

# **PUSHED TO THE BRINK:**

## **THE 2021 ELECTRIC GRID CRISIS AND HOW TEXAS IS RESPONDING**



by Brent Bennett, Ph.D., Katie Tahuahua, Mike Nasi

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**Texas Public Policy  
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# Pushed to the Brink: The 2021 Electric Grid Crisis and How Texas Is Responding

Brent Bennett, Ph.D., Katie Tahuahua, Mike Nasi

## Executive Summary

Texas is America's energy powerhouse—the top-producing oil and natural gas state in the United States and by far the nation's largest producer and consumer of electricity, accounting for more than 10% of the nation's electricity generation ([U.S. Energy Information Administration \[EIA\], 2021a](#)). When the state suffered days of widespread and catastrophic outages during Winter Storm Uri in February 2021, Texans and the entire nation were shocked. How could the energy state run out of energy?

Most of the reports and analyses on the storm focus on what went wrong during the storm itself, from generation outages to gas supply failures to communication errors. There is plenty to unpack regarding what broke and who is to blame for the various failures, but what is missing from the existing narrative is a complete discussion of the underlying regulatory and market design failures that caused the Texas electric grid to be so unprepared for this storm. Over the past decade, more than \$60 billion has been invested in variable wind and solar generation in Texas ([Advanced Power Alliance, n.d.](#)), while investments in dispatchable power plants, reliability measures, and weather resiliency have been lagging. In fact, since 2015, the region managed by the Electric Reliability Council of Texas (ERCOT), accounting for over 90% of Texas' electricity demand, has lost nearly 5 GW of dispatchable capacity ([EIA, 2021b](#))—that is gas and coal power plants whose output can be varied up and down (dispatched) to precisely match electricity demand. The growth in Texas' electricity demand since 2015 has been entirely met by new wind and solar generation, which now make up a third of ERCOT's electric generation capacity ([ERCOT, 2021h](#)).

The lack of firm or dispatchable generation capacity left Texas wholly unprepared to handle the electricity demand brought on by Winter Storm Uri. Even if the generation outages and gas supply problems caused by the cold weather had been corrected, the ERCOT region would still have suffered widespread outages lasting at least 24 hours. While it is important to address the problems directly related to the storm, imposing weatherization mandates and other regulatory measures without the appropriate market reforms to ensure that electric generators earn the money needed to pay for those mandates will drive them out of business and make future grid failures more likely. The ERCOT market has directed too much investment into variable energy resources while failing to direct enough investment into reliability and resiliency measures, and until that problem is corrected, the reliability of the ERCOT grid will continue to degrade.

## Key Points

- While the weather during Winter Storm Uri was unprecedented in recent Texas history, the problems experienced by the electric grid were predictable based on years of overinvestment in unreliable generation and underinvestment in reliability measures.
- More than \$60 billion in capital investment has flowed into wind and solar generation since the outages in 2011, and those generating resources produced less than 1 GW of power at the height of Winter Storm Uri on the night of February 16, 2021.
- While weatherization and other measures to improve the winter availability of gas and coal generators are necessary, those measures are counterproductive if not done in concert with market reforms that properly compensate those generators for their greater availability relative to wind and solar generation.
- Any new measures the PUC takes to procure or incentivize more backup generation should be paid for by generators that are causing the need for the extra backup power. Requiring ratepayers to pay for those costs will fail to fix the imbalances in the market and lead to spiraling costs.

The Texas Legislature, which was in session during Winter Storm Uri, responded to the problems exposed by the storm with a wide range of legislation, most notably Senate Bill 3, which included broad directives for ERCOT market reforms. Gov. Abbott followed by appointing four new commissioners to the Public Utility Commission of Texas (PUC) and requested that they focus on specific reforms to improve grid reliability, including a firming requirement for wind and solar generators ([Letter from Governor Abbott, 2021](#)).

At the time of this writing, the PUC and ERCOT are moving forward with an initial slate of reforms—including measures to handle the daily variability of wind and solar output and a firm fuel product to incentivize greater winter resiliency—that are largely agreed upon in principle but will require careful implementation and cost allocation ([PUC, 2022](#)). A larger slate of broad market reforms is currently being studied, and it is critical that those reforms address the misdirection of investment flows in the ERCOT market and avoid significantly raising costs to ratepayers.

## Introduction

Beginning on Valentine’s Day 2021, temperatures across Texas plummeted to record lows. Almost the entire state experienced below-freezing temperatures for more than four days and was blanketed with snow. Winter Storm Uri brought the coldest weather Texans had experienced since the 1980s, and the duration of the storm was unprecedented in the last 100 years. Four million Texans lost power, some suffered in the cold for a week or more, and hundreds died from the cold ([Calma, 2021](#)), including an 11-year-old boy who froze to death in his bed.

During and after the storm, the media and policymakers mostly focused on the operational and weather problems that caused so much of the state’s electric generation to go offline. These problems are covered in detail by reports from the Electric Reliability Council of Texas ([ERCOT, 2021d](#)), a study from the University of Texas at Austin ([King et al., 2021](#)) commissioned by the Public Utility Commission of Texas (PUC), and the forensic analysis performed by the Federal Energy Regulatory Commission and the National Electric Reliability Corporation ([FERC, 2021](#)). Most of the outages of coal, gas, and nuclear power plants were caused by frozen equipment, shortages of natural gas, and other equipment failures ([ERCOT, 2021d, p. 18–20](#)). About half the state’s wind turbines were offline due to icing, and some of its solar generation was also snowed over.

What is largely missing from those reports is any discussion of the regulatory and market design failures that led to overinvestment in intermittent wind and solar generation in Texas over the past decade and underinvestment both in reliability measures and in maintaining enough dispatchable generation to meet growing electricity demand. The only widely publicized report prior to this study that covered this problem in detail was from the Texas Section of the American Society of Civil Engineers ([ASCE, 2022](#)). As the summary of the report states, “ASCE Texas Section identified two primary and related problems: 1) a failure to support reliable dispatchable power generation, and 2) the negative impact from sources of intermittent electric power generation” ([p. 5](#)). More than \$60 billion of private investment has flowed into wind and solar generation in Texas over the past decade ([Advanced Power Alliance, n.d.](#)), yet that entire fleet produced less than 5 GW on average during the four days at the height of the storm ([EIA, n.d.-b](#)). Meanwhile, the ERCOT market has lost nearly 5 GW of dispatchable capacity since 2015 ([EIA, 2021b](#)). Many operational problems contributed to the grid failure, but fundamentally, Winter Storm Uri showed that the ERCOT market is suffering from an *investment* problem. Simply mandating more winterization and solving some of the operational problems will not help unless electricity generators have the money to make the necessary changes.

It is important to point out that the ERCOT region never had enough reliable generation capacity to make it through this event without widespread outages. Based on ERCOT’s assessment of thermal power plant outages and wind and solar availability during the storm ([ERCOT, 2021d](#)), if the weather and gas supply problems had been completely resolved, the region would still have seen more than 24 hours of widespread outages. Even if every power plant and wind turbine had been operating at the same level of reliability that they do during the summer, the combination of high demand, low wind speeds, and no sun during the cold mornings and nights meant that there were at least a few hours during the night of Monday, February 15, when blackouts were inevitable ([Bennett, 2021a](#)). It should not be an expectation that the ERCOT grid could endure such a historic storm with no outages—ensuring that level of reliability would be prohibitively expensive—but the storm demonstrated that the ERCOT grid is reaching a breaking point in its reliance on variable generators and that the likelihood of outages will increase in the future without appropriate market reforms.

The timing of Winter Storm Uri was remarkable in that it occurred near the beginning of the 87th Texas Legislature,

which led to a flurry of legislative proposals to fix the problems that the storm exposed. Most of the legislative reforms were condensed into SB 3, and these reforms will be the focus of this paper. While much of SB 3 ([2021](#)) addresses weatherization of power plant and gas supply equipment, emergency communications, and consumer protection, it does contain some key directives for wholesale market reform, most notably ancillary services reforms in Sections 14 and new reliability requirements in Section 18. Other important legislation included SB 2 ([2021](#)) and SB 2154 ([2021](#)) to reform the leadership structure of ERCOT and the PUC and HB 4492 ([2021](#)), SB 1580 ([2021](#)), and HB 1520 ([2021](#)) to securitize the debt incurred by competitive market participants, electric cooperatives, and gas utilities, respectively.

After the resignation of the three previous PUC commissioners, five new commissioners have been appointed, and, following both the legislative mandates in SB 3 and additional directives from Gov. Greg Abbott ([Letter from Governor Abbott, 2021](#)), the commissioners are undertaking an overhaul of ERCOT's wholesale market design to incentivize more investment in dispatchable generation and reliability measures ([PUC, 2022](#)). Several initial reforms—including an Emergency Contingency Reserve Service and voltage support program to balance short-term wind and solar output variability—are already underway at ERCOT, but many details regarding the implementation and cost allocation for those programs are still to be worked out. Another key reform, specifically called for in Section 18 of SB 3 and detailed further in memos by Commissioners McAdams and Cobos ([Garcia, 2022](#)), is a firm fuel product that will incentivize gas storage, firm gas supply contracts, and potentially compensate coal and nuclear plants for the reliability value of their onsite fuel storage.

Longer-term reforms are focused on a backstop reliability service that will purchase additional dispatchable resources for emergencies and on proposals that would require retail electric providers (REPs) and other load-serving entities (LSEs) to “firm up,” that is, to provide a guarantee that they can meet their peak demand with dispatchable generation ([PUC, 2022](#)). A firming requirement for wind and solar generators—one of the four specific reforms Gov. Abbott called for in his July 6 letter to the commissioners ([Letter from Governor Abbott, 2021](#))—is not among the current proposals. The effectiveness of these reforms will hinge on whether they can address the historic imbalance of investment in the ERCOT market toward variable wind and solar generation and away from reliability and resiliency measures and do so without significantly raising costs to

ratepayers. To accomplish that task, the PUC needs to understand the precise nature and causes of the distorted incentives in the ERCOT market and how they were a primary driver of the tragic events of February 2021.

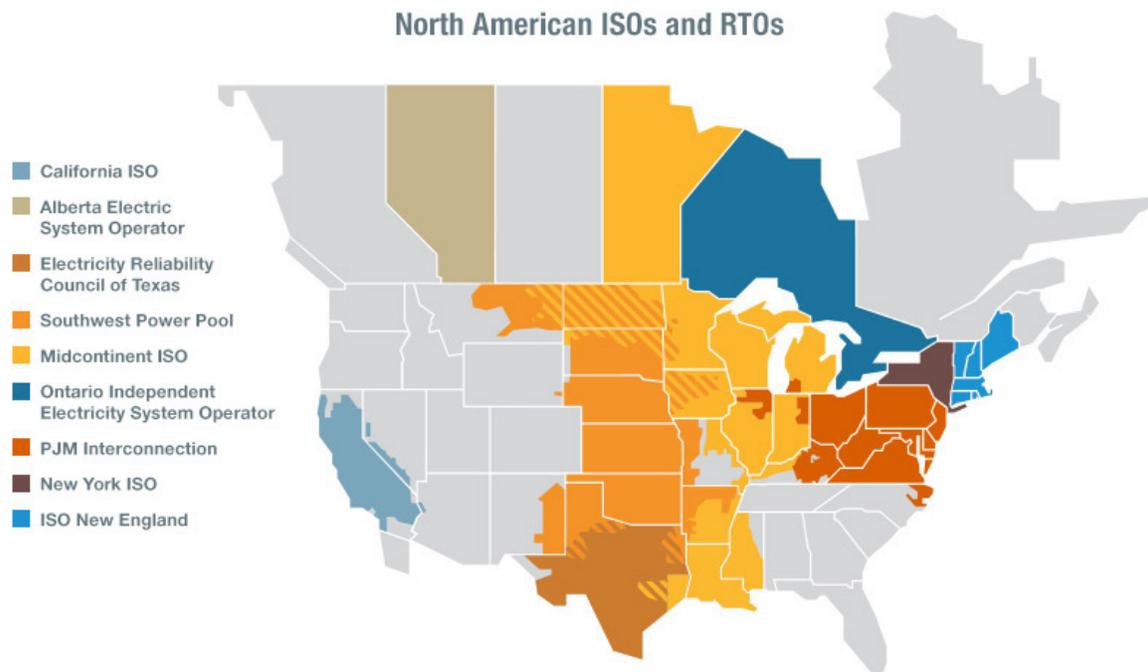
## The Evolution of the ERCOT Electric Market Prior to Winter Storm Uri

Few people thought the energy capital of the nation—an oil and gas powerhouse known all over the world for driving the shale revolution—would run out of power. The story of how millions of Texans lost power during Winter Storm Uri is a complex one, but the root cause of the failures was many years of misdirected market incentives, regulatory policies, and investments that caused the Texas electric grid to underinvest in reliable generation and in the reliability and resiliency measures needed to withstand a storm of Uri's caliber.

This story begins decades prior to February 2021 with many of the decisions that led to the current Texas market design, which in turn made the market vulnerable to the distortions caused by subsidies and short-sighted regulatory actions. Those distortions, and the increasing volatility of prices due to greater penetration of wind and solar generation, were significant causes of the lack of investment in dispatchable generation and greater weather resiliency during the past decade, which in turn was a root cause of many of the problems experienced during Winter Storm Uri.

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for about 26 million customers, representing 90% of the electricity produced and consumed in the state of Texas ([ERCOT, 2021g](#)) and more than 10% of U.S. electric demand ([EIA, 2021a](#)). ERCOT is a 501(c)(4) nonprofit entity, overseen and regulated by the Public Utility Commission of Texas (PUC) and responsible for ensuring system reliability and managing the flow of electricity across the grid. Pursuant to the Public Utility Regulatory Act (PURA), [Texas Utilities Code, Sec. 39.151](#), ERCOT's obligations are to

ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms; ensure the reliability and adequacy of the regional electrical network; ensure that information relating to a customer's choice of retail electric providers [REPs] is conveyed in a timely manner to the [appropriate individuals]; and ensure that electricity production and delivery are accurately

**Figure 1***Geographic Extent of Independent System Operators in the U.S. and Canada*

Note. Reproduced from *Maps and Diagrams*, ISO New England, n.d. (<https://www.iso-ne.com/about/key-stats/maps-and-diagrams/#isos-rtos>).

accounted for among the generators and wholesale buyers and sellers in the region.

In short, the PUC sets the rules for how the electric grid and the electric market will operate, pursuant to the statutes passed by the Legislature, while ERCOT implements those rules and manages the market.

A unique feature of the ERCOT market is that it is wholly contained within Texas and, with a few limited exceptions, is not connected to neighboring ISOs. Since transactions in the ERCOT market are purely intrastate, the market is virtually free from regulation by the Federal Energy Regulatory Commission (FERC) and wholly regulated by the PUC. This situation is in stark contrast to other ISOs, which must answer to regulatory bodies in multiple states and to FERC. The ERCOT market evolved this way primarily because, as municipal and rural utilities in Texas began to interconnect over the course of the 20th century and trade electricity, there was not enough incentive to connect to utilities in other states versus simply building more power plants locally. Texas' vast geography, ample local resources, and growing electricity demand have enabled the ERCOT market to continue flourishing while avoiding

making connections to other markets and incurring additional regulatory burdens.

Prior to 1975, municipalities in Texas regulated their electric utility service and rates, but the 64th Texas Legislature enacted PURA and created the Public Utility Commission of Texas with the authority to regulate the rates and services of electric utilities. The purpose of PURA was to establish a comprehensive public utility regulatory framework to assure just and reasonable rates, operations, and services for both the consumers and the utilities. However, due to various regulatory and economic factors, vertically integrated utilities' monopolies within their service territories continued throughout the state until deregulation of the vast majority of the Texas wholesale and retail electric markets in the mid-to-late 1990s.

### **Deregulation of the Texas Wholesale and Retail Electric Markets**

In 1995, the 74th Texas Legislature concluded that the development of a competitive wholesale electricity market that allowed for increased participation by both utilities and certain non-utilities was in the public interest ([Texas Utilities Code, Sec. 31.001](#)). Consequently, the wholesale

electric market was deregulated, and any utility that owned or operated transmission facilities was required to provide wholesale transmission service at rates, terms of access, and conditions that were comparable to the rates, terms of access, and conditions of the utility's use of its own system. The PUC was required to ensure that utilities provided nondiscriminatory access to transmission service for qualifying facilities, wholesale generators, power marketers, and public utilities.

Deregulating the wholesale power market and requiring all utilities owning transmission lines to provide open access to their wires to transport wholesale power led to the establishment of the “postage stamp” rate ([Cities Aggregation Power Project, 2009, p. 10](#)), a uniform charge for the wheeling of electricity across the interconnected transmission system regardless of the distance traveled or the utility systems used to transmit that power. These decisions led to what this paper will call a “socialized” transmission system in which all consumers pay a flat fee, called a transmission cost of service (TCOS), to support the operations of the transmission and distribution utilities (TDUs). There are five primary TDUs in the ERCOT market, each with its own service area and rates that the PUC sets based on cost-recovery principles ([PUC, 2019, p. 16](#)). In other words, while the generation of electricity in Texas is largely deregulated, the transmission and distribution of electricity is still fully regulated and monopolized.

In 1999, the 76th Texas Legislature determined that

the production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that the public interest in competitive electric markets requires that ... electric services and their prices should be determined by customer choices and the normal forces of competition. ([Texas Utilities Code, Sec. 39.001](#))

While transmission and distribution services remained regulated, the Texas Legislature required the vertically integrated utilities in the ERCOT market to “unbundle” by January 1, 2002, separating their business operations into three distinct entities: power generation companies (PGCs), retail electric providers (REPs), and transmission and distribution utilities (TDUs). The PGCs own and operate the electric power plants and sell power into the deregulated wholesale power market.

After January 1, 2002, no PGC, including their affiliates, could own more than 20% of the generating capacity in any

## The volatility and uncertainty of wholesale prices are fundamental causes of the underinvestment in dispatchable generation and weather resiliency in the ERCOT market over the past decade.

power region in order to prevent market abuse and ensure competition. REPs purchase wholesale power from the PGCs, re-sell the power to customers, and are responsible for all interactions with the customer, including billing the customer for transmission and distribution services and for purchased power costs. The regulated TDUs own and operate the interconnected transmission system and distribution systems required to transport power from the PGCs to all customers within a certain geographical area. The vertically integrated utilities subject to unbundling were authorized to accomplish the required separation either through the creation of separate nonaffiliated companies, separate affiliated companies owned by a common holding company, or through the sale of assets to a third party.

Municipally owned utilities (MOUs) and rural electric cooperative utilities were exempt from unbundling but could choose to opt in to deregulation. Vertically integrated utilities operating in areas of the state outside the ERCOT grid were not required to unbundle unless they met certain requirements. The two largest metropolitan areas, Houston–Galveston and Dallas–Fort Worth, chose to unbundle their MOUs, while the other two major metropolitan areas, Austin and San Antonio, continue to have vertically integrated MOUs, Austin Energy and City Public Service of San Antonio (CPS Energy).

While cooperatives and MOUs were allowed to opt out of retail competition, it is important to note that, because of the interconnected nature of the ERCOT grid, neither MOUs nor cooperatives have the option of “opting out” of wholesale competition. They are subject to ERCOT load shed requirements and market pricing rules, which puts them in the unique position of owning and operating generation to meet the needs of their members but having that generation subject to call by the entire grid. In emergency conditions, this arrangement means that the MOUs and cooperatives may be protected from price blowouts if they own sufficient generation to cover their needs, but they are

still subject to load shed requirements imposed by ERCOT. This was the case during Winter Storm Uri, where some generation and transmission cooperatives and MOUs were forced to cut power to some of their members even though they had sufficient generation to cover the entirety of their power needs ([Texas Senate, 2021a, 2:54:00](#)).

A key feature of the deregulated ERCOT market is that it is an “energy-only” market, where electricity prices are the sole means for compensating power plants. In most other electricity markets, power plants are given capacity payments to remain in the market and ensure that the system has enough generating capacity to meet peak demand. There is both a real-time market with discrete prices down to 15-minute intervals and a day-ahead market. One feature of the real-time market that has received much attention following Uri is the administrative price adder called the Operating Reserve Demand Curve (ORDC), which is designed to compensate generators for being online during tight conditions to help avoid emergency conditions ([PUC 2021a, p. 18](#)). However, while the real-time and day-ahead markets are important parts of the overall ERCOT market, most retail providers choose to procure a large majority of their energy through bilateral contracts or through futures markets such as those operated by the Intercontinental Exchange ([ICE, n.d.](#)). These markets help set longer-term forward prices and create the necessary conditions for investment in large power plants that will last decades.

The energy-only market has worked well to drive inefficiencies out of the market and keep prices down. Between 2001 and 2020, average retail electricity prices in Texas rose 13% on a nominal basis, in contrast to a 45% rise in average retail prices across the U.S. ([EIA, n.d.-a](#)). Plummeting natural gas prices due to the shale revolution led to a decline in retail prices in 2008. However, the increasing penetration of subsidized and intermittent wind and solar generation in the ERCOT market, while helping to keep wholesale prices low, is also driving greater volatility in market prices ([Potomac Economics, 2021, p. 19](#)), detaching price signals from demand curves, and increasing the reliance of dispatchable generators on scarcity conditions to generate a profit ([p. 72](#)). The volatility and uncertainty of wholesale prices are fundamental causes of the underinvestment in dispatchable generation and weather resiliency in the ERCOT market over the past decade.

### The Evolution of the ERCOT Generation Mix From 2001 to 2021

Given Texas’ abundance of natural gas, its electric generation mix has long been dominated by gas power plants. As

of 2001, at the beginning of deregulation in Texas, natural gas accounted for more than half of the state’s annual electricity generation ([EIA, 2021a](#)). Whether mined in state or imported from states such as Wyoming, coal was a close second at the time, providing about 36% of the state’s electricity. There are two nuclear power plants in Texas, which together provided about 10% of the state’s electricity mix. Wind and hydropower were nominal contributors to the state’s generation mix, a little more than 0.3% each, and solar was virtually nonexistent.

Since that time, a combination of state and federal policies has driven an explosive growth in wind generation in Texas. Most significant among these policies is the federal Production Tax Credit (PTC), which provides the owners of wind generation a tax credit of up to \$23/MWh and often forms the foundation of financing agreements that make new wind construction economically feasible. Other forms of federal support, including direct payments to new wind developments, were instituted as part of the 2009 federal stimulus package ([Bennett et al., 2020](#)). Even as the 2009 stimulus programs expired, falling costs to build and install wind turbines and the continuation of the PTC have continued the wind boom, as shown in **Figure 2(a)**. By 2020, wind accounted for 20% of electricity generation in Texas ([EIA, n.d.-c](#)) and 23% in the ERCOT market ([ERCOT, n.d.-a](#)).

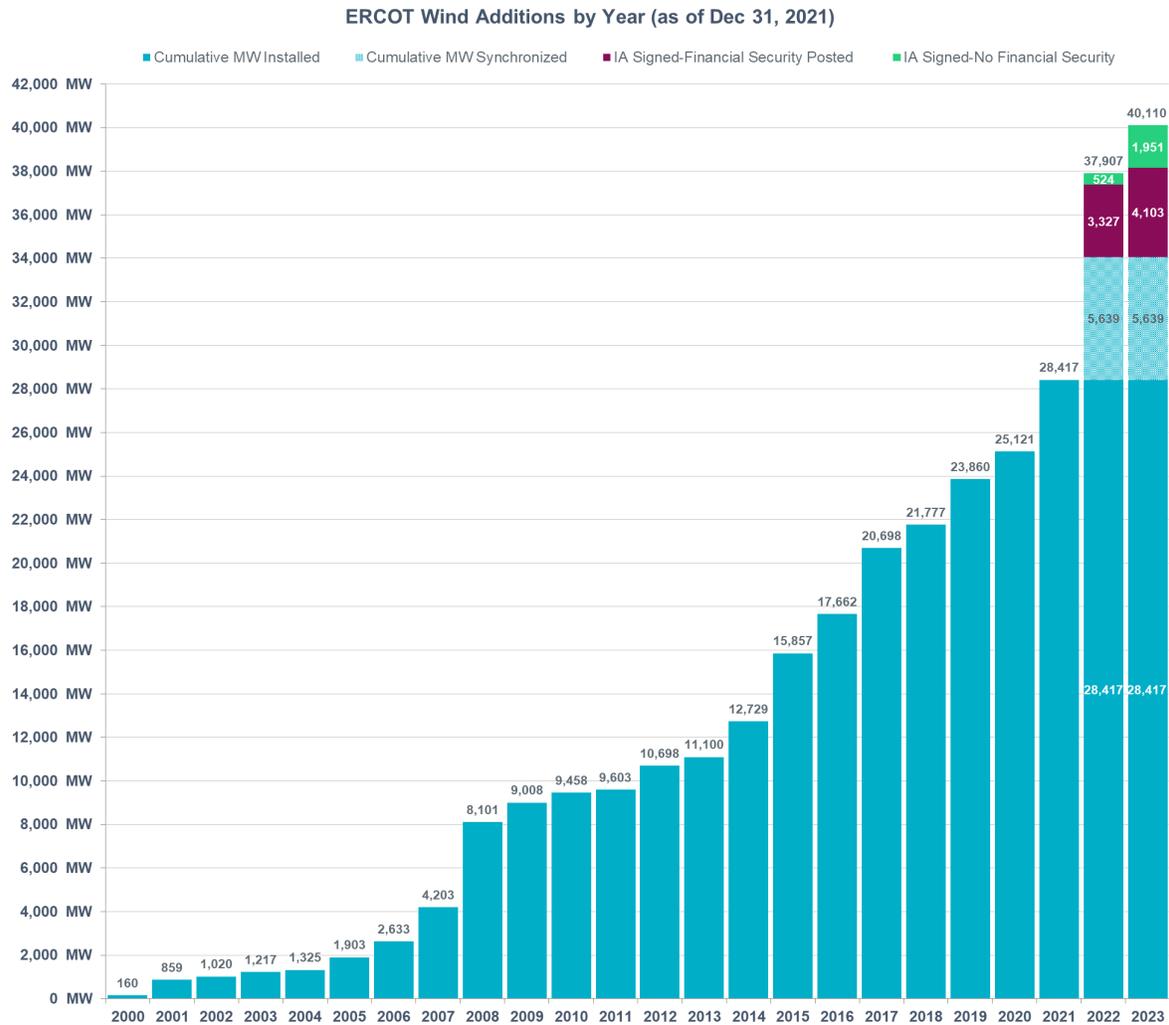
State policies have also played a significant role in fostering wind development. Most crucial was the creation of the Competitive Renewable Energy Zones (CREZ) in 2005, which authorized the creation of a new network of transmission lines with the primary purpose of facilitating the buildout of new wind and solar generation in West Texas by providing a means for that electricity to reach the major cities in East Texas ([SB 20, 2005](#)). That program was estimated to cost \$6.9 billion ([PUC, 2015, p. 60](#)) and is entirely paid for by Texas ratepayers through the TCOS fee. The same bill that created the CREZ program, SB 20, also boosted the state’s Renewable Portfolio Standard to 10% by 2025. That goal was easily surpassed by 2016 with wind generation alone ([EIA, n.d.-c](#)). Finally, the Legislature made wind and solar projects eligible for property tax abatements through the Chapter 313 program in 2001, which dramatically reduces the largest state tax bill that wind and solar developers pay.

Solar installations remained very limited in Texas until 2017 but installed solar capacity has now reached more than 8 GW and is forecast to reach 24 GW by the end of 2023 ([ERCOT, 2021i](#)). Three factors are contributing to

the rapid growth of solar in Texas. First, the falling capital costs of solar projects (Lazard, 2021, p. 9), combined with the continuation of the Investment Tax Credit (ITC), which subsidizes up to 30% of the capital cost (Bennett et al., 2020, p. 6), have made new solar projects competitive in the ERCOT market. Second, the proliferation of wind generation, which tends to produce the least during the

middle of the day in the summer, pushed peak prices to earlier in the day, making it more feasible for solar projects to capture those prices. Finally, the PUC increased the range of conditions during which the ORDC is in effect (Potomac Economics, 2020, p. ii), and, since the sun tends to be shining during hot summer days when the ORDC is

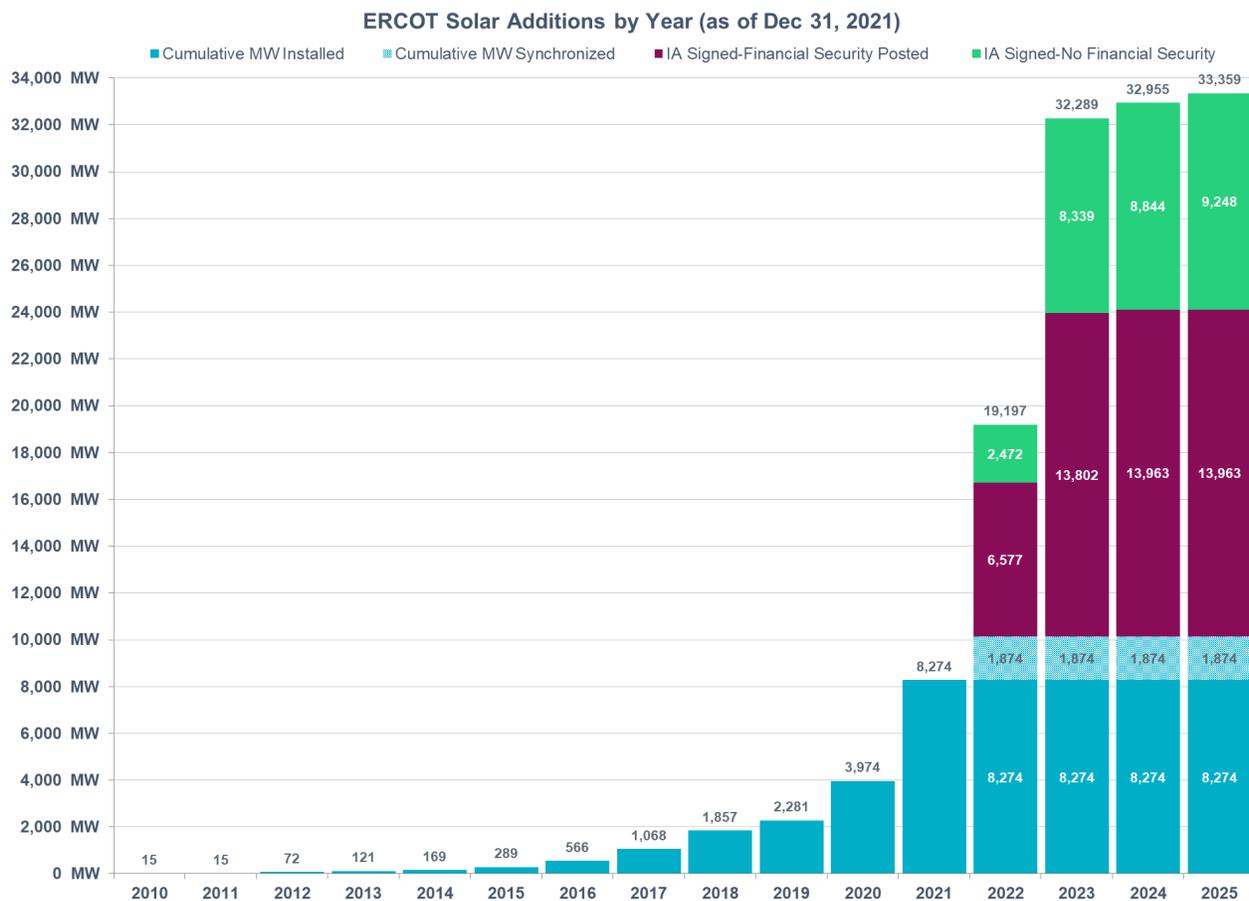
**Figure 2(a)**  
 ERCOT Wind Additions by Year From 2000 to 2023, Actual and Planned



- Notes:
- The data presented here is based upon the latest information provided to ERCOT by resource owners and developers and can change without notice.
  - Installed capacities are based on nameplate rating of the commercially operational generation and reflect retirements or rating changes due to facility expansions or repowering as these occur.
  - Cumulative MW Installed does not include Private Use Network (PUN) units.
  - Note that Installed capacities in ERCOT's Operations reports (such as for example Hourly Wind Output Reports) also include capacities for which Synchronization to ERCOT grid has been approved (Part 2 Approval of the Commissioning Checklist) but not yet Approved for Commercial Operation.
  - Installed capacities include only wind facilities that have registered with ERCOT (Those larger than one megawatt and supply power to the ERCOT system.)
  - Distributed Generation Resources (DGRs) are Resources connected to the distribution system that are greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator, or are greater than one MW and are registered as a Generation Resource to participate in the ERCOT markets.
  - This chart reports annual planned units with projected Commercial Operations Dates throughout the calendar year. In contrast, ERCOT's Capacity, Demand and Reserves (CDR) report shows planned capacity projected to be commercially available on or before the start of the Summer and Winter Peak Load seasons.
  - Financial security posted for funding interconnection facilities does not include CREZ security deposits, which are refunded to the Interconnecting Entity when an IA is signed.
  - Projects that have prior-year Projected CODs that have not been met, and for which ERCOT has not received COD updates, appear as planned projects for the subsequent year.
  - Cumulative MW Synchronized pertains to projects that ERCOT has approved to generate energy for the grid but have not passed all qualification testing necessary to be approved for participation in ERCOT market operations.

Note. Reproduced from *Capacity Changes by Fuel Type* [Excel charts], "ERCOT Wind Additions by Year," Electric Reliability Council of Texas, 2021 ([https://www.ercot.com/files/docs/2022/01/06/Capacity\\_Changes\\_Fuel\\_Type\\_Charts\\_December\\_2021.xlsx](https://www.ercot.com/files/docs/2022/01/06/Capacity_Changes_Fuel_Type_Charts_December_2021.xlsx)).

**Figure 2(b)**  
 ERCOT Solar Additions by Year From 2000 to 2023, Actual and Planned



- Notes:
- The data presented here is based upon the latest information provided to ERCOT by resource owners and developers and can change without notice.
  - Installed capacities are based on nameplate rating of the commercially operational generation and reflect retirements or rating changes due to facility expansions or repowering as these occur.
  - Cumulative MW Installed does not include Private Use Network (PUN) units.
  - Installed capacities include only solar facilities that have registered with ERCOT (Those larger than one megawatt and supply power to the ERCOT system.)
  - Distributed Generation Resources (DGRs) are Resources connected to the distribution system that are greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or are greater than one MW and are registered as a Generation Resource to participate in the ERCOT markets.
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  - Cumulative MW Synchronized pertains to projects that ERCOT has approved to generate energy for the grid but have not passed all qualification testing necessary to be approved for participation in ERCOT market operations.

Note. Reproduced from *Capacity Changes by Fuel Type* [Excel charts], "ERCOT Solar Additions by Year," Electric Reliability Council of Texas, 2021 ([https://www.ercot.com/files/docs/2022/01/06/Capacity\\_Changes\\_Fuel\\_Type\\_Charts\\_December\\_2021.xlsx](https://www.ercot.com/files/docs/2022/01/06/Capacity_Changes_Fuel_Type_Charts_December_2021.xlsx)).

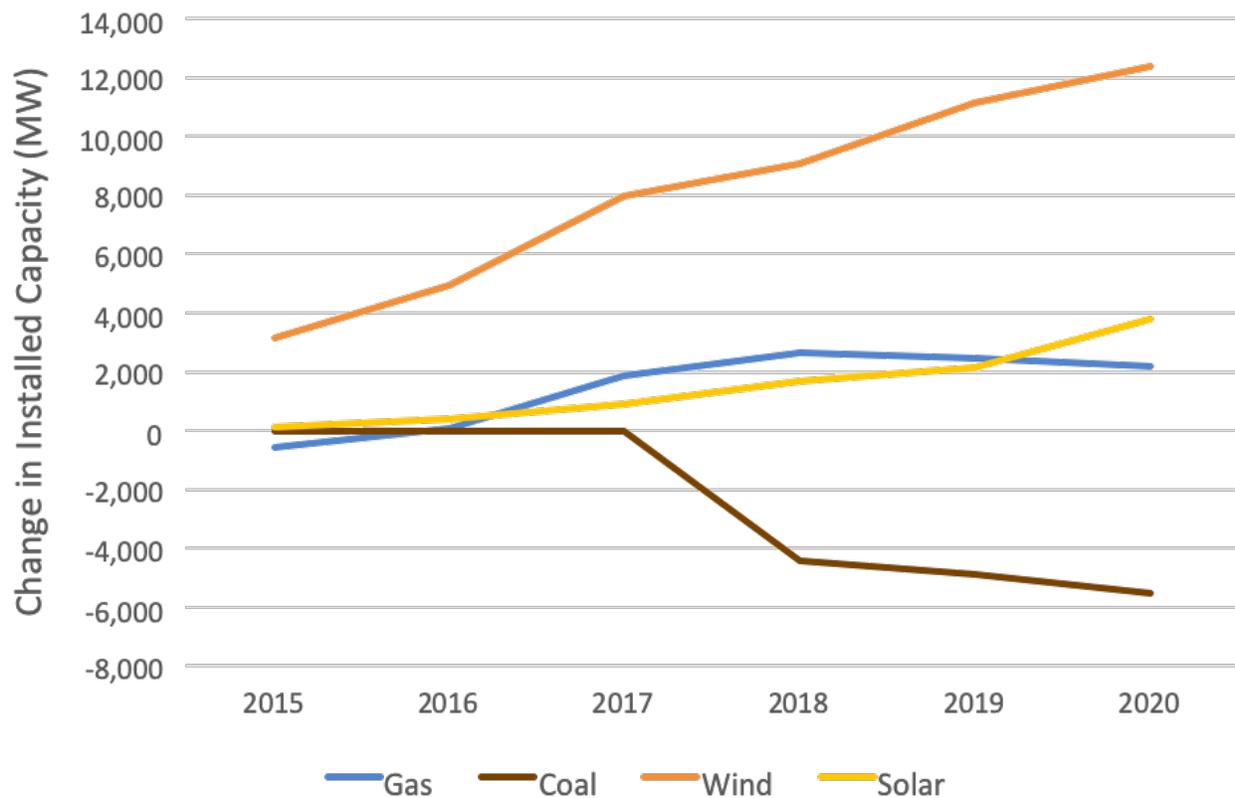
most likely to be in effect, solar developers have bet on that change increasing their potential revenues.

Aside from these incentives, the geography of Texas and the design of the ERCOT market also favor wind and solar development. The lack of vertically integrated utilities and long regulatory approval processes, combined with transmission costs that are entirely paid by ratepayers and the availability of cheap land, favors new entrants to the market. Texas also has abundant wind and solar resources and growing demand, which ensures wind and solar developers

will be able to produce a lot of electricity and have customers to buy it. Finally, ERCOT's energy-only market design, in which generation resources can bid into the market on an as-available basis with no capacity requirements, is particularly well suited to the business models of wind developers. With zero fuel costs, wind generators can sell electricity at near-zero or even negative prices and still profit from the PTC. These favorable forces have led to more than \$60 billion in wind and solar investments in ERCOT ([Advanced Power Alliance, n.d.](#)).

**Figure 3**

Changes in Annual Installed Capacity of Natural Gas, Coal, Wind, and Solar Since 2015



Note. Data from *Capacity Changes by Fuel Type* [Excel charts], “ERCOT Solar Additions by Year,” Electric Reliability Council of Texas, 2021, ([https://www.ercot.com/files/docs/2022/01/06/Capacity\\_Changes\\_Fuel\\_Type\\_Charts\\_December\\_2021.xlsx](https://www.ercot.com/files/docs/2022/01/06/Capacity_Changes_Fuel_Type_Charts_December_2021.xlsx)) and *Preliminary Monthly Electric Generator Inventory*, U.S. Energy Information Administration, 2021 ([https://www.eia.gov/electricity/data/eia860m/xls/november\\_generator2021.xlsx](https://www.eia.gov/electricity/data/eia860m/xls/november_generator2021.xlsx)).

This buildout of wind and solar has primarily come at the expense of coal and even some baseload natural gas combined-cycle power plants. From 2015 to 2020, Texas’ population grew by over 1.7 million ([Federal Reserve Bank of St. Louis, 2022b](#)), the state’s gross domestic product expanded by over \$200 billion ([Federal Reserve Bank of St. Louis, 2022a](#)), and electricity demand grew by 5% ([EIA, 2021a](#)). However, during this period of massive growth, the ERCOT region saw 5.5 GW of coal and 4.8 GW of natural gas retirements, with many of those plants retiring before their expected date ([EIA, 2021b](#)). Only 5.5 GW of new gas generation was built over that time, for a net loss of 4.8 GW of thermal capacity, or about 6% of total installed thermal capacity. In essence, the gap between the state’s electricity demand and its thermal generating capacity has grown by more than 10%, and that gap has been met entirely by new wind and solar generation. The gap would be even larger—and the risk of outages higher—if

not for the COVID-19 pandemic reducing the growth in electricity demand in 2020 and 2021 compared to the 2015–2019 trend.

The lack of awareness about this growing gap between electricity demand and thermal generating capacity in ERCOT is compounded by how ERCOT calculates and publishes its reserve margins. ERCOT’s *Summer 2021 Seasonal Assessment of Resource Adequacy* (SARA) shows 87 GW of available resources to meet 77 GW of projected peak demand ([ERCOT, 2021e, p. 2](#)). However, those numbers are based on the total installed capacity of thermal generation in ERCOT and the average output of wind and solar resources during peak demand hours. It is necessary to continue to the next table, titled “Reserve Capacity Risk Scenarios,” to get a more accurate view of the risks to the system ([p. 3](#)). Average outages of thermal power plants in the summer total about 3.6 GW, and wind output can fall

6.6 GW below its average. Therefore, any situation combining normal thermal outages, low wind output, and normal summer peak demand could put the grid at risk of outages.

In summary, the shift away from dispatchable fossil fuel generators and toward intermittent wind and solar has set the stage for an increasing risk of outages in any situation combining high demand with low wind and solar generation. This increasing risk was first realized when Texas experienced a level 1 Energy Emergency Alert (EEA1) on August 13 and August 15 of 2019 ([Utility Dive, 2019](#)), which required conservation measures but not forced outages to balance the grid. An emergency may have occurred again on August 14, 2020, if not for reduced economic activity due to the COVID-19 shutdowns, which led to 500 MW less peak demand than what was experienced in 2019 ([Potomac Economics, 2021, p. i](#)). Winter Storm Uri simply exposed this problem to its fullest extent.

During and after Winter Storm Uri, media attention focused on the numerous operational failures that manifested, from gas shortages to equipment freezing to wind turbine icing. However, even if generation outages had been minimized and gas supply shored up, the ERCOT region would likely still have experienced outages lasting at least 24 hours. The loss of dispatchable generation capacity in ERCOT over the past several years made it inevitable that the level of demand experienced during Uri, combined with the low availability of wind and solar resources at the height of the storm, would lead to widespread outages. A storm of Uri’s magnitude should be expected to cause some outages, but the storm clearly exposed the fundamental market design problem facing Texas regulators, namely the lack of market incentives to invest in reliable generation and weather resiliency and the extreme incentives to invest in variable generation that undermines the economics of reliable generation.

If the current market structure remains unchanged, future storms of lesser magnitude will be more and more likely to cause outages, and given the years that it takes to implement market design changes, the market design issues must be addressed now.

Seeing that the operational problems and resource adequacy issues each deserve close attention, the next section will summarize the various causes of generation outages during the storm, and the following section will examine how the storm exposed the ERCOT grid’s shortage of firm generation.

### What Happened During Winter Storm Uri

Although Texas has seen the level of widespread cold weather and winter precipitation during Winter Storm Uri in the past, the duration and extent of cold weather, spanning nearly 10 days with several days entirely below freezing, is unprecedented in the past 100 years. The extreme weather led to failures across the entirety of the electricity supply system, from the natural gas supply network to power plants to the transmission and distribution network.

However, even if the weather and operational problems had been solved, the ERCOT region would likely still have experienced outages lasting at least 24 hours. Ultimately, the root causes of the outages are the problems with the ERCOT market outlined in the previous section and the lack of market incentives to invest in reliable generation and weather resiliency. This section will summarize the various causes of outages during the storm, and the next section will examine how they are tied back to the root cause of misdirected investment in the ERCOT market.

**Table 1**

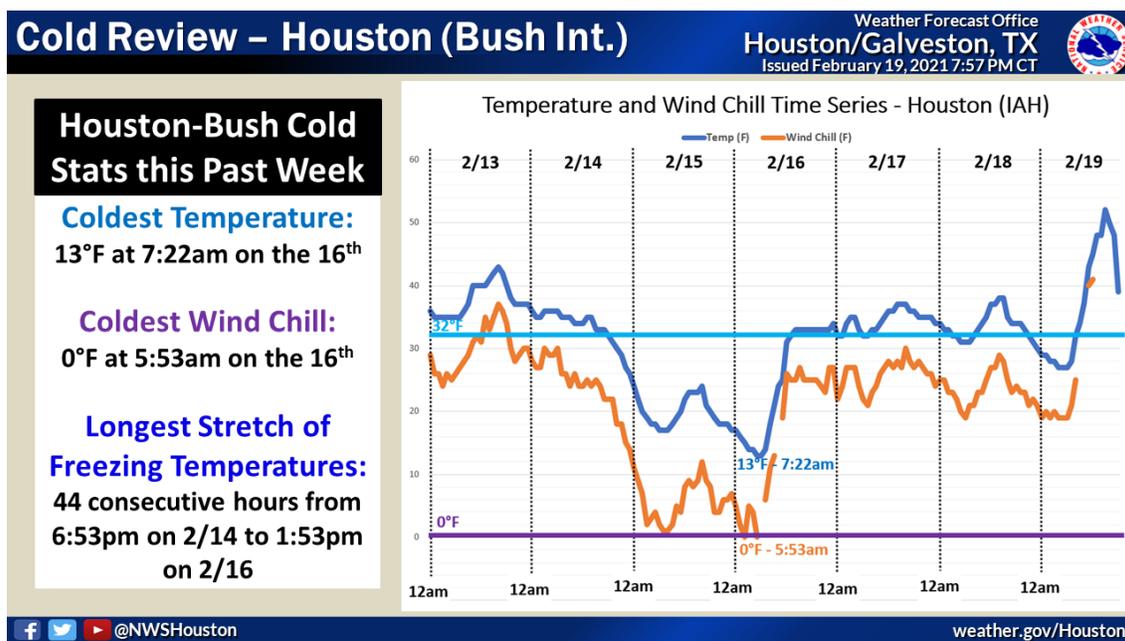
*Lowest Temperatures in Dallas, Houston, and San Antonio in 1983, 1989, 2011, and 2021 (°F)*

	December 1983	December 1989	February 2011	February 2021
Dallas	5	-1	13	-2
Houston	11	7	21	13
San Antonio	11	6	16	6

*Note.* Data from “NOWData - NOAA Online Weather Data,” National Weather Service, n.d. (<https://www.weather.gov/wrh/Climate?wfo>).

**Figure 4**

Temperatures at Houston–Bush International Airport February 13–19, 2021



Note. Reproduced from *Valentine's Week Winter Outbreak 2021: Snow, Ice, & Record Cold*, National Weather Service, n.d. (<https://www.weather.gov/hgx/2021ValentineStorm>).

### How Unique Was the Weather During February 2021?

The most recent comparison to Winter Storm Uri is the winter storm of February 2011, which saw rolling outages for a few hours across much of the state and significant winter precipitation. However, temperatures during Uri were much colder than in 2011. Consequently, the best comparisons are winter storms in 1983 and in 1989, which saw temperatures fall into the single digits or below zero Fahrenheit across much of the state. Notably, only minor rolling outages were experienced during the December 1989 storm (King et al., 2021, p. 71).

Figure 4 shows the temperature in the Houston area throughout the week of Winter Storm Uri. High temperatures in Houston in February are usually in the mid-60 Fahrenheit, with lows in the mid-40s, so the deviations from normal are greater than 30°F throughout the entirety of the week, with no recovery until February 19. Normally in Texas, temperatures are well above freezing within a day or two after a winter storm, but this event saw cold weather for several days prior to February 15 and the persistence of below-freezing temperatures for four days after that.

Therefore, duration is the major differentiator of this event from the similarly cold weather that occurred in the 1980s.

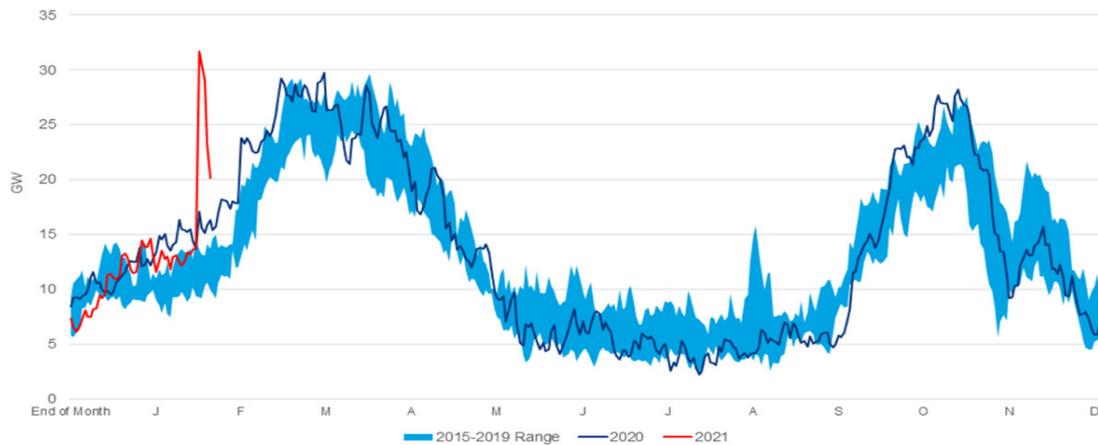
The duration of the storm had a significant impact on infrastructure and fuel supply. Natural gas supplies were already stretched thin prior to February 15, leaving no breathing room once temperatures plummeted another 15 to 20 degrees and demand for electricity shot up. The ability of crews to make repairs to power plants, pipelines, transmission lines, etc., was hindered by poor road conditions. Equipment that was frozen took days to thaw out. These weather impacts were the primary reason that what might have been one day of electricity outages turned into multiple days for much of the state. However, the problems that were exposed by Uri run much deeper than what can be directly tied to the weather.

### Preparations Made by ERCOT, Market Participants, and State Regulators

While long-range weather forecasters had been forecasting a late winter storm for the central United States for some time, the first clear signs of troublesome weather coming the week of February 15 began to appear as the calendar turned to February. On February 8, ERCOT issued an

**Figure 5**  
Thermal Generation on Outage in ERCOT, 2015 to 2021

## Thermal generation on outage in ERCOT



Source: ERCOT

Note. Reproduced from *Breaking Down the Texas Winter Blackouts: What Went Wrong?* By M. O'Shea, R. Goel, and R. Miller, Wood Mackenzie, February 19, 2021 (<https://www.woodmac.com/news/editorial/breaking-down-the-texas-winter-blackouts>).

Operating Condition Notice for an extreme cold weather event ([Magness, 2021, p. 9](#)), canceled or delayed maintenance outages for transmission, and sought to return power plants to service that were undergoing maintenance ([p. 8](#)). In total, about 13 GW of thermal generation was offline prior to February 14, which was in line with the 2015–2020 historical range, as shown in **Figure 5**.

As the severity of the coming storm became clear over the next few days, ERCOT issued public warnings and news releases calling for preparation and electricity conservation ([ERCOT, 2021a](#)). It also requested and was granted enforcement discretion for power plant emissions ([ERCOT, 2021b](#)), which allowed plants to run at full capacity without any parasitic losses from pollution control equipment, a standard practice during any grid emergency. Electric generators and other market participants began sending notices to customers and bringing on extra crews to manage the expected weather problems ([Gutierrez, 2021](#)).

At the same time, the Railroad Commission (RRC) revised its rule regarding natural gas delivery contracts to prioritize delivery first to residential consumers and second to electric power generators ([RRC, 2021](#)), and the PUC coordinated efforts to ensure that staff and resources were prepared for a few days of record winter demand ([PUC,](#)

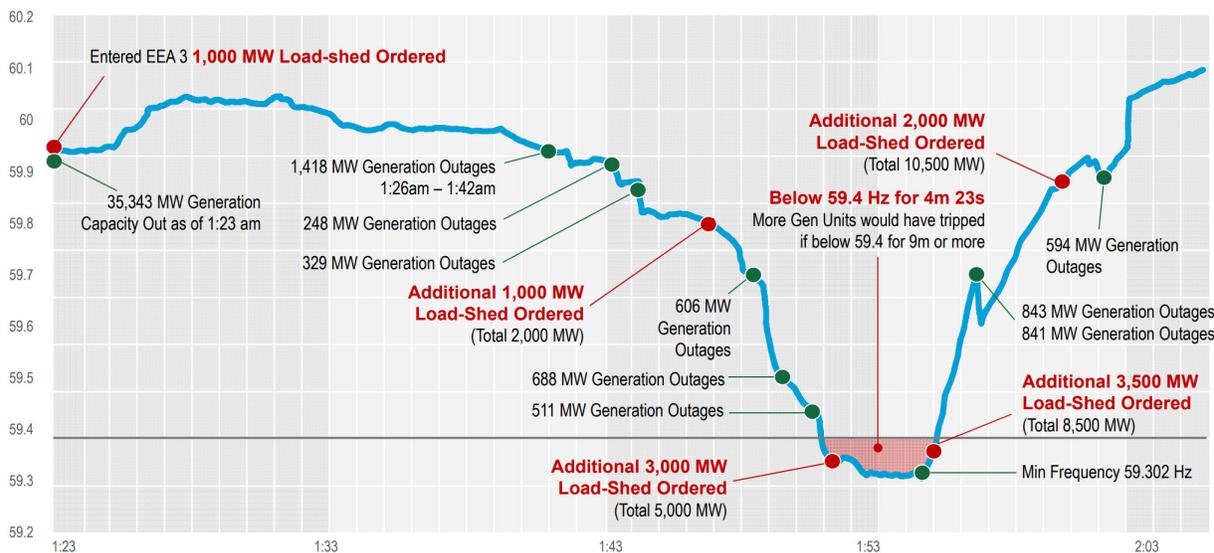
[2021b](#)). During its media availability on February 14, ERCOT ([2021c, 2:00](#)) noted that demand could exceed 70 GW during the next two days and that generator outages could be significant, likely leading to prolonged outages. However, the duration and severity of the outages took everyone by surprise.

### Grid Operations and Frequency-Related Issues at the Onset of the Storm

On the night of February 14, the ERCOT region experienced record winter demand of over 69 GW ([Magness, 2021, p. 11](#)). However, wind was producing enough electricity at the time that peak net load (demand minus wind and solar production) was below 61 GW, and the thermal fleet was able to meet demand at that time. Although demand began to decrease overnight as people went to bed and residential electricity use dropped, the passing of the storm through Central and East Texas, where a large portion of the state's gas and coal power plants are located, sent temperatures that were already near the freezing mark to well below freezing. Wind production also began to drop off in West Texas, and the cold, stable air mass settled in there. These factors led to a precipitous decline in available generation beginning around midnight on February 15 ([ERCOT, 2021d, p. 4](#)).

**Figure 6**

ERCOT System Frequency, February 15, 1:23 a.m. to 2:06 a.m.



Note. Reproduced from *Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation*, by B. Magness, Electric Reliability Council of Texas, 2021, p. 12 ([https://www.ercot.com/files/docs/2021/02/24/2.2\\_REVISIED\\_ERCOT\\_Presentation.pdf](https://www.ercot.com/files/docs/2021/02/24/2.2_REVISIED_ERCOT_Presentation.pdf)).

At 12:15 a.m. on February 15, operating reserves in ERCOT fell below 2,300 MW, and a level 1 Energy Emergency Alert (EEA1) was called, bringing emergency resources online (Magness, 2021, p. 11). At 1:07 a.m., an EEA2 was declared, and electricity supply to industrial consumers that participate in ERCOT’s demand response program was cut off. However, power plants continued to go offline in rapid succession as temperatures across most of Texas plummeted into the teens and single digits and problems with frozen equipment began to mount. At 1:23 a.m., an EEA3 was declared, and ERCOT began to order transmission companies to do what is called “firm load shed,” that is, to turn off power to customers involuntarily.

As shown in **Figure 6**, within an hour after the EEA3 was first called, an additional 6,078 MW of generation went offline, and 10,500 MW of firm load shed had been ordered. Such a rapid loss of generation during an already declared emergency was unprecedented in ERCOT’s history, and the grid frequency dropped perilously low during that time. The grid must be kept very close to 60 Hz because generators, which use rotating masses to create electricity, must be kept in perfect sync with the grid to avoid irreparable damage to their equipment. Much of the equipment in the transmission and distribution system is also designed to operate within a very narrow range

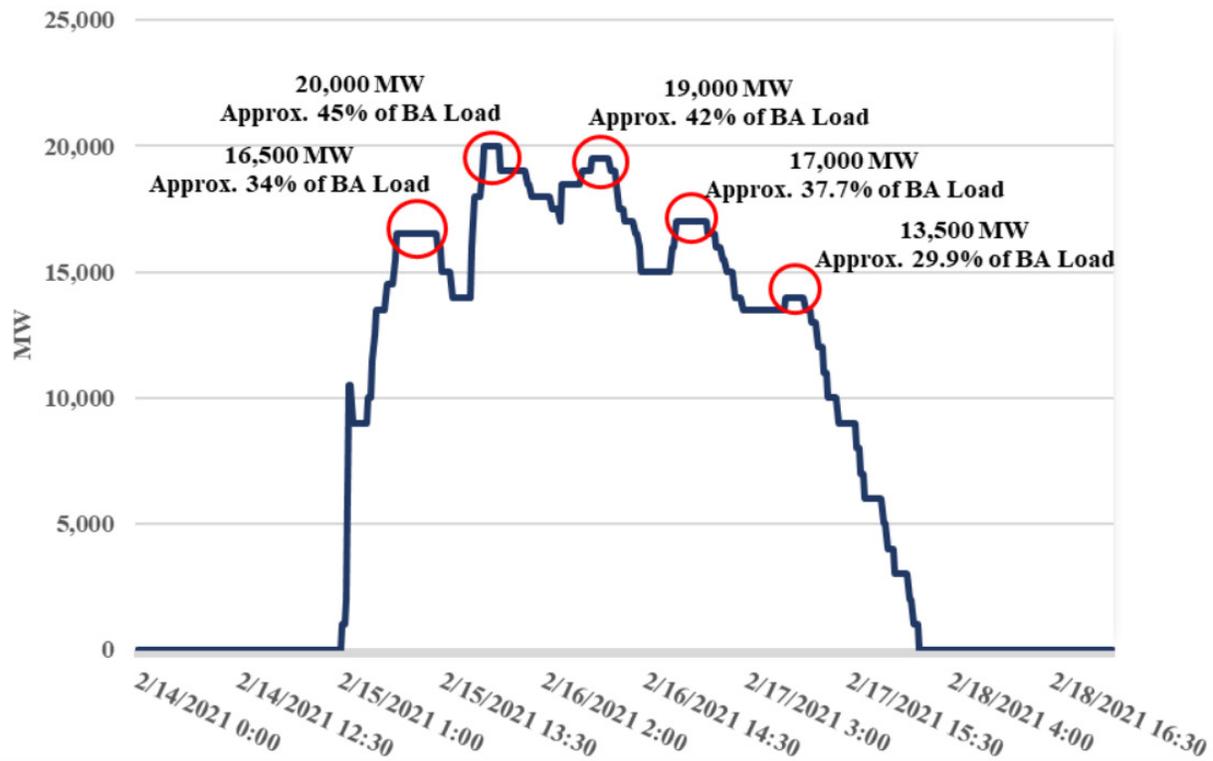
around 60 Hz. Beginning at 1:51 a.m. on February 15, the grid frequency dipped below 59.4 Hz for more than four minutes, and if the frequency had remained that low for more than nine minutes, more generators would have been forced offline. Had that happened, it is likely that the entire grid would have shut down, and the state would have been without power for weeks, unleashing a deadly catastrophe of unprecedented scale.

Fortunately, the ERCOT operations team kept the grid from collapsing, but the consequence was shedding about 16% of the demand on the system, necessitating rolling outages throughout the state while most people were asleep. Also, although the frequency was maintained above the level needed to avoid a catastrophe, several power plants reported tripping offline due to low frequency or rapid frequency fluctuations in their part of the grid (ERCOT, 2021d, p. 18–19). Unfortunately, that 10 GW of load shedding was just the beginning.

**Figure 7** (next page) shows that firm load shed reached 16.5 GW during the morning of February 15 and peaked at 20 GW that night. A combination of additional power plant failures and wind production falling from nearly 10 GW the night of February 14 to less than 1 GW the next evening made the additional load shedding necessary.

**Figure 7**

ERCOT EEA3 Firm Load Shed Ordered (MW)



Note. Reproduced from *The February 2021 Cold Weather Outages in Texas and the South Central United States*, Federal Energy Regulatory Commission, 2021, p. 153 (<https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and>).

Twenty gigawatts of load shedding was more than 25% of forecast demand across the state at that time, which meant that at least 25% of Texas consumers were without power. The proportion of residential customers affected was much higher because much of the available electricity had to be reserved for critical infrastructure like hospitals, and almost all Texas residential and commercial consumers lost power at some point during the day as the outages were rotated.

Load shedding remained at those high levels all the way through the middle of the day on February 17 before declining and ending on February 18. A primary cause of the outages was a lack of firm capacity to serve the expected demand, and that problem alone would have likely caused more than a day of load shedding, possibly reaching almost 10 GW the evening of February 15. However, the depth and duration of load shedding were made worse by disruptions to gas supplies and to weather-related problems at power plants, which will each be discussed in the next two sections.

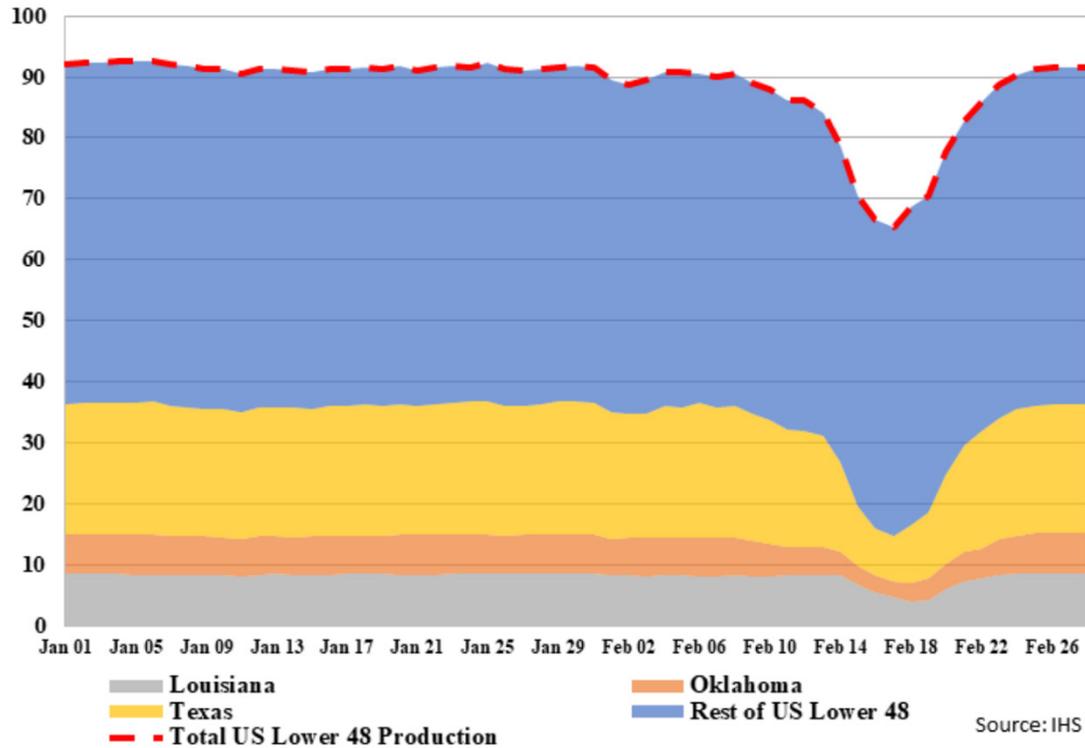
### Disruptions in Fuel Supplies

Disruptions in fuel supplies were a major cause of the long duration of the outages because they prevented many power plants from operating at full capacity even if their equipment was operating well. While some coal power plants reported disruptions to fuel supplies, those disruptions were not large in scope, roughly 2 GW, and primarily limited to February 16 and 17 (Magness, 2021, p. 19). Most of the fuel supply problems during the storm—not counting the lack of wind and sun, which will be discussed later—were related to natural gas.

As shown in **Figure 8**, natural gas production in Texas and Oklahoma declined by about 10% during the week prior to February 14 because of freezing temperatures and icing that began on February 10. Production then began dropping precipitously on the 14th as the coldest air swept through West Texas, bottoming out at less than half of average daily production on February 17. According to the final autopsy report of the Federal Energy Regulatory Commission and the North American Electric Reliability

**Figure 8**

U.S. Daily Dry Natural Gas Production, January–February 2021 (Billion Cubic Feet per Day)



Note. Reproduced from *The February 2021 Cold Weather Outages in Texas and the South Central United States*, Federal Energy Regulatory Commission and North American Reliability Corporation, 2021, p. 174 (<https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and>).

Corporation (FERC, 2021, p. 102), about half the decline in production in the region was due to freezing issues or shut-ins to prevent freezing, and the other half was due to loss of power (primarily in the ERCOT region) or a combination of problems, some related to the storm and some not related.

According to ERCOT, about 3 GW of natural gas generating capacity was offline on February 14 due to cold weather in West Texas and high demand for residential heating, which, per the RRC’s rules, is required to have priority in gas delivery contracts (RRC, 2021). Generation outages or derates due to lack of fuel jumped above 4 GW the morning of February 15, likely a direct result of the onset of power outages, and the number gradually increased until peaking at nearly 7 GW on February 17. The number then declined to less than 3 GW by the end of the week as the weather warmed and natural gas production began returning to normal levels.

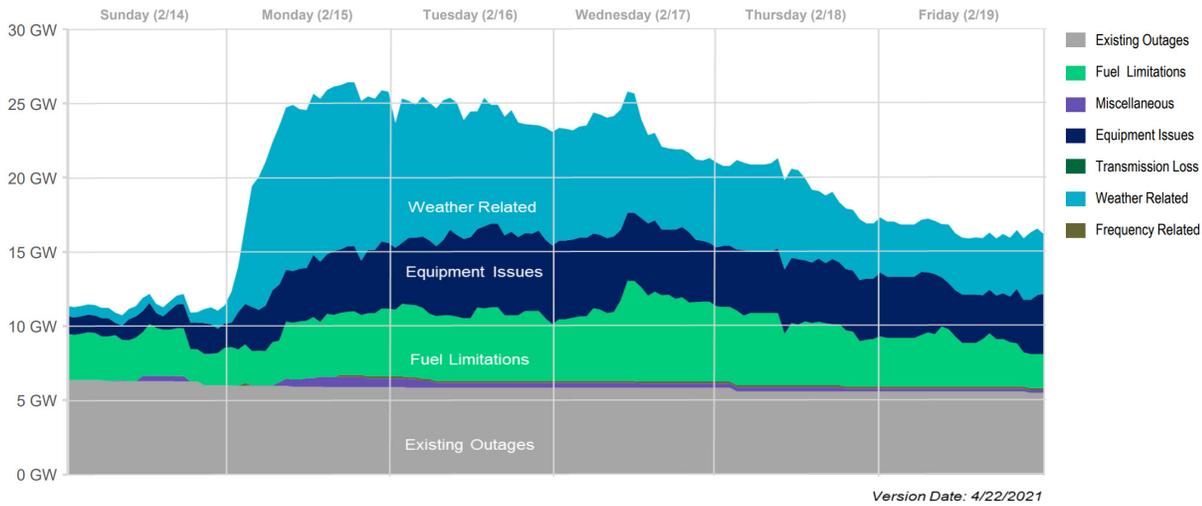
In the 1980s, the effect of fuel shortages on natural gas generators was mitigated by switching to fuel oil stored on site,

a practice that has declined in recent years due to the economic inefficiency of storing fuel for rare winter events and to environmental regulations. However, the PUC, pursuant to a statutory directive in SB 3, is developing a “firm fuel” product that will compensate generators for storing fuel on site for extreme weather events like Uri (Memorandum from Ben Haguwood, 2021, p. 3).

### Weather-Related Impacts to Electric Power Generators

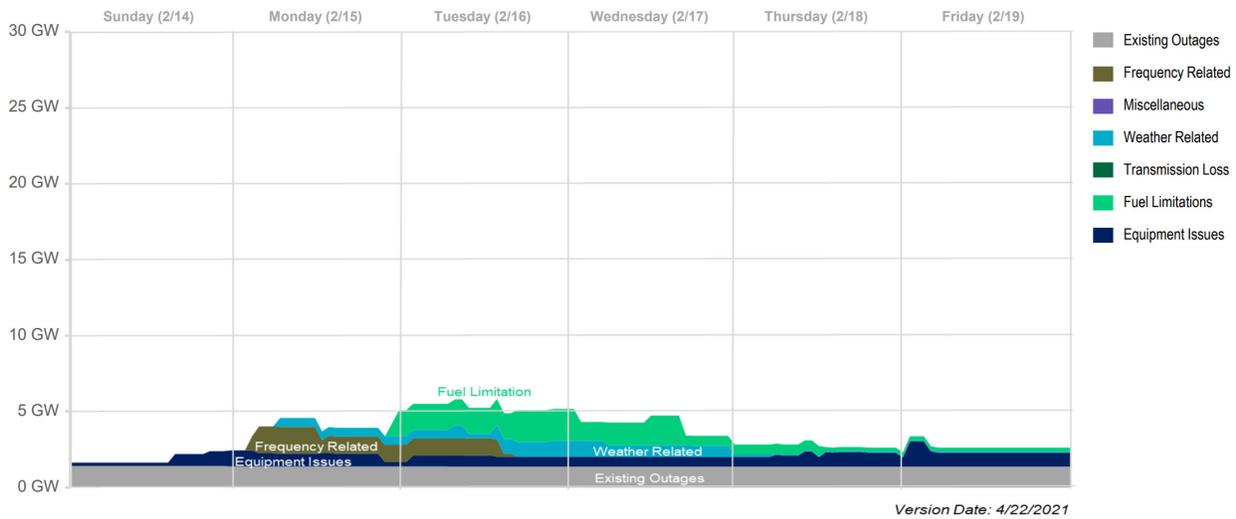
The weather-related problems with power generators during Uri can largely be traced to the fact that power generators in Texas optimize their operations for the hottest summer days and have little incentive to invest in resiliency against rare winter storms, just as power plants in northern states invest significantly in cold weather resiliency but not for extreme heat. This fact is reflected in Figure 5, which shows how the Texas fleet minimizes outages from June through September, schedules most maintenance outages in the spring and fall, and has a higher level of outages in the winter than in the summer.

**Figure 9(a)**  
 Net Generator Outages or Derates for Natural Gas Generators by Cause



Note. Reproduced from *Update to April 6, 2021 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event*, Electric Reliability Council of Texas, 2021, p. 18 ([https://www.ercot.com/files/docs/2021/04/28/ERCOT\\_Winter\\_Storm\\_Generator\\_Outages\\_By\\_Cause\\_Updated\\_Report\\_4.27.21.pdf](https://www.ercot.com/files/docs/2021/04/28/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf)).

**Figure 9(b)**  
 Net Generator Outages and Derates for Coal Generators by Cause

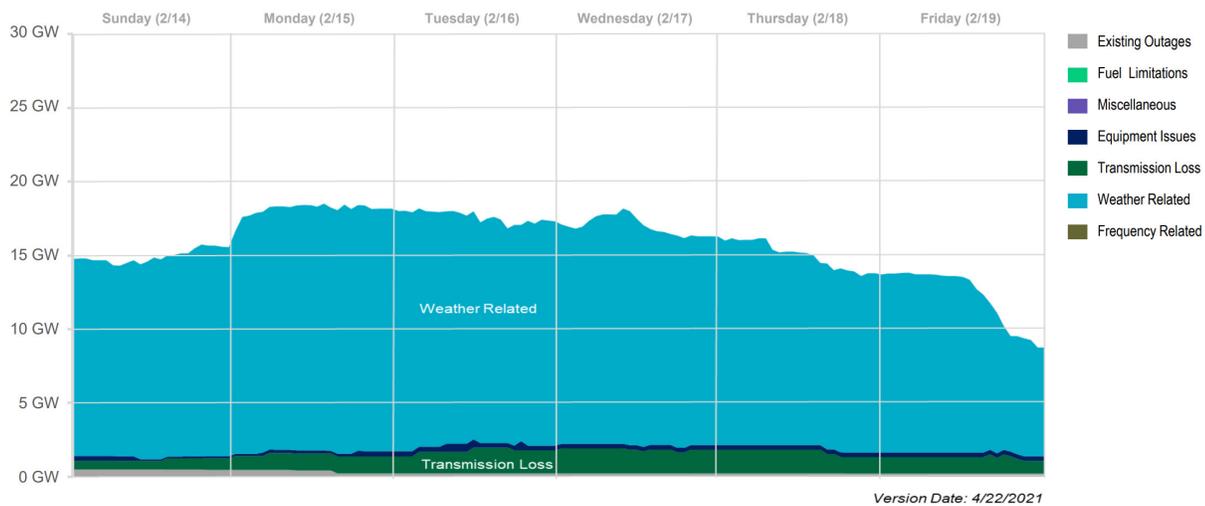


Note. Reproduced from *Update to April 6, 2021 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event*, Electric Reliability Council of Texas, 2021, p. 19 ([https://www.ercot.com/files/docs/2021/04/28/ERCOT\\_Winter\\_Storm\\_Generator\\_Outages\\_By\\_Cause\\_Updated\\_Report\\_4.27.21.pdf](https://www.ercot.com/files/docs/2021/04/28/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf)).

Figures 9(a) and (b) on the following page, show the amounts and causes of gas and coal generator outages and derates from February 14–19. Consistent with historical norms, about 13 GW of gas and coal generation was offline on February 14, just prior to the onset of the storm.

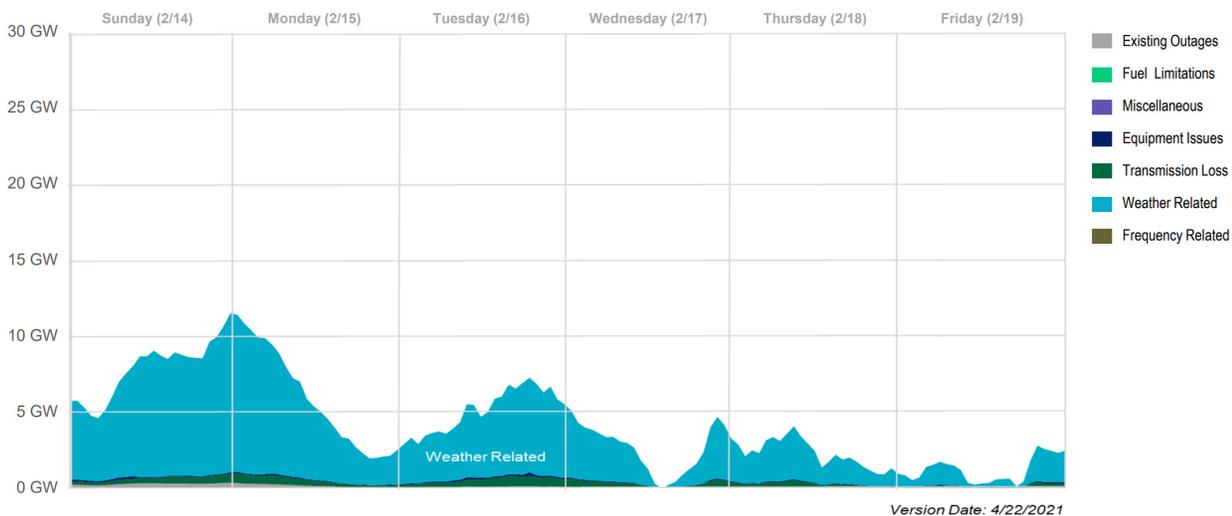
Operators were able to recall all but about 8 GW that was offline for long-term maintenance (gray areas), and about 2 GW of outages due to equipment and weather issues had already been reported. The remaining 3 GW were due to natural gas supply shortages.

**Figure 10(a)**  
 Net Generator Outages or Derates for Wind Generators by Cause Based on Installed Capacity



Note. Reproduced from *Update to April 6, 2021 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event*, Electric Reliability Council of Texas, 2021, p. 20 ([https://www.ercot.com/files/docs/2021/04/28/ERCOT\\_Winter\\_Storm\\_Generator\\_Outages\\_By\\_Cause\\_Updated\\_Report\\_4.27.21.pdf](https://www.ercot.com/files/docs/2021/04/28/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf)).

**Figure 10(b)**  
 Net Generator Outages or Derates for Wind Generators by Cause Based on Forecasted Output



Note. Reproduced from *Update to April 6, 2021 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event*, Electric Reliability Council of Texas, 2021, p. 21 ([https://www.ercot.com/files/docs/2021/04/28/ERCOT\\_Winter\\_Storm\\_Generator\\_Outages\\_By\\_Cause\\_Updated\\_Report\\_4.27.21.pdf](https://www.ercot.com/files/docs/2021/04/28/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf)).

As the cold front rolled across the state in the early morning hours of February 15, the amount of gas generation capacity reported offline due to weather-related problems rapidly increased to more than 10 GW, and other equipment problems also increased significantly. One of the two units

at the South Texas Project nuclear plant went offline later that morning due to problems with its feedwater pumps ([U.S. Nuclear Regulatory Commission, 2021](#)). Weather was a less significant problem for coal plants, with frequency-related problems and then fuel supply (potentially due to the

weather) causing most of the reported outages and derates. Thermal power plant outages and derates peaked just above 30 GW on February 17. While power plants came back online as the week went on, nearly 20 GW was still offline as of February 19, and demand reduction due to warmer weather was the main reason ERCOT was able to end firm load shedding on February 18.

Wind generation also suffered extensively from the weather, particularly from ice that coated wind turbine blades and rendered them inoperable. About half of the installed wind capacity in ERCOT was offline for the entire duration of the storm ([ERCOT, 2021d, p. 20](#)), and most of that capacity was offline prior to February 14 due to freezing precipitation that had already occurred in West and North Texas, where most of the state's wind capacity is located. Some transmission-related constraints and outages were reported, but those losses were limited to about 2 GW. Some weather-related outages of solar generators were also recorded, but those losses were limited to a few hundred megawatts ([ERCOT, 2021d, p. 23](#)).

The larger problem for wind and solar generators was the lack of wind and solar resources available throughout the storm. Solar generators do not expect to produce much electricity during such storms, especially during the winter peak demand hours around 8 a.m. and 8 p.m., but ERCOT's SARA anticipated average wind production of 7 GW during the winter peak demand hours ([ERCOT, 2020a, p. 2](#)). However, wind generation dipped below 1 GW around 8 p.m. on February 15 and around 8 a.m. on February 17 and averaged only 4.3 GW across all hours from February 15 to February 19 ([EIA, n.d.-b](#)).

Having more wind turbines online would have helped significantly on February 14 and on the morning of the 15th as the primary cold front was passing through the state, adding more than 10 GW of generation at the time rotating outages began, according to the analysis provided by ERCOT ([ERCOT, 2021d, p. 21](#)). However, during the rest of the storm, eliminating all the wind outages and derates would have only added at most 7 GW of generation on the night of February 18 and only a few GW during most of the remainder of the week—nowhere near enough to prevent widespread blackouts.

This problem highlights the fact that, while weather and fuel supply problems added to the depth and duration of the outages that Texans experienced, resource adequacy was a fundamental cause of the outages. In fact, even if the weather and fuel supply problems had been eliminated, it

is likely that the ERCOT region would have experienced up to 24 hours of outages with as much as 10 GW of load shed the night of February 15. While resource adequacy received relatively little discussion in the media and in many of the autopsies of the event, it did not escape the attention of Texas legislators (see sections 14 and 18 of SB 3) and the PUC, which has begun a detailed examination of market reforms to address resource adequacy ([Memorandum from Ben Haguewood, 2021](#)). Therefore, this issue deserves a more detailed discussion.

## The Shortage of Firm Generation During Winter Storm Uri

The two EEA1 situations in August 2019 made it clear that low wind output during peak demand periods was creating a resource adequacy problem for the ERCOT region. During that week, the EEAs did not occur on the day of highest demand but on two subsequent days ([ERCOT, 2019, p. 23](#)). However, despite the outages that occurred in February 2011, it was widely expected that Texas would see the first widespread outages due to this problem in the summer, not in the winter. Nevertheless, ERCOT's planning scenarios ([ERCOT, 2020a, p. 2](#)) demonstrate that the extreme level of demand during Uri, comparable to peak summer demand, combined with low wind and solar output, would lead to a situation where the grid was short of firm generating capacity.

One reason that winter outages are difficult to forecast is that unlike in the Texas summer, when it is consistently hot and record temperatures fall within a narrow range, winter low temperatures in Texas vary dramatically. Therefore, winter peak demand is also highly variable. ERCOT's Winter 2020/2021 SARA report shows a 43% reserve margin for average peak demand of 57,699 MW and available generating capacity of 82,513 MW ([ERCOT, 2020a, p. 2](#)). Normally, reserve margins over 15% are more than adequate, but a deeper look into the side cases provided by ERCOT (see **Table 2**) shows why these numbers do not represent the true risks to the system.

While the 57,699 MW forecast represents a median scenario for peak winter demand, ERCOT also includes an upper 10th percentile scenario (labeled "extreme demand" in **Table 2**) that is 9,509 MW higher, or 67,208 MW, just shy of the 69,222 MW record reached on February 14. Add to that higher demand scenario the normal amount of long-term maintenance and forced outages for thermal power plants (third column in the table), and the projected reserve margin shrinks to 5,892 MW, or about 10%. Prior to the outages, ERCOT's forecast peak demand for the

**Table 2**

Range of Potential Risks From ERCOT Winter 2020/2021 Seasonal Assessment of Resource Adequacy

	ERCOT Baseline Scenario	Extreme Demand	Extreme Demand + Typical Maintenance Outages	Extreme Demand + Typical Maintenance Outages + Typical Forced Outages	Extreme Demand + Typical Maintenance Outages + Typical Forced Outages + Low Wind Output	Extreme Demand + Typical Maintenance Outages + Typical Forced Outages + Low Wind Output + Extreme Forced Outages, Thermal
Winter Resources Available	86,908	82,513	82,513	86,908	86,908	86,908
Estimated Winter Peak Demand	- 57,699	- 57,699	- 57,699	- 57,699	- 57,699	- 57,699
Extreme Demand	0	- 9,509	- 9,509	- 9,509	- 9,509	- 9,509
Typical Maintenance Outages, Thermal	0	0	- 4,074	- 4,074	- 4,074	- 4,074
Typical Forced Outages, Thermal	0	0	0	-5,339	-5,339	-5,339
Low Wind Output	0	0	0	0	-5,279	-5,279
Extreme Forced Outages, Thermal	0	0	0	0	0	-4,540
Total Uses of Reserve Capacity	0	9,509	13,583	18,922	24,201	28,741
Reserve Margin, MW	24,814	15,305	11,231	5,892	613	-3,927 ▲
Reserve Margin, %	43.0%	26.5%	19.5%	10.2%	1.1%	-6.8% ▲

Note. Data from *Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021*, Electric Reliability Council of Texas, 2020 (<https://www.ercot.com/files/docs/2020/11/05/SARA-FinalWinter2020-2021.pdf>).

week was 76,819 MW ([Magness, 2021, p. 19](#)), which means that even with average thermal outages during Uri, the grid may have been short nearly 4,000 MW.

However, the problem runs much deeper than that because the hours of lowest wind output during Uri were correlated with some of the times of highest demand. Wind generation fell as low as 649 MW at 8 p.m. on February 15 and again dipped below 1 GW at 8 a.m. on the morning of the 17th ([EIA, n.d.-b](#)). At no time during the 8 a.m. or 8 p.m. peak demand hours from the 15th to the 18th did wind generation reach the 7,070 MW average level given by the SARA report.

Even adding back the lost wind output due to weather-related failures ([ERCOT, 2021d, p. 21](#)), generation would have only been around 3 GW on the night of February 15. This scenario is roughly equivalent to the scenario given in the fourth column in **Table 2**, but with 6 GW more demand, leaving the ERCOT grid still well short of having adequate generation resources. Again, this is a scenario where thermal outages are less than 10 GW, which is fewer outages than what was experienced the week prior to Uri and better than the operational performance of the thermal

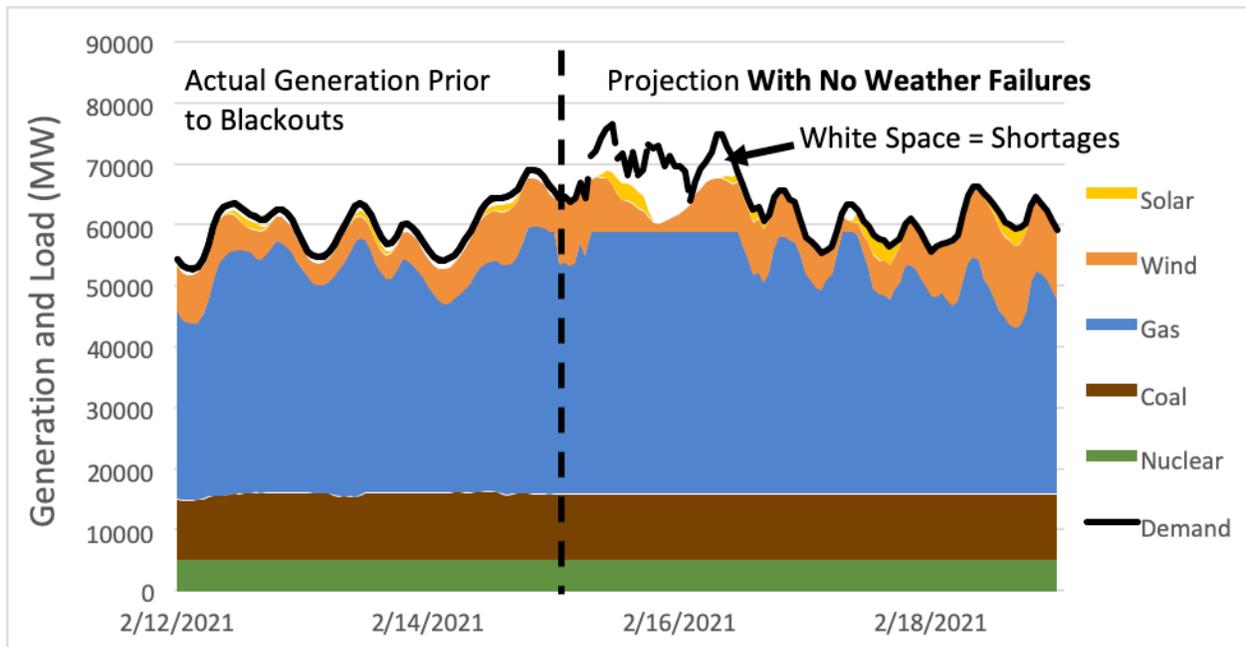
fleet during weather events that were far less severe than Uri.

In other words, outages were inevitable to some degree during Uri, even if the weather failures and gas supply problems that began on February 14 and lasted throughout the week had not been present. A simple way to show this gap between supply and demand is to project through the week of the storm using the demand forecasts before the outages started, assuming the same level of thermal fleet outages as existed on February 14 (i.e., minimal weather-related failures), and doubling the amount of wind generation that was actually realized. **Figure 11** shows that even under this idealized scenario, the ERCOT grid would still have experienced outages lasting roughly 24 hours from February 15 to February 16.

From a policy and market design standpoint, it is unreasonable to design the ERCOT grid to handle an event as rare and severe as Uri with no outages whatsoever. The cost of providing that level of insurance would require electric rate increases that a vast majority of Texans would consider unacceptable. However, looking beyond the obvious weather resiliency problems exposed by the storm, the

**Figure 11**

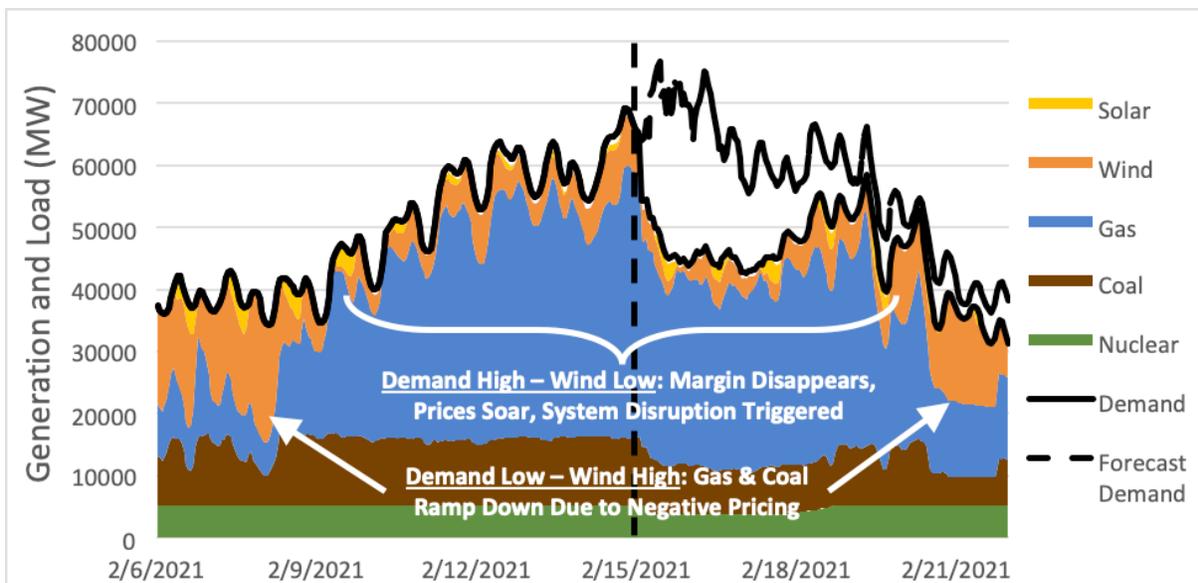
Actual Demand and Generation by Resource Type (in MW) Prior to February 15, 2021, and Forecast Demand and Generation from February 15 Onward, Assuming No Weather-Related Problems for Thermal Generators and Twice the Actual Wind Generation That Was Realized



Note. Data from *Hourly Electric Grid Monitor*, “Electric Reliability Council of Texas, Inc. (ERCOT) Electricity Overview,” U.S. Energy Information Administration, n.d. ([https://www.eia.gov/electricity/gridmonitor/dashboard/electric\\_overview/balancing\\_authority/ERCOT](https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCOT)).

**Figure 12**

Demand and Generation by Resource Type (in MW) from February 6, 2021, to February 21, 2021



Note. Data from *Hourly Electric Grid Monitor*, “Electric Reliability Council of Texas, Inc. (ERCOT) Electricity Overview,” U.S. Energy Information Administration, n.d. ([https://www.eia.gov/electricity/gridmonitor/dashboard/electric\\_overview/balancing\\_authority/ERCOT](https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCOT)).

**Table 3**

*Installed Capacity of Generation Resources in the ERCOT Region as a Percentage of the Grid-Wide Total, Proportion of Total Electricity Generation from February 9, 2021, to February 19, 2021, and Proportion of Total Electricity Generation at 8 p.m. on February 15.*

Installed Capacity		February 9–19		February 15, 8 p.m.	
Wind	28%	Wind avg	9%	Wind	1%
Solar	5%	Solar avg	1%	Solar	0%
Gas	49%	Gas avg	61%	Gas	71%
Coal	12%	Coal avg	19%	Coal	18%
Nuclear	4%	Nuclear avg	9%	Nuclear	9%

Note. Data from *Hourly Electric Grid Monitor*, “Electric Reliability Council of Texas, Inc. (ERCOT) Electricity Overview,” U.S. Energy Information Administration, n.d. ([https://www.eia.gov/electricity/gridmonitor/dashboard/electric\\_overview/balancing\\_authority/ERCOT](https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCOT)) and *Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021*, Electric Reliability Council of Texas, 2020 (<https://www.ercot.com/files/docs/2020/11/05/SARA-FinalWinter2020-2021.pdf>).

resource adequacy problems that first became apparent in 2019 are clearly growing worse. If Texas continues to rely on new wind and solar generation to meet its growing electricity demand, while at the same time shrinking its base of reliable gas and coal generation, outages will be more common in the future under far less severe weather conditions than the state experienced during Uri.

Taking a broader look at the generation resource mix both before and after Uri demonstrates the depth of the intermittency problem that Texas is facing. As shown in **Figure 12**, prior to the initial onset of cold weather on February 10, wind at times exceeded half of the generation mix in ERCOT, and gas and coal plants were ramping down to accommodate the influx of excess wind generation. Real-time prices in the wholesale market were near zero the morning of February 8 and generally near or below \$20/MWh until February 9 ([ERCOT, n.d.-b](#)).

Wind production then dropped after the first cold front moved through the state, coinciding with the drop in temperatures as a cold high-pressure system set in. It is common for high-pressure systems during the summer and the winter to reduce wind speeds, because those air masses are more stable, and to create extreme high or low temperatures, because low winds lead to less mixing in the atmosphere. Therefore, low wind generation is frequently correlated with high electricity demand, exacerbating the degree to which gas and coal plants need to ramp up or down compared to a system where demand is the only variable factor.

This effect was evident during Uri, as wind generation did not exceed 10 GW, or about a third of total installed wind capacity in the ERCOT region, until temperatures

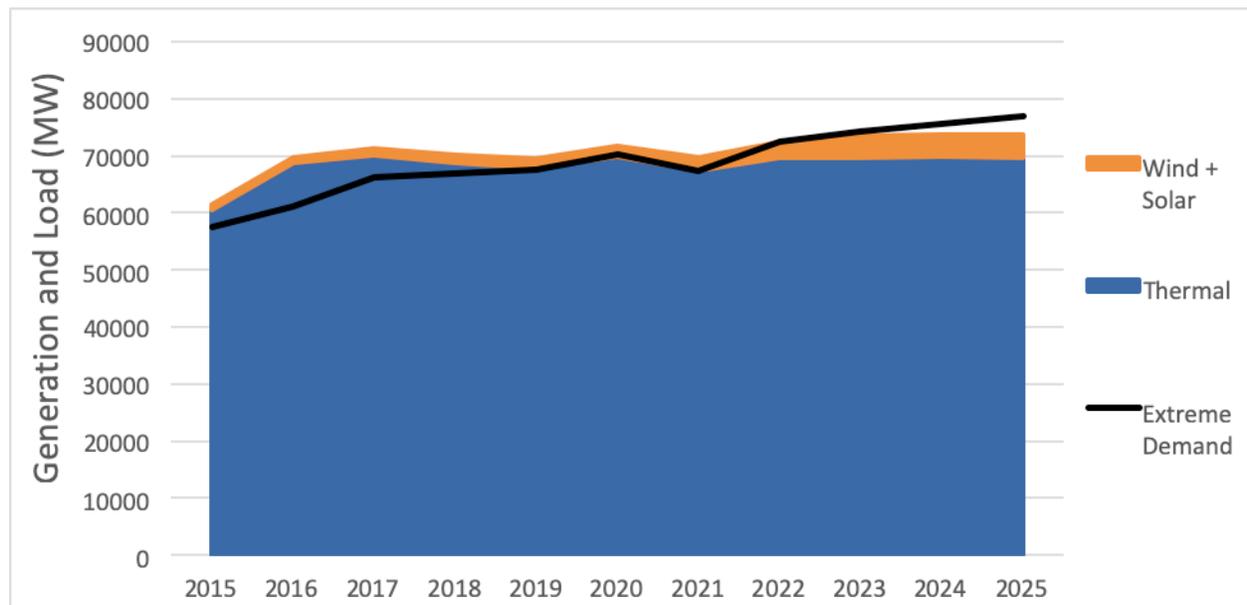
began warming again on February 19, at which time wind generation returned to pre-storm levels ([EIA, n.d.-b](#)). The volatility of wind resources was reflected in real-time market prices. Even prior to the onset of outages, the combination of high demand and low wind production drove average real-time prices above \$1,000/MWh for most of February 13 and 14, before being fixed at the market wide cap of \$9,000/MWh from February 15 to February 19 ([ERCOT, n.d.-b](#)). Real-time prices then went briefly negative on February 19 as demand dropped and wind production recovered, and negative prices were present multiple times over the course of the next week.

The average capacity factor of wind generation from February 9 to February 19 was only 15%, and solar was only 11% ([EIA, n.d.-b](#)). Over that period, wind and solar provided 10% of the electricity generated in the ERCOT region, even though they made up 33% of installed capacity in the region at the time (see **Table 3**). At the nadir of combined wind and solar production on the night of February 15, those resources produced less than 2% of the total generation in the region. Coal, gas, and nuclear, on the other hand, provided 90% of the state’s electricity throughout the storm, and despite the raft of outages, the thermal fleet exceeded its average February capacity factor from February 9 to February 19.

As noted above, the reduced performance of wind and solar during Winter Storm Uri is primarily a resource adequacy problem resulting from typical winter weather patterns that combine extreme low temperatures with low wind and solar output. Comparisons of how many wind and solar generators were offline versus thermal generators during Uri miss the point. The policy implication of this data is that the ERCOT market design needs to ensure that adequate resources are available when high demand correlates with

**Figure 13**

*Projected Winter Demand and Generation for the ERCOT Region Assuming High 10th Percentile Peak Demand, Low 5th Percentile Wind and Solar Output, and Average Thermal Power Plant Outages*



Note. Data from *Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2022–2031*, Electric Reliability Council of Texas, 2021 ([https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport\\_December2021.pdf](https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.pdf)) and *Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021*, Electric Reliability Council of Texas, 2020 (<https://www.ercot.com/files/docs/2020/11/05/SARA-FinalWinter2020-2021.pdf>).

low wind and solar output, which can not only happen during summer afternoons but also during winter storms.

Unfortunately, ERCOT's December 2021 *Report on the Capacity, Demand, and Reserves (CDR)* (ERCOT, 2021h, p. 28) is not projecting significant growth of thermal, dispatchable resources to meet increasing winter demand, leading to a greater likelihood of shortages when temperatures are not as cold as they were during Uri. Applying the upper 10th percentile adjustment factor to the peak demand forecasts in the CDR report, which was still several GW short of the forecast demand during Uri, **Figure 13** shows that a combination of high demand, normal thermal outages, and low wind and solar output will result in shortages as soon as 2024. The actions of the Texas Legislature and the Public Utility Commission of Texas to address both the problems that were specific to Winter Storm Uri and the broader resource adequacy problem facing the ERCOT region will be summarized in the next two sections.

### **Actions of the Texas Legislature Following Winter Storm Uri**

A remarkable aspect of Winter Storm Uri was that it occurred roughly three weeks before the bill filing deadline

for the 87th regular session of the Texas Legislature. As a result, several dozen bills were filed related to the storm or to electric grid reforms in general. This analysis will only cover bills that passed and were signed into law and will focus on the most consequential market reforms. In general, the legislative changes fall into four categories: (1) reform of state agency leadership structures and emergency management practices, (2) consumer protection, (3) securitization of debts from the storm, and (4) weather resiliency and electric market reform.

### **Reform of State Agency Leadership Structures and Emergency Management Practices (SB 2, SB 2154, SB 3 Sec. 34; SB 3 Secs. 3, 4, 17, 24, 25, 26, 33, 36, 37)**

The most consequential governance changes following the storm were the resignation of all three PUC commissioners and six out-of-state ERCOT board members, and legislation was passed to reform the leadership structure of each entity (Pollock & Mulcahy, 2021; Douglas & Ferman, 2021). SB 2 was the most significant of these bills. It reduced the number of ERCOT board members from 16 to 11, required that all board members and the PUC chair be Texas residents, and forbade market participants from being on the board (SB 2, 2021). The statute

**Table 4**

Legislation Passed by the 87th Texas Legislature to Address the Problems Exposed by Winter Storm Uri

Category	Legislation	Description
Agency leadership	SB 2	Reform of ERCOT leadership structure
	SB 3 Secs. 34, 35	Annual review of the statutes, rules, protocols, and bylaws for PUC and ERCOT leadership
	SB 2154	Reform of PUC leadership structure
Emergency management	SB 3 Secs. 4, 17, 37	Designation of critical natural gas facilities and creation of the Texas Electricity Supply Chain Security and Mapping Committee
	SB 3 Sec. 24	Requires the PUC to submit biannual emergency preparedness reports
	SB 3 Sec. 25	Requires the RRC to submit biannual emergency preparedness reports for critical natural gas infrastructure
	SB 3 Secs. 26, 36	Requires water utilities to ensure minimum pressure levels during power outages
	SB 3 Sec. 33	Establishes the State Energy Plan Advisory Committee
	SB 3 Sec. 3	Establishes the Texas Energy Reliability Council
Consumer protection	SB 3 Secs. 1, 2	Mandates the creation of a statewide power outage alert system
	SB 3 Sec. 18	Mandates the creation of a new wholesale market emergency pricing program
	HB 16	Prohibits wholesale-indexed electric plans for residential or small commercial customers
	SB 3 Secs. 8, 9, 10, 11	Reform of load shedding procedures for critical residential and industrial consumers
	SB 3 Sec. 16	Designation of critical natural gas facilities and new procedures for load shedding
Securitization	HB 4492	Securitization of debts for retail electric providers and financing of uplift charges
	SB 1580	Securitization of debts for electric cooperatives
	HB 1520	Securitization of weatherization costs for non-ERCOT electric utilities
	HB 1510	Securitization of debts for gas utilities
Weatherization	SB 3 Secs. 5, 6, 21, 22, 38	Weatherization of natural gas facilities
	SB 3 Secs. 7, 13, 16, 39	Weatherization of electrical generation
	SB 3 Secs. 28, 29, 31, 32	Weatherization of certain water utility systems
Market reform	SB 3 Sec. 18	Wholesale market reform, reliability standards, and weather resiliency requirements
	SB 3 Sec. 14, 35	Ancillary services market reform
	SB 1281	Transmission planning and approval reform

Note. See the *Texas Legislature Online* (<https://capitol.texas.gov>) for more information about the legislation cited in this table.

mandates that 8 of the 11 board members be selected by a committee, which comprises three members appointed by the governor, lieutenant governor, and speaker of the House. SB 2154 altered the leadership structure of the PUC by changing the number of commissioners from 3 to 5 and requiring that all commissioners be Texas residents ([SB 2154, 2021](#)). Section 34 of SB 3 requires the PUC and ERCOT to annually review the statutes, rules, protocols, and bylaws that apply to conflicts of interest for commissioners and for ERCOT board members ([SB 3, 2021, pp. 47–48](#)).

Several sections of SB 3 address coordination and emergency preparedness for the PUC, the RRC, and the Texas Commission on Environmental Quality (TCEQ). Section 4 directs the PUC and RRC to “establish a process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical customers or critical gas suppliers during energy emergencies,” ([SB3, 2021](#)) with the goal of avoiding loss of power to those critical facilities during load shedding events. In parallel, Section 17 mandates the creation of the Texas Electricity Supply Chain Security and Mapping Committee, which is charged with identifying the critical

infrastructure in the state's electricity supply chain, establishing best practices for preparing those facilities for extreme weather, and ensuring that electricity supply to those facilities is prioritized during load shedding events. Section 37 requires the first map to be created by September 1, 2022.

Section 24 requires the PUC to submit emergency preparedness reports to the Legislature every even-numbered year, with the same structure as the report created after the load shedding event in February 2011. Section 25 mandates that the RRC prepare a similar weather emergency preparedness report for natural gas infrastructure included on the electricity chain supply map and to submit the report to the lieutenant governor, speaker of the House, and members of the Legislature no later than September 30 of each even-numbered year. Sections 26 and 36 mandate that water utilities submit emergency preparedness plans to the TCEQ by March 1, 2022.

SB 3 also created two new advisory bodies. Section 33 establishes the State Energy Plan Advisory Committee, composed of 12 members divided evenly among nominees from the governor, lieutenant governor, and speaker of the House. The committee is tasked with evaluating “barriers in the electricity and natural gas markets that prevent sound economic decisions” and “methods to improve the reliability, stability, and affordability of electric service.” It must submit the plan to the Legislature no later than September 1, 2022. Section 3 creates the Texas Energy Reliability Council, which is charged with “ensur[ing] that the energy and electric industries ... meet high priority human needs” and with improving the coordination among those industries. The council is required to submit a report to the Legislature in every even-numbered year on the reliability and stability of the electricity supply chain.

### **Consumer Protection** (*HB 16; SB 3 Secs. 1, 2, 8, 9, 10, 11, 16, 18, 35*)

Many parts of SB 3 are designed to improve public communication regarding weather and electric grid emergencies, to protect consumers from price spikes during emergencies, and to ensure critical services are maintained.

Many Texans were surprised by the severity of the storm and complained that they had no warning that electricity outages would happen, despite the fact that ERCOT knew at least a week in advance that outages were very likely. Sections 1 and 2 of SB 3 address the communication issue by mandating the creation of a power outage alert system, similar to an amber or silver alert. The Department of

Public Safety will serve as the statewide coordinator, with support and input from the Department of Transportation, the Division of Emergency Management (TDEM), and the PUC. Section 2 also calls on TDEM to create winter storm preparedness recommendations for state agencies and to develop public education materials for how to prepare disaster kits.

Section 18 requires the PUC to create a new emergency pricing program for the wholesale market, which will take effect if the high system-wide offer cap (HCAP), that is, the maximum wholesale price for electricity, has been in effect for 12 hours over a 24-hour period. Section 35 set a deadline of December 31, 2021, to complete the first review of the system-wide offer caps, and the PUC established a new HCAP on December 2, 2021 ([PUC, 2021c](#)). Under the statute, the low system-wide offer cap (LCAP) may not exceed the HCAP, and the PUC opted to fix the LCAP at \$2,000/MWh and lower the HCAP from \$9,000/MWh to \$5,000/MWh ([p. 18](#)). The program must still allow generators to be reimbursed for reasonable, verifiable operating costs that exceed the emergency cap. These reforms are designed to prevent the recurrence of the situation during Winter Storm Uri when the PUC set prices at the HCAP for more than four days.

HB 16 prohibits the sale of wholesale-indexed electric plans for residential or small commercial customers and states that all large commercial and industrial consumers must sign an acknowledgment of fluctuation risk ([HB 16, 2021](#)). The goal of the legislation is to eliminate the situation during Winter Storm Uri in which wholesale energy costs were passed directly to consumers while prices were at the HCAP and only allow more sophisticated consumers to access such products. The bill also enhances the notice requirements for price increases upon renewal for fixed contract customers.

Sections 8, 9, 10, and 11 of SB 3 address the need to improve the load shedding procedures that apply during emergencies. Section 8 designates critical care residential consumers and critical load industrial consumers, who need to be more carefully tracked and given priority during load shedding events. Critical residential consumers are consumers who are dependent on an electric-powered medical device to sustain them, and critical industrial consumers are consumers for whom suspension of electric service would create a dangerous or life-threatening condition on their premises. Sections 9, 10, and 11 require load shedding procedures to be communicated to customers of REPs, MOUs, and coops.

Section 16 requires the RRC to adopt rules to designate critical natural gas facilities and to prioritize them during load shedding events to prevent them from losing power. Electric utilities are still given discretion as to the order of priority among facilities that are designated critical, but those facilities are required to be last in the order of load shedding overall. This section also requires the PUC to adopt a system for load shedding among all electric coops, MOUs, and TDUs based on historical seasonal peak demand. Each entity must identify customers that are willing to shed load voluntarily and submit a plan to the PUC and ERCOT for prioritizing load shed. Also, the PUC and ERCOT are required to perform at least one summer and one winter load shedding exercise each year.

### **Securitization of Debts for Retail Electric Providers, Electric Cooperatives, Non-ERCOT Electric Utilities, and Gas Utilities** (*HB 4492, SB 1580, HB 1510, HB 1520*)

Following the initiation of outages on February 15, prices in the real-time market first went to the HCAP of \$9,000/MWh but then dropped as low as \$1,200/MWh. This was contrary to the intent of the scarcity pricing mechanism, which was for the HCAP to be the set price as long as firm load was being shed. Therefore, the PUC issued an order fixing prices at the HCAP and suspending the use of the LCAP for the duration of the time during which EEA3 conditions were in place and firm load was being shed ([PUC, 2021,d](#)). This order was issued to ensure that every available generator in the ERCOT market had sufficient financial incentive to remain online, especially in light of spot prices for natural gas that were at times more than 100 times above their long-term average.

This decision caused significant controversy, especially when the HCAP remained in place until ERCOT declared EEA3 to be over, which occurred at 9 a.m. on February 19, 33 hours after firm load shedding ended at midnight on February 18 ([Magness, 2021](#)). As a result, load serving entities paid several billion dollars more to generators than what would have been the case had prices not been fixed to the cap. Two bills were introduced in the Senate, SB 2142 and SB 2227, that attempted to reverse this decision and enable short paying entities to recoup their debts from generators ([SB 2142, 2021](#); [SB 2227, 2021](#)). SB 2142 was stalled in the Texas House State Affairs Committee, and SB 2227 did not pass the Texas Senate Business and Commerce Committee.

The arguments for and against reversing this pricing decision are too extensive to be covered here but are mostly

covered in the testimony of witnesses in hearings before the Texas Senate Jurisprudence Committee on March 11, 2021 ([Texas Senate, 2021b](#)), the Texas Senate Business and Commerce Committee on May 4, 2021 ([Texas Senate, 2021c](#)), and the Texas House State Affairs Committee on March 16, 2021 ([Texas House of Representatives, 2021](#)). However, the failure of the repricing bills and other attempts to reverse the PUC's pricing decisions demonstrate that the consensus among the Legislature and the PUC commissioners is that the decisions were legally justifiable and that an attempt to reverse them would likely cause far more problems than it would solve.

Instead, the Legislature chose to create a mechanism for securitizing the default balances of market participants, allowing the balances to be paid off over 30 years at a much lower interest rate than what would normally be possible for market participants on their own. This will be accomplished through a securitization corporation, which will issue bonds to cover the amounts owed to ERCOT and be repaid by the defaulting entities. Securitization is a well-known method for debt repayment that has been applied to previous natural disasters and to cost recovery of stranded assets following the period of deregulation two decades ago.

Different pieces of legislation were enacted to cover cooperatives, non-coop market participants, and non-ERCOT entities. SB 1580 covers cooperatives, a couple of whom accounted for the majority of the nearly \$3 billion in default balances from the storm ([SB 1580, 2021](#); [Moody's, 2021](#)). HB 4492 enables the financing of short pay amounts for non-coop market participants, capping the total amount of default balances to be financed at \$800 million ([HB 4492, 2021](#)). That legislation also allocates \$2.1 billion to finance the "uplift" amounts related to the reliability deployment price adder and exceptional ancillary service costs from February 12, 2021, to February 20, 2021. Finally, HB 1510 allows non-ERCOT utilities to securitize not just system restoration and repair costs, which was allowed under existing statute, but also costs for investing in weatherization and fuel resiliency to better prepare for future storms ([HB 1510, 2021](#)).

HB 1520 expands the authority of the Texas Public Finance Authority to "provide a method of financing for customer rate relief bonds authorized by the Railroad Commission of Texas" ([HB 1520, 2021](#)), the purpose of which is to finance extraordinary costs for gas utilities from the storm, during which spot prices for gas increased more than a hundred-fold ([Enverus, 2021, p. 24](#)). The RRC issued a financing

order for \$3.4 billion in bonds on February 8, 2022, which will allow eight gas utilities to pay off their debts over a period of up to 30 years and prevent those costs from having to be financed by each entity individually and assessed in a single monthly billing to their customers.

### **Weather Resiliency and Electric Market Reform** (*SB 3 Secs. 5, 6, 7, 13, 16, 21, 22, 26, 27, 28, 29, 38, 39; SB 1281; SB 3 Secs. 14, 18*)

Weatherization of infrastructure, from power plants to gas supply systems, was a dominant topic of conversation immediately following Winter Storm Uri. SB 3 contains provisions to improve the weather resiliency of electric generation, critical natural gas infrastructure, and water supply systems.

Section 5 establishes weatherization requirements for natural gas supply facilities—all the way from the wellhead to the power plants—that are included on the electricity supply chain map (see SB 3, Section 17) and are deemed critical by the RRC. The statute does not list any specific requirements except to say that the facilities should be able to operate without interruption during a weather emergency and must be inspected and remediated if they fail to do so. Section 6 authorizes a penalty of up to \$1 million for each violation of the rules, although only violations of the highest classification are eligible for penalties above \$5,000. Section 21 creates specific requirements for gas pipeline operators, and Section 22 enacts similar penalties as Section 6. Finally, Section 38 requires the RRC to implement these rules no later than six months after the mapping committee completes its work, which must occur by September 1, 2022.

Section 13 establishes weatherization requirements for electric generation, and Section 16 for transmission and distribution facilities, while requiring ERCOT to inspect those facilities. Section 7 authorizes a penalty of up to \$1 million per violation per day for failure to comply with the weatherization mandates. Section 39 requires the PUC to adopt the rules necessary to implement these provisions within six months of the effective date of SB 3, which was May 30, 2021, and the commission adopted interim rules on October 21, 2021 ([PUC, 2021e](#)). Phase 2 of the rulemaking process, which does not have a defined completion date yet, will lead to a permanent set of rules.

Finally, Sections 26 and 28 amend the water code to strengthen the weather preparedness requirements for water utilities statewide and require that they demonstrate their ability to operate and ensure water delivery to their

wholesale customers during emergencies. Previously, only the water utilities in the Houston metropolitan area counties were subject to these statutory requirements. Section 26 adds another requirement for utilities not in the Houston area that they ensure the operation of their water systems at minimum pressure levels during a power outage lasting more than 24 hours.

While weatherization is an important part of ensuring the tragedy of Winter Storm Uri does not happen again, these mandates do not mean anything if power plants and fuel suppliers are not deriving the revenue needed to pay for upgrades. As noted in the report from the American Society of Civil Engineers,

revenue insufficiency from ERCOT’s energy-only market model, influenced by federal and state subsidization of intermittent resources, fails to adequately pay for reliable dispatchable generation, and ... *these market model deficiencies are the leading contributor to making the ERCOT system less reliable* [emphasis added]. ([ASCE 2022, p. 5](#))

This is the critical problem facing the Texas grid, and reforms to the ERCOT wholesale electric market were a key part of the discussion over SB 3.

Two sections of SB 3 ([2021](#)) specifically address wholesale market reforms. First is Section 14, which deals with changes to ancillary services. The statute maintains the previous definition of ancillary services, namely, “services necessary to facilitate the transmission of electric energy including load following, standby power, backup power, reactive power, and any other services as the commission may determine by rule.” However, it requires the PUC to determine whether additional services are needed to ensure reliability and to “modify the design, procurement, and cost allocation of ancillary services for the region in a manner consistent with cost-causation principles and on a nondiscriminatory basis.” Currently, the cost of ancillary services is allocated exclusively to loads in ERCOT and not to generators. Therefore, this language could represent a significant change in how ancillary services are procured, depending on how the PUC applies the statute.

Second is Section 18, which requires the PUC to set new reliability standards and to procure ancillary or reliability services in such a manner as “to prevent prolonged rotating outages due to net load variability” ([SB 3, 2021](#)). While the Legislature declined to define a specific reliability standard, the legislative intent was clear that the PUC needed

to undergo a major reform of the wholesale market to put a greater emphasis on reliability and to incentivize the development of dispatchable power plants that can perform well in both extreme heat and extreme cold conditions. The statute also specifically requires the development of a firm fuel program to ensure that generators providing reliability services can guarantee their fuel supply during winter storms. The PUC's actions following from Sections 14 and 18 of SB 3 will be discussed in detail in the next section.

Another important area of reform is the planning, siting, and cost allocation of new transmission lines. As noted above, ratepayers pay for interconnection and transmission costs based on their share of electricity consumption (load ratio share basis) through the TCOS fee. The general idea is that having ratepayers bear these costs will help attract new generation to the market, like a city paying for a road to a new manufacturing facility. A problem arises when some types of new generation, like wind and solar, are more dispersed and farther from load centers, requiring more interconnection and transmission costs. This creates an implicit subsidy and market advantage for those resources and drives up costs to ratepayers. According to ERCOT, annual transmission expenses paid by ratepayers in the ERCOT market increased from about \$1.6 billion annually in 2011 to \$3.6 billion in 2020, driven primarily by the buildout of the CREZ lines ([ERCOT, 2020b, p. 8](#)).

Two bills were introduced during the legislative session to address this problem. SB 1282 would have required new generators to pay for any interconnection costs beyond a certain allowance ([SB 1282, 2021](#)). Since the vast majority of new generation in the ERCOT interconnection queue is wind and solar, the measure would have impacted those resources significantly. While it passed the Senate, it faced stiff lobbying resistance and died on the House floor. SB 1281, which did become law, modifies the requirements for the PUC to approve transmission projects by requiring a customer-focused economic test, that is, proof that the transmission project will reduce congestion and lower costs for consumers ([SB 1281, 2021](#)). This test replaces the producer-cost test adopted by the PUC in 2012, which only considered whether a transmission line would reduce ERCOT-wide production cost savings, a method that inherently favors building transmission for wind and solar generation. The bill also requires a biennial assessment of the ERCOT grid's reliability in extreme weather conditions, factoring in different levels of thermal and renewable generation availability, and recommends transmission projects that increase reliability.

Immediately following the end of the legislative session, the ERCOT grid faced tight conditions due to an early summer heatwave combined with low wind output and a high number of generation outages, prompting ERCOT to issue a conservation alert from June 14 to June 18 ([ERCOT, 2021f, p. 2](#)). The public outcry following the event prompted Gov. Abbott to write a public letter directing the PUC to focus on four specific reforms during their implementation of SB 3 ([Letter from Governor Abbott, 2021](#)). The four directives are worth repeating here, as they are each critical elements of the market reform process.

- Streamline incentives within the ERCOT market to foster the development and maintenance of adequate and reliable sources of power, like natural gas, coal, and nuclear power.
- Allocate reliability costs to generation resources that cannot guarantee their own availability, such as wind or solar power.
- Instruct ERCOT to establish a maintenance schedule for natural gas, coal, nuclear, and other non-renewable electricity generators to ensure there is always an adequate supply of power to the grid to maintain reliable service for all Texans.
- Order ERCOT to accelerate the development of transmission projects that increase connectivity between existing or new dispatchable generation plants and areas of need. ([pp. 1–2](#))

This letter, combined with a hearing before the Texas Senate Business and Commerce Committee on July 13, set the stage for the redesign of the wholesale market currently being undertaken by the PUC. The final section of this paper will outline the progress the PUC has made so far and what remains to be done.

### **Actions of the Public Utility Commission of Texas in Response to Senate Bill 3**

The regulatory actions of state agencies in response to the legislation in the previous section are numerous, but the PUC's effort to reconsider all aspects of the ERCOT wholesale market design is by far the most ambitious. The changes being studied and implemented represent the most significant changes to that market since the period of deregulation in the early 2000s. Building on both the directives for market reform in SB 3 and the letter from Gov. Abbott on July 6, 2021, the PUC convened a series of work sessions from August to December 2021 to review

proposals for reforms to the wholesale electric market ([Memorandum from Chairman Peter M. Lake, 2021a](#)).

These work sessions and the results of the process are a clear statement that the PUC commissioners recognize, as stressed in this paper, the urgent need to address the growing resource adequacy problem in the ERCOT market. This opinion is not shared by all ERCOT market participants, particularly wind and solar generators who are thriving under the existing market design and who advocated against significant market reforms during the work sessions. Nevertheless, the PUC and ERCOT are already implementing several reforms and engaging in further study of longer-term market redesign options ([PUC, 2022](#)). This section will detail the outcomes of those work sessions and other important actions the PUC has undertaken in response to SB 3.

### Rulemakings to Address Weather Resiliency

The most immediate actions the PUC is taking are developing new rules for winterizing power plants and creating a “firm fuel” product that will provide incentives for power plants to store fuel on site, develop dual fuel capability, and secure guaranteed fuel delivery. Each of these processes is operating in a phased manner, with some initial changes to improve preparedness for 2022 and 2023 and more complete and permanent reforms to take effect after that.

In order to ensure preliminary weatherization standards were in place before the 2021–2022 winter, the PUC implemented a new rule §25.55 in Docket No. 51840 to require generators and transmission service providers to “fix any known, acute issues that arose from winter weather conditions during the 2020–2021 winter weather season” and to implement recommendations following the 2011 winter storm ([PUC 2021d, p. 1](#)). Each relevant entity was required to complete these winter preparation measures and submit a winter weather readiness report by December 1, 2021. ERCOT and the Office of the Texas State Climatologist submitted a historical weather study to the PUC on December 15, 2021 ([Rickerson, 2021](#)), and the PUC is planning to complete a permanent, year-round set of reliability standards based on the findings in that study ([PUC 2021d, p. 2](#)).

The other significant action to improve winter weather resiliency that was mandated by SB 3 is the development of a firm fuel product to incentivize more fuel storage and dual fuel capability for long-duration storms like Winter Storm Uri. Commissioners Cobos and McAdams submitted memos on January 26, 2021, outlining their

preferences for the initial phase of the program to be ready for the winter of 2022/2023, with the first RFPs submitted by August 2022 ([Garcia, 2022](#)). The general thrust of both proposals is to structure the program like the Emergency Response Service (ERS), with a cost cap and cost allocation on a load ratio share basis. The first phase of the program would focus on dual fuel capability—using diesel as a backup fuel—and onsite natural gas storage with a duration of at least two days. A later phase would consider offsite gas storage and firm transport arrangements.

At the request of the commissioners, ERCOT identified 11 power plants that currently have operable dual fuel capability, representing more than 4 GW of capacity for at least 72 hours ([Letter from Dan Woodfin, 2021](#)). Three power plants have roughly 800 MW of natural gas storage capacity for at least 72 hours of operation. ERCOT also found that no other ISO has an explicit firm fuel program like what is being contemplated, although the New England ISO is developing a program for the winter of 2023/2024 ([Letter from Kenan Ögelman, 2022](#)). Secure fuel supply is generally an inherent component of the broader reliability standards that other ISOs employ, and most other ISOs are not as dependent on natural gas as Texas is.

It remains to be seen if the PUC will enable coal and nuclear generators to participate in the program, given that those generators inherently operate with months of onsite fuel storage. The memos from Commissioners Cobos and McAdams consider only natural gas for the first phase of the program, and the commissioners reiterated that intention at their open meeting on January 27, 2022. The general tenor of the conversation indicated that the commissioners might decide to leave coal and nuclear out of the second phase as well, citing concerns about the cost of the program if it was made too broad and the absence of an immediate need to incentivize more coal and nuclear fuel storage since those plants already store fuel onsite. However, the counter concern is that leaving coal and nuclear out of the program might further reduce their competitiveness in the market and accelerate retirements of coal plants.

### Phase 1 Wholesale Market Reforms

As part of the PUC’s blueprint for market reform ([Memorandum from Ben Haguewood, 2021](#)), which the commissioners approved on December 16, 2021, the following market reforms—deemed to be Phase 1 of the market redesign process—are to be implemented as soon as practicable.

### ***Operating Reserve Demand Curve (ORDC) Pricing Changes***

As noted above, the PUC set the HCAP to \$5,000/MWh effective January 1, 2022. The minimum contingency level was set to 3,000 MW of operating reserves to incentivize emergency generators and demand response providers to act sooner, thereby reducing the need for broader conservation appeals. The value of lost load (VOLL) is currently set to \$5,000/MWh, but the commissioners have directed that a study of the VOLL be performed and that the VOLL eventually be decoupled from the HCAP and given a new value. ERCOT will be required to report to the PUC on November 1 of each year on the “efficacy, utilization, related costs and contribution of the ORDC to grid reliability in ERCOT” ([Memorandum from Ben Haguewood, 2021, p. 2](#)).

### ***Demand Response***

A strategic aim of the PUC is to incentivize more consumers to conserve energy during times of peak demand. As the saying goes, it is much easier to turn off a load than to turn on a generator. However, the benefit to the system must outweigh the cost to compensate the demand response provider, which is usually not the case for residential or even large commercial consumers. Only certain industrial loads participate in the existing demand response programs. Therefore, the PUC is seeking to improve the transparency of price signals. A first potential step is shifting to more precise locational marginal pricing for demand response instead of zonal pricing. The blueprint also calls for setting higher performance standards for energy efficiency programs. Finally, the blueprint directs ERCOT to study how to better accommodate the participation of aggregated consumer demand response in the real-time and ancillary services markets.

### ***Reform and Expansion of Emergency Response Service (ERS) and Non-Spinning Reserves***

In the near term, the PUC is requiring the deployment of ERS sooner, and they intend to permanently codify the existing good-cause exception directing ERCOT to deploy ERS at the new minimum contingency level of 3,000 MW of operating reserves. This is being done to help avoid broader conservation appeals and to minimize the risk of reaching 2,300 MW of operating reserves and triggering an EEA1. Over the longer term, the commissioners want to explore whether it would be better to procure a specific quantity of resources instead of a specific dollar amount and to make the procurement seasonal rather than annual. ERCOT is already in the process of allowing loads to

participate in the non-spinning reserve program, and that implementation will continue.

### ***Fast Frequency Response Service (FFRS)***

ERCOT is creating a new ancillary service to address the frequency control issues associated with declining inertia ([Du et al., 2020](#)), which is a result of more inverter-based resources like wind and solar entering the market and replacing spinning generators like gas and coal that maintain the grid at a stable 60 Hz frequency. With fewer spinning generators contributing to grid frequency, deviations in the output of those resources have a greater effect on the grid frequency than if the entire grid was being supported by spinning generators. The proposed criteria for the service are that eligible resources should be able to automatically respond to a frequency drop within 15 cycles, maintain their output for 15 minutes, and be able to respond again in 15 minutes after being recalled ([p. 178396](#)). Resources that may be able to provide this service include energy storage and quick-start gas turbines.

### ***Voltage Support Compensation***

Another operational problem being introduced by wind and solar generation is that their high variability can make it difficult to maintain the voltage on transmission lines within their operational limits. The blueprint calls for a new voltage support service to be developed using resources, including energy storage and quick-start gas turbines, that can react to rapid swings in power input into transmission lines. The blueprint does not define the cost allocation for this program or the new ERCOT Contingency Reserve Service. However, the commissioners reiterated at the PUC open meeting on December 2, 2021, the need to follow the directive in SB 3 to allocate the costs of new ancillary services on a cost-causation basis ([PUC, 2021f, Part 2, 1:10:30](#)). That decision leaves open the possibility of allocating these costs to wind and solar generators as those generators are clearly creating the need for these services.

### ***ERCOT Contingency Reserve Service (ECRS)***

The ECRS program represents an expansion of existing ancillary services to address ramping needs and sudden drops in output due to forced outages and, increasingly, rapid changes in wind and especially solar output. The most immediate need is to address the fact that solar output declines far faster than demand during the early summer evening hours, leading to a rapid increase in demand on dispatchable resources. Also, on cold winter days when demand peaks at 8 a.m. and 8 p.m., the evening decline in solar occurs when demand is increasing. Given

these needs, Commissioner McAdams recommended that, as a starting principle, the ECRS program would be geared toward resources that can dispatch for at least two hours and that at least 2 GW would be procured ([Memorandum from Commissioner Will McAdams, 2021a](#)). ERCOT is still evaluating the program, and no firm decisions on duration, procurement, and sizing have been made as of this writing.

### Phase 2 Wholesale Market Reforms

While the Phase 1 programs in the blueprint are primarily focused on the near-term operational problems facing the ERCOT market, the Phase 2 proposals are focused on the longer-term resource adequacy problem. The commissioners seem united in their assessment that the energy-only market, especially with the distortions caused by subsidies for wind and solar, is not adequately driving investment toward dispatchable generation and reliability measures. In that sense, they appear to agree with the conclusions of this assessment and the ASCE assessment. However, their proposals to address this issue vary dramatically in nature and scope. In the end, three proposals were included in the final blueprint.

#### **Backstop Reliability Service: Commissioner Cobos**

Commissioner Cobos has authored the most straightforward proposal, which is to directly procure dispatchable generation to meet specific reliability and resource adequacy needs ([Memorandum from Commissioner Lori Cobos, 2021](#)). Because this service is procured and deployed in a similar manner to other ancillary services like ERS, it is a simple add-on to the existing market that can serve as a mechanism to bridge the gap while the PUC and ERCOT implement broader market reforms. In that sense, “stopgap reliability service” might be a better term to describe the program, as the commissioners have expressed a clear desire to reform the market to eliminate the need for this type of centralized capacity procurement. Given the urgent resource adequacy needs facing the ERCOT market over the next five years, the commissioners directed ERCOT to “develop the items related to the backstop reliability service and deliver that to the Commission as soon as practicable” ([PUC, 2022, p. 3](#)).

#### **Load Serving Entity (LSE) Obligation: Chairman Lake**

Chairman Lake has proposed a much broader market redesign proposal, dubbed an LSE obligation, wherein every load serving entity in ERCOT—including REPs, MOUs, and retail coops—must procure capacity in the forward energy markets and demonstrate that they have enough firm capacity to meet their peak demand ([Memorandum from Chairman Peter M. Lake, 2021b](#)). The original

proposal from Chairman Lake said that LSEs would be required to procure 50% of their load share ratio three years out, increasing to 100% one month out. However, the current blueprint does not contain a recommended size for the obligation.

The general concerns expressed regarding this program are that it is not transparent—because each entity procures capacity through confidential bilateral agreements—and that it would favor both larger REPs that have more flexibility to procure diverse resources and REPs that also own generation and therefore have a natural hedge. These concerns have not been fully resolved to date among the commissioners and market participants. In a sense, the argument against this proposal is that it imposes the same obligations as a capacity market but does so in a less efficient and transparent manner. However, the broader problem with it, as discussed below, is that it places the entire responsibility for firming directly on LSEs and therefore on ratepayers, with no check on the growth of variable resources that are driving the need for the firming.

#### **Dispatchable Energy Credits (DEC): Commissioner McAdams**

In a broad sense, this proposal attempts to mirror the Renewable Portfolio Standard established in 1999, and the corresponding Renewable Energy Credit program, with a Dispatchable Portfolio Standard (DPS) and a Dispatchable Energy Credit (DEC) program ([Memorandum from Commissioner Will McAdams, 2021b](#)). The DPS also harkens back to the goal for natural gas enshrined in PURA, Texas Utilities Code Sec. 39.9044 and the natural gas credit program mandated therein, while also being grounded in the mandates in SB 3 Section 18 to ensure sufficient dispatchable generation to meet the reliability needs of the ERCOT region. Unlike the goal for natural gas, the DPS would not be specific as to the type of resource procured, but Commissioner McAdams does suggest that qualifying resources be able to ramp to full nameplate capacity within 5 minutes. Any energy storage resource must be able to discharge at full capacity for at least two hours. Each LSE would have an annual DEC requirement based on their peak demand, and they can satisfy the requirement by either buying DEC or by making an alternative compliance payment that would go toward ancillary services.

A key element of all three proposals is that they allocate the costs of procuring new resources *to load*. While SB 3 Section 14 directs the PUC to allocate the cost ancillary services on a “cost-causation” basis, Section 18 offers no clear direction as to the cost allocation of new reliability

services. However, Gov. Abbott's July 6 letter clearly states that "we must ensure that all power generators can provide a minimum amount of power at any given time" ([Letter from Governor Abbott, 2021, p. 2](#)), which can only mean generation firming, that is, cost allocation of backup power to generators. Nevertheless, the commissioners unanimously decided at their December 2, 2021, open meeting to take generation firming "off the table" for the Phase 2 proposals ([PUC, 2021f, Part 2, 55:50](#)). The commissioners have yet to publicly explain why they made this decision.

It is important to reemphasize that the problem facing the ERCOT market is not just an underinvestment in dispatchable generation but an overinvestment in variable generation. Addressing only the underinvestment problem will inevitably lead to a dual system of subsidized dispatchable generation supporting subsidized variable generation. This is the model that Germany, California, and other regions with high wind and solar penetration are trending toward, and their electricity costs are rising because there is no check on the growth of wind and solar and on the costs their variability imposes on the grid system. The logical conclusion is that generation firming is *necessary*, not just to ensure that new wind and solar entrants do not degrade the reliability of the system, which is needed with or without subsidies, but also to correct for the distortions in the market caused by subsidies.

## Conclusion

ERCOT is predicting a surge of new wind and solar generating capacity over the next few years, up to 29 GW of total installed capacity, but less than a GW of new natural gas generation ([ERCOT, 2021h](#)). Meanwhile, summer and winter peak demand are expected to grow 5% and 6%, respectively, by 2025. In other words, the gap between demand and dispatchable capacity, which Winter Storm Uri showed is already dire, is only set to grow, and the ERCOT grid will continue to depend on wind and solar to meet demand growth. The storm showed conclusively that the ERCOT market is reaching the limits of how much dispatchable generation it can replace with wind and solar generation without severe reliability impacts. While the Phase 1 market reforms the PUC and ERCOT are implementing will help address some of the problems arising from the day-to-day and intraday variability of wind and solar generation, the question of how to address the resource adequacy problem remains unanswered.

The 87th Texas Legislature took a significant step to reduce the subsidies favoring new wind and solar generation by not renewing the Chapter 313 property tax abatement

program, which will expire at the end of 2022 ([Morris & Tedesco, 2021](#)). Reforms to the process for siting transmission projects following from SB 1281 could also force wind and solar projects to site closer to existing lines, instead of wherever the land is cheapest. However, federal subsidies will continue to wreak havoc on price formation in ERCOT market for years to come, as the production tax credit for wind generation extends 10 years from the start of operations. The investment tax credit that subsidizes a portion of the capital costs of solar generation, combined with the existing ERCOT price structure that tends toward high prices in the summer when solar is generating the most, will continue to drive new solar into the market.

Unless Texas changes the way the ERCOT market is structured to account for the reliability costs that wind and solar generators impose on the grid, more outages are going to be likely in the future. While the PUC may impose some of the costs of the Phase 1 market reforms on wind and solar generators, those reforms are not sufficient to ensure long-term resource adequacy. The existing scarcity pricing mechanism and ancillary services, even including the new Phase 1 programs, are only designed to ensure resource adequacy in a market where peak demand may vary by a few percent compared to forecasts, and the availability of generators is always greater than 90%. The existing market structure cannot account for an additional 30–40% uncertainty in combined wind and solar output during the hours of highest demand. If the ERCOT market is going to absorb more wind and solar, that generation needs to be firmed up with dispatchable energy sources.

For over a year, Life:Powered has been proposing to require variable generators to purchase a certain amount of dispatchable generation, energy storage, or demand response to firm up their output during peak demand periods ([Bennett, 2021b](#); [Isaac, 2021](#)). If these generators are going to remain a significant part of Texas' energy landscape, they need to improve the delivery of reliable electricity during peak demand periods, not make it more variable. Requiring them to pick up some of the cost of backup power will help balance the investment flows in the market and incentivize them to enter the market only when they can do so reliably, thereby minimizing the cost of backup power shouldered by ratepayers. Imposing this cost directly on ratepayers will cause the market to chase wind and solar subsidies with subsidies for dispatchable generators, resulting in a bifurcated market of subsidized variable generation and subsidized backup power that will place a heavy burden on Texans' electricity bills.

Another proposal was put forward in March by the South Texas Electric Cooperative (2022) that includes a broader firming requirement—encompassing wind, solar, and thermal generation, as well as load—and a method of cost allocation to generators, including wind and solar generators, that do not meet that requirement. Life:Powered (Isaac & Bennett, 2022) wrote comments to support many aspects of the proposal, in particular the cost allocation aspect, and the Texas Competitive Power Advocates (Letter from Michelle Richmond, 2022) and the Alliance for Retail Markets (Letter from Carrie Collier-Brown, 2022) also wrote in support of studying the proposal. Senators Schwertner and Nichols, the chair and vice chair of the Senate Business and Commerce Committee that has jurisdiction over the PUC, wrote a letter that included a request to the PUC to study different cost allocation methods (Letter from Sens. Schwertner and Nichols, 2022).

Unfortunately, the PUC has so far declined to open up a study of any proposals outside of the current Phase 2 proposals, which, as noted above, are fatally flawed because they place the entire cost of new backup generation and resource adequacy directly on ratepayers. Furthermore, the commissioners have hired a firm to study the Phase 2 proposals, Energy and Environmental Economics, that put forward the load-serving entity obligation at the bequest of

NRG (Olson et al., 2022). The PUC has the ability to apply a broader scope to this study and consider methods of cost allocation and firming to generators, as Chairman Lake indicated in his response to the letter from the senators (Letter from Chairman Peter Lake, 2022). However, the current scope of the contract does not require a study of cost allocation to generators (Contract No. 473-22-00009), and the commissioners need to make a specific request that Energy and Environmental Economics do so as part of their work.

Ensuring that the disaster of Winter Storm Uri does not happen again requires much more than simply appropriating more funding for weatherization and backup generation. Driving more investment into the market without correcting the underlying causes of unreliability will simply increase costs without ensuring a reliable grid over the long term. California and Europe are heading down that road, and Texas should not follow them. Instead, the PUC needs to balance the market and create a regulatory environment that can handle the out-of-market forces favoring unreliable generation without direct intervention by the PUC or ERCOT through curtailment or other costly measures. Texas must put reliable *and* affordable electricity first by leading with novel market reforms that counter the forces favoring unreliable electricity production. ★

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