177] See SB 7 (https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=76R&Bill=SB7) Sec. 41.051 (cooperatives) and Sec. 40.051 (municipal utilities).

[178] http://www.ercot.com/news/releases/show/77

[179] Luminant (a subsidiary of Vistra) owns almost 20% of generation in ERCOT.

credit (REC) market to facilitate that standard. In 2005, Texas legislators increased the RPS to 5,880 MW of renewable capacity, and via SB 408 directed the PUCT to facilitate the process to design and construct new transmission to serve a set of "Competitive Renewable Energy Zones" (CREZ). As of the end of 2020, approximately 25,000 MW of wind and 4,000 MW of solar photovoltaic capacity were installed in ERCOT, thus far surpassing the RPS.[180]

Table A.1. Timeline of the Evolution of a Competitive Market in ERCOT[181]

1975	Passage of the Texas Public Utility Regulatory Act (PURA), establishing the PUCT.
1978	The federal Public Utility Regulatory Policy Act (PURPA) is enacted, facilitating and providing a pricing mechanism for utility purchases of power from cogeneration and small power production.
1983	Amendments to the Texas PURA to reflect the 1978 enactment of PURPA and introduction of the elements of integrated resource planning, such as a ten-year demand and resource forecast. The PUCT is no longer responsible for forecasts and planning for electric grid investments.
1992	The passage of the US Energy Policy Act.
1995	State Legislature passes Senate Bill 373 amending the Texas PURA to introduce wholesale competition in September 1995.
February 1996	The Commission establishes the requirement for ERCOT to become an Independent System Operator (ISO) and requires utilities to offer wholesale open-access transmission service.
Late 1990s	The PUCT approved an interconnection rule to facilitate merchant plant development.
May 1999	State Legislature passes Senate Bill 7 amending the Texas PURA to introduce retail competition on January 1, 2002 and further restructure the wholesale market.
2000-2001	The PUCT finalized its decision regarding functional unbundling plans for integrated utilities. In addition, the Commission

[180] See ERCOT "Resource Capacity Trend Charts" at http://www.ercot.com/gridinfo/resource (e.g, December 2020: http://www.ercot.com/content/wcm/lists/219848/Capacity_Changes_by_Fuel_Type_Charts_December_2020.xlsx).

[181] Some information included in this table is from Adib and Zarnikau (2007).

	finalized several important rules to enhance the transition to competition within ERCOT.
August 2000	The PUCT established Wholesale Market Oversight to monitor market activities and detect market power abuses and other market manipulation.
June 4, 2001	The PUCT finalized its decision with regard to the ERCOT Protocols that established market rules for the wholesale electricity market.
July 31, 2001	The operation of the ERCOT single control area began and a pilot retail program was introduced.
January 1, 2002	Customer choice began within ERCOT electricity market and "price to beat" was established within each incumbent investor-owned-utility service area and became effective for residential and small commercial customers with peak load lower than 1 MW.
September 2002	Retail Market Oversight was established to monitor the retail market and identify areas for improvements.
February 2003	Price spikes in wholesale market prompt re-examination of the use of balancing energy, wholesale price mitigations formulas, and credit requirements for REPs.
Late 2004	Switching rates for commercial energy consumers exceeds thresholds and the "price to beat" for commercial customers is terminated in many service areas.
September 2005	PUCT decides to transition market to a nodal structure.
2005	Texas Legislature adopts SB 408 designating the creation of Competitive Renewable Energy Zones and provides authority to PUCT to direct ERCOT to plan for transmission to connect approximately 18 GW of wind capacity.
2005	The legislature adopts SB 408 that increases the number of independent representatives on ERCOT's board and designates an independent monitor for the wholesale electricity market[182].
August 2006	The PUCT approves rules (Subst. R. §25.505) for "scarcity pricing" with new energy offer caps.

[182] SB 408 (79R Legislative session in 2005): https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=79R&Bill=SB408.

2010	On December 1, the nodal wholesale pricing system goes live approximately four years after initially planned. Along with nodal pricing comes the "day ahead market" for individual power plants to bid for next-day electricity generation on a 15-minute basis.
October 2012	PUCT approves a timeline to gradually increase the energy offer cap to $9,000 per MWh through amendments to Subst. R. §25.505.
June 2014	Operating Reserve Demand Curve (ORDC) is first implemented, to raise energy prices when physical operating reserves are low.
January 2019	The PUCT orders a shift in the ORDC to increase energy prices further when operating reserves dwindle. PUCT also decides to implement real-time co-optimization in the selection and pricing of energy and ancillary services in the wholesale market.[183]
March 2020	A further shift in the ORDC is implemented.

A.3. Why isn't ERCOT Connected to Other Grids?

Previous paragraphs summarize the history of the ERCOT grid as separate from others in North America. However, the costs and benefits of interconnecting ERCOT with neighboring reliability councils were studied in the late 1990s, per a request by the Texas Legislature.[184] The established Synchronous Interconnection Committee (SIC) failed to reach a definitive conclusion regarding whether the benefits of interconnection would likely outweigh the costs:

> *Due to the complexities of the issues and uncertainties surrounding the evolving electric marketplace, the SIC was unable to conclusively establish that AC interconnection is, or is not, desirable either as a candidate transmission investment or as an instrument of policy to promote competition in future electricity markets.*[185]

It is possible that a similar analysis today would yield differing results, as questions remain surrounding the costs and benefits of greater interconnection with neighboring markets or reliability councils.

[183] See PUCT Project No. 48540.

[184] Per SB 373 (74th legislative session in 1995).

[185] SIC, 1999, cover letter.

A.4. Today's ERCOT Wholesale Market

Today, ERCOT serves 90% of the electric load in Texas. This power region has experienced consistent load growth in recent decades due to a strong economy and increasing population, unlike some other U.S. markets which have experienced little growth. Currently, 26 million people within Texas receive electric service via the electric grid managed by ERCOT.

ERCOT administers day-ahead and real-time markets for energy, as well as a day-ahead market for ancillary services (AS). ERCOT is relatively unique in that it is an "energy-only market" and thus does not operate a capacity market or impose resource adequacy targets in order to maintain a target reserve margin.[186] Market forces are heavily relied upon to provide enough generation for resource adequacy, and market price offer caps have been raised to relatively high levels in hopes of providing sufficient compensation to the generation sector to incentivize investment to meet peak electricity demand. The price offer cap has increased almost 10-fold over a span of 13 years to $9,000/MWh. While normal market operations can push prices to scarcity levels, multiple price add-ons have been developed to increase prices when reserves are low or emergency reliability actions have been taken.

ERCOT retains only a few small direct current (DC) interconnections with neighboring markets and reliability councils, and remains a fully intrastate system with limited federal jurisdiction over its market.

A.5. Characteristics of the ERCOT Retail market

Of the approximately 11 million metered customers in ERCOT, [187] about 8 million have retail choice and can select among different retail electric providers offering different electricity pricing plans and services.

Efforts to introduce competition into the retail sector of the state's electricity market began in June 1999 with the passage of Senate Bill 7 (SB 7) by the Texas Legislature. SB 7 permitted retail competition in the service areas of the investor-owned electric utilities within ERCOT's power region on a commercial basis beginning January 1, 2002. These service areas, identified in Figure A.1., include two of the nation's ten largest metropolitan areas – Dallas/Fort Worth and Houston. New entrants were permitted to compete with retail arms of five utilities that were formerly vertically-integrated: Houston Lighting and Power Company, TXU Electric, AEP-Texas North, AEP-Texas Central, and Texas-New Mexico Power Company. Oncor became the TDSP successor to TXU Electric, while CenterPoint Energy is the TDSP successor to Houston Lighting and Power Company.

---

[186] Other "energy only" markets include electricity markets in Alberta and Australia.

[187] http://www.ercot.com/content/wcm/lists/219736/ERCOT_Fact_Sheet_1.04.21.pdf

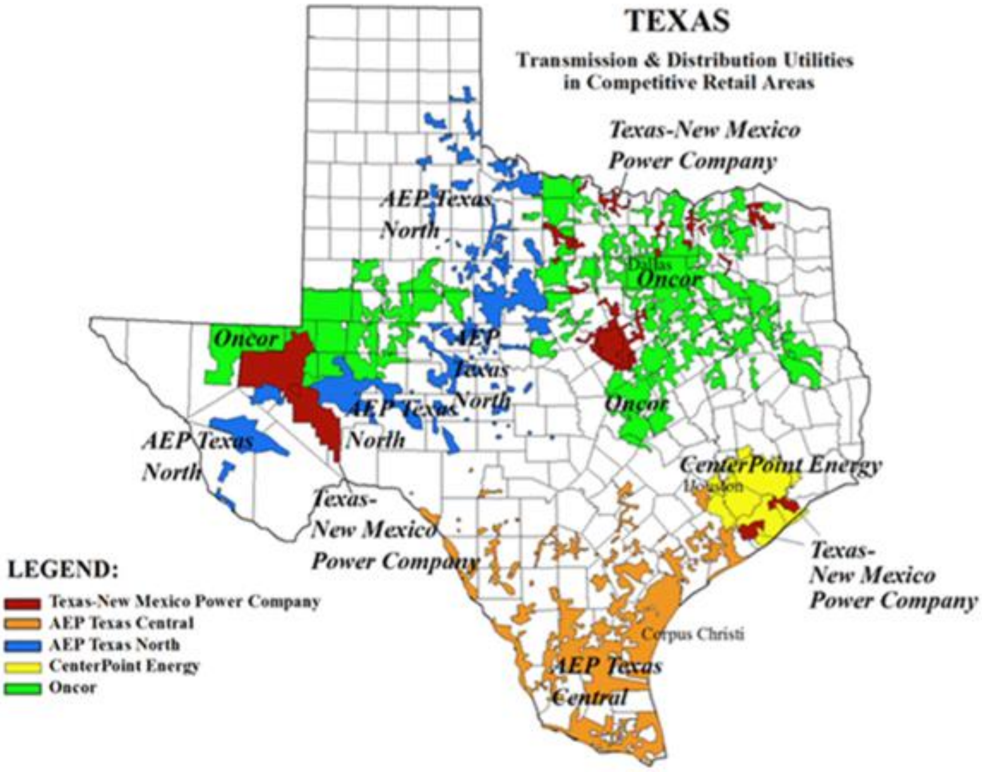


Figure A.1. Areas Initially Opened to Retail Competition. Source: PUCT at: https://www.puc.texas.gov/industry/maps/maps/tdumap.pdf.

At the start of retail competition in 2002, certain constraints were placed upon the prices charged by the five retailers that were successors of former vertically-integrated utilities (then known as the AREPs, or affiliated retail electric providers). After January 1, 2005, the AREPs were allowed to provide alternative prices to their customers, provided these alternative pricing plans did not exceed the “price to beat” (PTB) set by the PUCT. By December 2007, approximately 40 percent of residential customers in areas exposed to retail competition had switched to a competitive retailer – i.e., a retailer other than one that was a successor to one of the former vertically-integrated utilities – or a different AREP. On January 1, 2007, PTB constraints fully expired, removing any regulatory oversight over retail prices. The outcome was an overall reduction in average prices (Zarnikau and Kang, 2009; Swadley and Yucel, 2011).

Before retail choice was implemented in Texas, Direct Energy entered the Texas retail market by purchasing the retail branches of AEP-Texas North and AEP-Texas Central (formerly known as West Texas Utilities and Central Power and Light). Another of the five original AREPs changed ownership when Reliant Energy – a successor of Houston

Lighting and Power Company – was acquired by NRG Energy in 2009.[188] In 2011, Direct Energy acquired another original AREP – First Choice Power, the retail affiliate of Texas-New Mexico Power Company.[189] The last remaining AREP, TXU Energy, was acquired by a group of private investors (led by KKR, TPG Capital, and Goldman Sachs) in 2007. Following a bankruptcy in 2013, TXU Energy and its generation affiliate (Luminant) were renamed as Vistra Energy in 2016.[190]

In recent months, following the merger of NRG Energy and Direct Energy, concerns have been raised over market concentration in ERCOT's retail market. After the completion of the merger on January 2, 2021, NRG Energy and Vistra control about 78% of the *residential* retail market, though concentration in other market sectors (e.g., commercial and industrial market segments) is lower (Brown, et al, 2020).

On the competitive retail side, the 2021 winter event has reduced the number of retailers. Griddy Energy, Entrust Energy, and Power of Texas Holdings have left the market and Just Energy Group has filed for bankruptcy. By February 24, 2021, the number of competitive rate options advertised on the PUCT-administered Power to Choose website had dropped by half.[191] A departure of retailers from the market has occurred in the past,[192] but the number of retailers that have left the market recently is unprecedented.

A.6. Summary: ERCOT History and Current Status

The ERCOT grid and ERCOT the organization have changed considerably since the Texas legislators ordered restructuring of wholesale markets. Wind and solar generation were practically zero in 1999, but amounted to 25% of the 381 terawatt-hours (TWh) of generation in 2020 (Figure A.2) Natural gas generators have provided 40-46% of generation during the last 15 years, while coal generation had declined from 40% in 2010 to less than 20% in 2020. There are currently no plans to build new nuclear power plants in ERCOT.

---

[188] https://en.wikipedia.org/wiki/NRG_Energy; https://www.power-grid.com/td/nrg-energy-to-acquire-reliant-energys-texas-retail-business/#gref

[189] https://www.prnewswire.com/news-releases/direct-energy-to-acquire-first-choice-power-for-270-million-130411228.html

[190] https://www.txu.com/company/why-txu-energy/about-us.aspx; https://www.dallasnews.com/business/energy/2016/11/04/luminant-and-txu-energy-have-a-newly-named-corporate-parent-vistra/

[191] Based on calculations performed by Hen-Hao Tsai, a former researcher at UT-Austin who is now employed by MISO. Communicated via email to Jay Zarnikau on Feb. 24, 2021.

[192] Based on ERCOT's public notices, retailers that have left the market prior to 2021 include: Texas Commercial Energy (2003), Utility Choice Electric (2004), Ampro (2006), Buy Energy (2006), Franklin Power (2005), Blu Power of Texas (2008), Hwy 3 MHP (2008), Sure Electric (2008), Pre-Buy Electric (2008), National Power Company (2008), Abacus Resource Energy (2011), EPCOT Electric (2012), TexRep7 LLC (2012), Reach Energy (2014), Proton Energy (2014), and Reach Energy (2014).

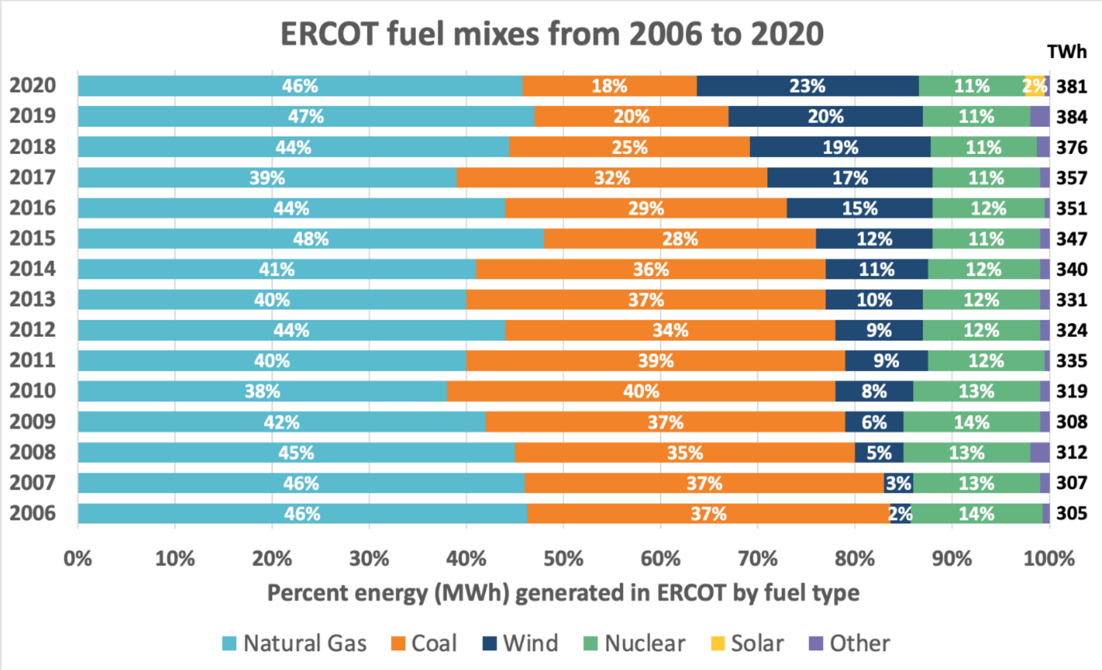


Figure A.2. The percentage of annual electricity generation in ERCOT, by fuel, from 2006-2020

Appendix B. Internal ERCOT Meteorological Discussions Before the Storm

To help forecast electricity demand or "load" and make other preparations for day-to-day grid operations, ERCOT utilizes multiple weather models, NOAA forecasts, as well as data from outside weather vendors to inform their internal predictions about short and long-term weather across the state. Communications between the resident meteorologist and various planning, outage, and resource groups at ERCOT indicate the difficulty in forecasting the onset and severity of Winter Storm Uri of 2021. These day-to-day communications are internal to ERCOT, but ERCOT issues outside communications to market participants to warn of major weather events that could impact market operations.

Of the internal ERCOT emails we reviewed; one written January 28 was the first mention that ERCOT would experience a spate of cold weather. This e-mail noted that February is that hardest month to forecast, but that there was evidence that February 2021 would be colder than normal. Another email on February 1 indicated that a polar vortex was working, but it was likely to be pushed east of Texas. On February 3, an email indicated that there was a good chance that February was going to be the coldest weather of the 2020/2021 winter, but the models used for predictions were varying widely with forecasted lows for Austin varying between 19^{o}F and 53^{o}F on February 8. By February 4 the various models were converging on Dallas and Austin seeing their coldest weather of the year, with a good chance of Houston and possibly for Brownsville also seeing their coldest temperatures of the year. On February 5, the models began to diverge on the timing of when the cold air masses will arrive in Texas. The February 6 weather update compares the coming cold to January 2018 in severity. The February 7 update explained that the models were still 20-30 degrees apart in their temperature predictions with the coldest model showing cold weather similar to January 2018.

By February 8 the models began to trend back together, showing February 14 to be very cold. The meteorologist noted that "[t]his is the most challenging, worrisome forecast since I joined ERCOT…" One of the models indicated a scenario that would rival the weather event of 1989, but the forecasted cloud cover made it hard to believe. Also, there were still tens of degrees difference between the various models, but they were trending to levels equivalent to the extreme cold weather experienced in February 2011. The February 8, 2021 update was the first to mention that there could be significant icing issues with this storm.

The February 9 update indicates that the models were in agreement that February 14 – February 17 would be very cold, but that there was still a 15-20^{o}F difference between them. The February 9 update also noted that there was a high chance of freezing rain in West Texas in the short-term, and that there likely wouldn't be enough time for it to melt before the coldest temperatures arrived. On February 10 some of the models that have been predicting warmer weather began to predict weather closer to the coldest model, and a December 1989-like scenario can't be ruled out. Additional information conveyed on February 10 said that the 2011 February 2 freezing conditions arrived much more abruptly than the anticipated oncoming freezing conditions over the oncoming week of 2021. A February 11 weather update indicated that the event could last as long as February 18.

The February 12 weather update indicated that the forecasts were all trending colder, and that the models were having trouble accurately in predicting snow this late in the winter (mid-February) because there was a lack of historical precedent for snow this late in the winter. The February 12 update further noted that there were continued disagreements between models and vendor-supplied temperature forecasts and that "ERCOT simply hasn't seen anything quite like this – this late into the winter."

On February 13 the weather models were still disagreeing on the severity of the coming cold in some parts of the state, and the ERCOT meteorologist communicated a possibility of a second winter storm that would hit mid-week, bringing more snow. The ERCOT meteorologist also noted that they could not rule out forecasted lows in the mid-teens (degrees Fahrenheit) in the Rio Grande Valley.

The last of the supplied emails, from February 14, discussed that all but one solar farm in ERCOT was likely to receive snow and that the models still had disagreements of between 10-15^{o}F in the severity of the cold over the next few days, making forecasting difficult. In this email, it was also noted that Dallas temperatures on February 14 were currently below the latest forecasted levels.

The internal meteorological communications reviewed appeared to describe a very difficult storm to predict, oh which the intensity wasn't fully realized until just before it happened.

Appendix C. Generator Outages Relative to Time Reaching Freezing Temperature

Another relevant question to ask in assessing the electric grid's ability to withstand freezing conditions is "How long do generators experience freezing conditions before generators experience outages?" That is to ask, if a sub-freezing winter storm arrives in Texas, how much time does it tend to take for power generation to go offline, for any reason?

We display the timing of the February 2021 outages in Figure C.1., with respect to when power plants first reached freezing temperature (0°C or 32°F). Some parts of Texas, for example the panhandle, reached freezing temperatures days before the southern coastal parts of Texas reached freezing temperatures — the figures account for this difference.

Figure C.1 combines the MERRA-2 weather data with ERCOT's publicly reported timing of generator outages as compiled within the "ERCOT's Generator Outage/Derate Visualization App" (EGOVA) dataset that relates the generators to power plants in U.S. government databases with location data.[193] We first associate a MERRA-2 temperature time series with each power plant based on the nearest weather station. Then, starting with the first hour on February 5, we find the first hour with a temperature at or below 0°C, and plot the reported generation outages relative to the time at which the power plant first experienced 0°C.

It is easiest to explain the methodology for the concrete example of the nuclear generator that experienced an outage. ERCOT reported that South Texas Nuclear Project (STNP) generation unit #1 experienced an outage from February 15 at 5:27 am to February 17 at 9:07 p.m., a span of approximately 64 hours. The MERRA-2 weather data suggest that STP reached 0°C at approximately 2 am on February 15. Thus, STP went offline approximately 3 to 4 hours after reaching 0°C, and the figure for Nuclear indicates STP's capacity reduction starting *4 hours after first reaching 0*°C. Similarly, 64 hours after going offline, STP operators brought the generator back online, and the capacity reduction returned to zero at *68 hours after first reaching 0*°C*,* since the generator was at full capacity at that time.

If a power plant experienced a capacity reduction, generation derating, or outage, *before reaching 0*°C, that is reported as a negative value (*before)* the 0-hour on the x-

[193] https://bit.ly/EGOVADatabase

axis. Figure C.1 sums all capacity outages for plants of the same fuel relative to the time they experienced freezing temperatures.[194]

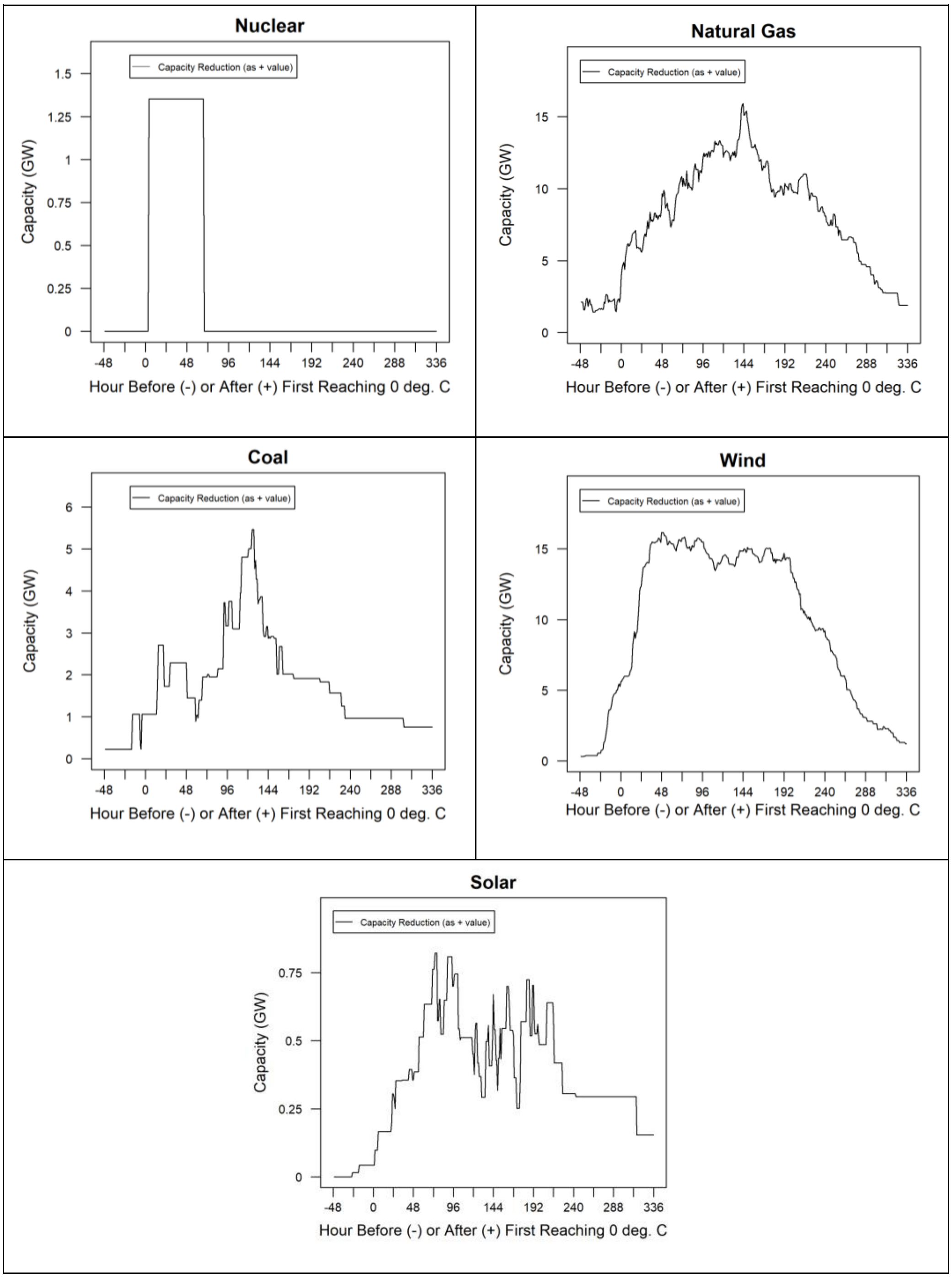


Figure C.1. The capacity reduction (generation outages) for all types of generators relative to when they first experienced 0°C.

[194] That is to say, if two natural gas generators, with capacity reductions of 100 MW and 200 MW, respectively, experienced their outage 3 hours before reaching 0°C at each location, then this would be shown as a 300 MW outage at the x-axis value of –3, for 3 hours before reaching 0°C.

We can draw some conclusions from Figure C.1, but there are many caveats. One takeaway is that the duration of freezing temperatures is important, in addition to the temperatures experienced. Compared to wind and solar outages, the peak coal and natural gas generator outages occur at much longer intervals of time after reaching freezing temperatures. The peak capacity of outages, relative to the time when the plants first experienced freezing temperatures, was approximately 6 days for natural gas plants, 5 days for coal plants, 1 day for wind turbines, and 3 days for solar generators. This result suggests that a multitude of complicating factors might accumulate or occur after many hours at, or below, freezing temperatures to affect natural gas and coal generation. The impacts to wind and solar farms appear to occur relatively quickly, which is consistent with the reporting suggesting that a majority of their outages were related to snow or ice accumulation.

Some of the caveats in the interpretation of Figure C.1 include the lack of other weather data, such as precipitation and wind speed, as well as other factors that caused power generator outages, such as fuel limitations and other mechanical failures. For example, it is possible that the same cold temperatures with dry, rather than wet, conditions could have caused fewer generation outages from all types of generators. Further, generation units experience outages on a regular basis that are independent of the weather.

Appendix D. Texas Natural Gas Balance

Per the U.S. Energy Information Administration (EIA), Texas is the largest energy-producing and energy-consuming state in the U.S., including crude oil and natural gas. In 2020, Texas accounted for 43% of the U.S. crude oil production and 26% of its marketed natural gas production.[195] Texas also consumes more energy (in aggregate) than any other state.

The extreme cold weather from Winter Storm Uri and associated electricity supply disruptions caused serious interruptions in Texas natural gas supply due to freeze offs in field operations in the oil and gas value chain. The storm affected rates of natural gas production and industrial sector consumption with both experiencing their largest monthly declines on record. During the same period, residential consumption reached record highs.

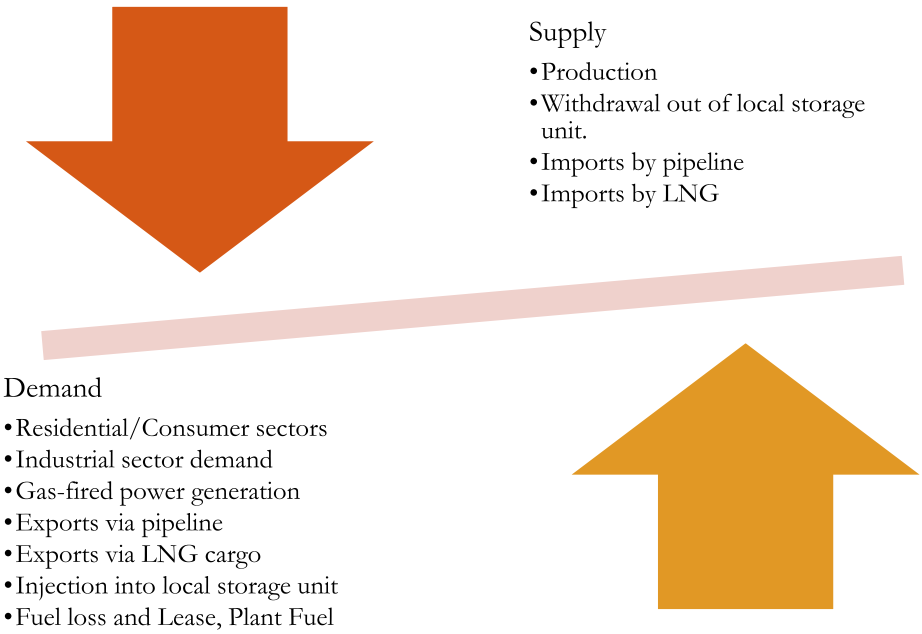


Figure D.1. Overall Natural Gas Balance

To contextualize natural gas operations during the storm and associated blackout, it is important to understand the natural gas balance of Texas (see Figure D.1. Overall Natural Gas Balance). There are three major sectors of the natural gas value chain; production, transmission and distribution. The balance of the market describes the aggregated relation between the supply and demand segments. There are multiple ways to supply a market with natural gas, including local production, local withdrawal from storage, and imports regions. There are also multiple demands for natural gas: including distribution to downstream consumers in individual market segments, injection into underground storage units, and exports to

[195] EIA: Texas - State Energy Profile Overview - U.S. Energy Information Administration (EIA)

other markets. There are five major segments of demand for natural gas – residential, commercial, gas-fired electricity generation, industrial, and transportation.

Figures D.2 and D.3 show the monthly natural gas supply-demand balance[196] in the state of Texas from January 2016 to February 2021. Aggregate natural gas supply in Figure D.1 includes two major supply sources, dry gas production and net storage withdrawal. Dry gas production[197] refers to the process of producing consumer-grade natural gas, after removing nonhydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen), and it does not include any volume used for production at the lease site, or any processing losses. The volumes of dry gas withdrawn from gas storage reservoirs are separate and not considered part of production. Dry natural gas production equals marketed production less extraction loss. Aggregate natural gas demand includes three categories: 1) local gas deliveries,[198] 2) net exported gas,[199] and 3) losses of natural gas in field extraction and processing, as lease and plant fuel, and as pipe loss fuel. Figure D.3 shows an increasing demand for Texas exports of natural gas via pipeline and LNG to other markets.

The aggregated supply side should equal to the aggregated demand side, theoretically. Though in reality, there is often a small balancing item representing any quantities lost and imbalances in the data due to differences among data sources. This balancing item is usually around 0.5-1.5%.

$$Production + Net\ Withdrawl\ from\ Storage =$$
$$Consumption + Net\ Pipeline\ Export + Net\ LNG\ export + (Fuel\ loss + LPF)$$

[196] Figure D.2 – 5 GPCM® Base Case Database as of 2021 Q1 a market simulator for North American Gas and LNG™ by RBAC.

[197] EIA: Definitions, Sources and Explanatory Notes on natural gas.

[198] Including electric generation, residential, and commercial customers

[199] Gas exported Texas via pipeline to other states and Mexico, as well as net exported gas as liquified natural gas (LNG) cargo to international destinations

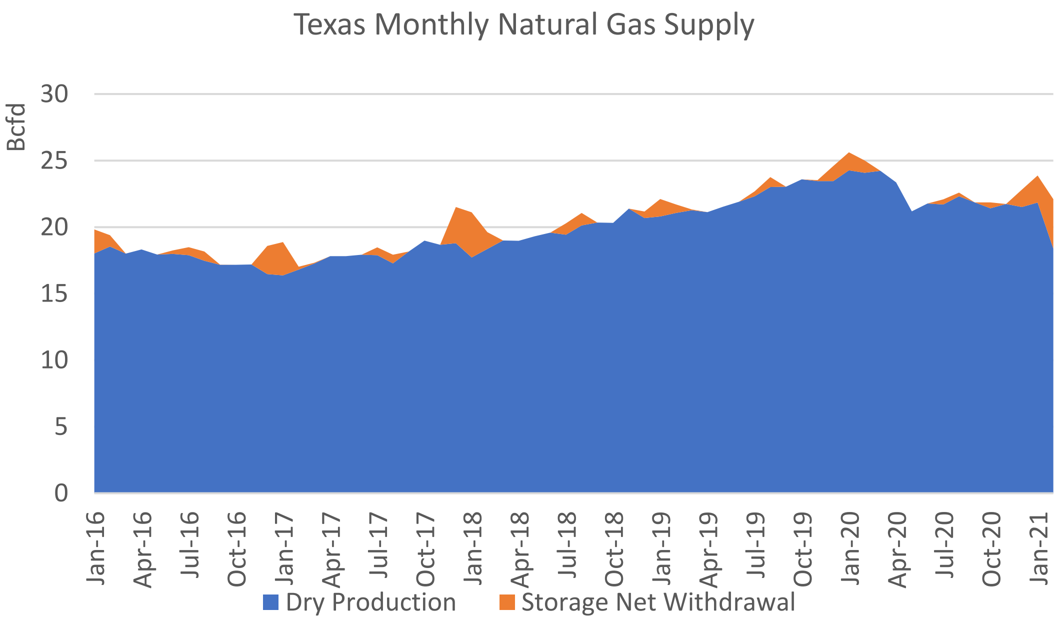


Figure D.2. Texas Monthly Natural Gas Supply (Source: GPCM™)

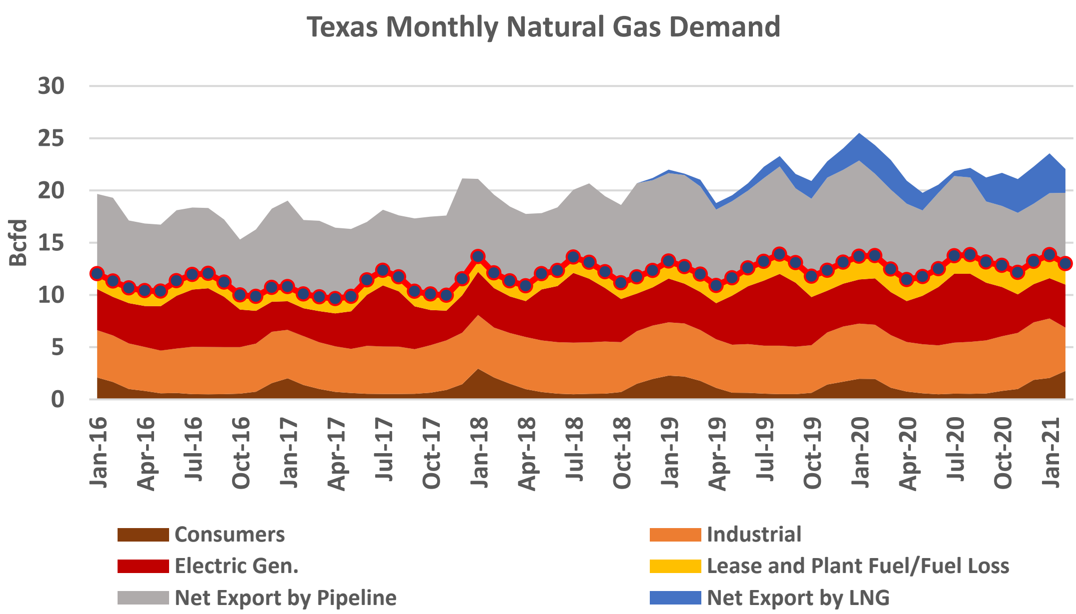


Figure D.3. Texas Monthly Natural Gas Demand (Source: GPCM™)

Appendix E. Other (non-energy) Infrastructures Impacted from Storm: Water and Housing

The winter storm's impacts did not stop with the electricity and gas infrastructure. The storm also directly and indirectly impacted other infrastructures, including water and housing. At one point, up to 12 million Texans[200] were without water or under boil advisories due to either low water pressure or damaged treatment facilities.[201] While property damage was not limited to Texas, the state is expected to file roughly half the insurance claims associated with the winter storm.[202] The Federal Reserve Bank of Dallas estimates that insured losses in Texas alone range between $10 billion and $20 billion. [203] The Dallas Fed estimates that total losses from the storm could approach $130 billion in direct and indirect costs, while other estimates put it as high as $300 billion. [204]

[200] https://www.texastribune.org/2021/02/17/texas-water-boil-notices/

[201] https://www.dailysentinel.com/social_media/article_e3e219d1-e267-513d-848d-10dc3109e595.html.

[202] https://www.wsj.com/articles/winter-freeze-damage-expected-to-hit-18-billion-from-burst-pipes-collapse-roofs-11613757414.

[203] https://www.dallasfed.org/research/economics/2021/0415.

[204] https://www.perrymangroup.com/media/uploads/brief/perryman-preliminary-estimates-of-economic-costs-of-the-february-2021-texas-winter-storm-02-25-21.pdf.