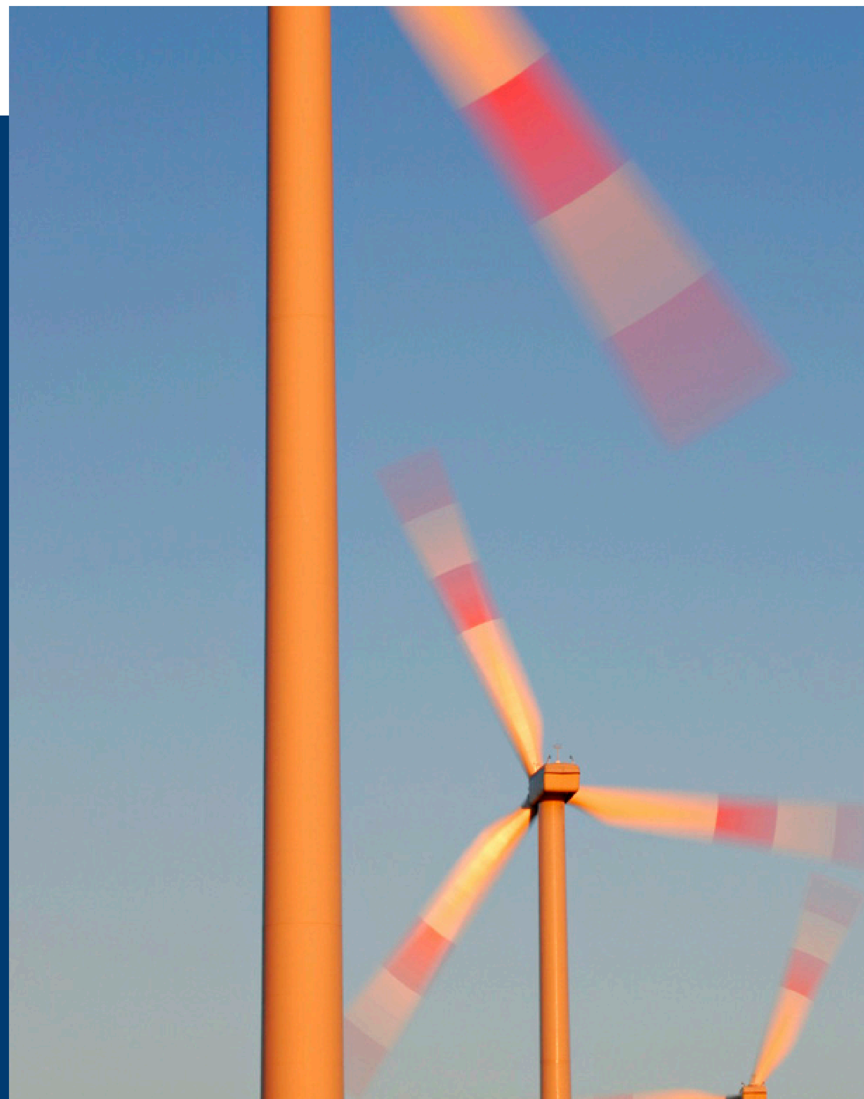
IMPROVING THE ERCOT GRID

THROUGH A RELIABILITY REQUIREMENT FOR VARIABLE GENERATION



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Executive Summary

As the cost to generate electricity from wind and solar continues to fall (Lazard, 2020), the widespread belief is that adding more wind and solar to the Texas electric grid will bring lower costs to Texas consumers. However, the increasing variability of Texas' electricity supply, coupled with growing demand, is beginning to strain the system's ability to provide enough electricity when it is needed the most on extremely hot or cold days.

Data from the Electric Reliability Council of Texas (ERCOT), which operates the grid that serves 90% of Texas' population, show that wind and solar generators are 5 to 10 times more variable in aggregate than gas, coal, and nuclear generators during peak-demand periods. The fact that it is difficult to predict in advance how much wind or sun will be present on the days of highest demand has exacerbated price volatility. It is now common to have very long periods of near-zero or negative wholesale prices when wind and solar resources are high, punctuated by very brief periods of high prices when low wind and solar resources line up with high demand. This lack of price certainty in the ERCOT market has squashed investment in dispatchable coal and natural gas generation and created a growing reliability deficit in the Texas grid, which led to two emergency alerts in August 2019 and was one of the root causes of the widespread and deadly outages during Winter Storm Uri in February 2021.

Despite hesitancy from regulators and lawmakers to alter the ERCOT market over the past decade, the outages during Winter Storm Uri prompted a swift response from Texas' elected leaders. The Texas Legislature passed Senate Bill 3 in May 2021, which directed the Public Utility Commission of Texas (PUC) to create new reliability standards and enact market reforms to ensure those standards were met. On July 6, 2021, Gov. Abbott issued a letter to the PUC (Letter from Gov. Greg Abbott to PUC, 2021) emphasizing the reforms that he expects to be implemented. Among his highlighted reforms was a directive to "allocate reliability costs to resources that cannot guarantee their own availability, such as wind or solar power." The purpose of this paper is to explain why such a requirement—also called a firming requirement—is needed and to assess the potential impacts of implementing it.

When assessing the need for a firming requirement for variable generators, it is important to keep several facts and principles in mind:

1. Serving ratepayers should be the primary purpose of electricity policy and market design.

Key Points

- The Texas electric grid is experiencing more frequent reliability problems, as evidenced by tight summer conditions from 2018 to 2021 and most of all during Winter Storm Uri.
- An increasing reliance on wind and solar generation, which is directing investment and revenue away from dispatchable generation and reliability measures, is the primary cause of these shortages.
- Placing reliability costs on ratepayers, as the Texas model has done to date, provides an implicit subsidy for less reliable generators. The necessary solution to improve reliability is to redirect investment away from variable generation and toward reliability measures.
- A requirement for variable generators to provide a minimum amount of electricity during high-demand periods will improve reliability while minimizing overall costs and impact on the rest of the competitive market.
- This requirement could provide nearly 5 GW of reliable backup resources at a cost of less than $500 million annually, far less than the billions of dollars that Texas ratepayers have paid over the past several years through increased scarcity prices.

2. The Texas model of socializing transmission and reliability costs among ratepayers provides generators with an implicit subsidy and favors generators that impose more transmission and reliability costs on the system.
3. Failing to allocate reliability costs to variable generators will result in increasing costs for backup power or in more frequent reliability problems, as Texas is experiencing. Neither outcome is optimal for consumers.
4. Allocating more of these system-level reliability costs to generators will bring more balance to the market and provide an incentive for generators to minimize those costs, thereby lowering the overall cost to ratepayers.

Requiring variable generators to provide a minimum amount of electricity to the ERCOT grid during peak-demand periods would reduce the volatility of prices and supply, help prevent the premature retirement of existing generation, and ensure that any additional generation added to the grid will come with adequate backup power. Wind and solar are the only significant sources of weather-dependent generation in the Texas market today, but the requirement should apply generally to any similar resources. A firming requirement for these generators and consistent reliability standards are essential reforms for returning balance to the Texas market, preventing catastrophic outages such as those during Winter Storm Uri, and maintaining affordable and reliable electricity for Texans for decades to come.

Introduction

Wind and solar are the fastest-growing sources of electricity generation in the Texas electricity market, primarily driven by federal and local tax subsidies (Erickson, 2018), ample wind and solar resources, ease of development, and transmission costs being charged to customers and not developers. In fact, between the summers of 2021 and 2024, the Electric Reliability Council of Texas (ERCOT) expects almost 38 GW of renewable generation to come online, compared to a little more than 1 GW of natural gas generation (ERCOT, 2021a, pp. 18–19). This capacity growth will be accompanied by peak-demand growth of more than 6 GW. While the forecast capacity additions seem large relative to demand growth, it is likely that not all of that capacity will be built. Also, renewable generation contributes far less to meeting peak demand than thermal resources such as nuclear, coal, and natural gas. ERCOT estimates that wind in the Panhandle contributes 29% of its total installed capacity during peak hours on average, while solar contributes an average of 80% of its total capacity (p. 10).

While any source of variability in supply creates problems for the grid, including sudden outages of thermal power plants, the unpredictable nature of wind and solar is unique. Those resources are also the only significant sources of weather-dependent generation in the ERCOT market. Hence, this paper will use the terms "variable," "renewable," and "wind and solar" interchangeably, even though all generation resources are variable to some degree, and renewable generation is not limited to wind and solar.

Although wind and solar can generate electricity at a low cost because their fuel costs are zero, their inability to generate in concert with demand creates significant problems and extra costs for the ERCOT market. Large amounts of variable generation in the market strain the ability of thermal generators to ramp up and down and reduce their efficiency, lead to unexpected shortages during periods of high demand, and cause extreme price uncertainty. The unsubsidized cost of building new wind and solar (Lazard, 2020) is still at or above the average wholesale price of electricity in Texas (Potomac Economics, 2021, p. 7) but subsidies are continuing to drive new generation into the market. This excess generation above what the market would normally demand depresses prices and destabilizes the economics of existing generation. The production tax credit further encourages wind generators to bid prices that are below the marginal cost of production and even below zero (Potomac Economics, 2021, p. A-12), putting additional economic pressure on generators, especially coal and nuclear generators, that are more reliable but lack the flexibility to turn on and off quickly.

In recent years, the lack of growth in dispatchable thermal generation and the highly variable generation of new renewable resources have led to increasing scarcity. The first indication of how tight the ERCOT market has become was two Energy Emergency Alerts (EEAs) in August 2019 (ERCOT, 2019a). Reduced peak demand due to the COVID-19 pandemic in 2020 provided a reprieve from electricity supply problems (Potomac Economics, 2021, p. i), but Winter Storm Uri in February 2021 exposed these problems in their entirety. A deeper analysis of that event will be provided in a separate study. This study will focus primarily on the effects of wind and solar variability on the ERCOT market and how that variability can be mitigated in a way that minimizes costs to consumers.

One step the Public Utility Commission of Texas (PUC) took to address this growing scarcity problem was to change an administrative scarcity pricing mechanism called the Operating Reserve Demand Curve (ORDC) in January 2019 (Potomac Economics, 2020, p. ii). This change caused prices paid to generators to increase by approximately $2 billion in 2019 (p. 80). Unfortunately, these price increases have done little to incentivize new dispatchable generation or to encourage renewable generation to deploy energy storage or other means to produce more electricity during peak-demand hours. Since the ORDC is also paid to renewable generation, those generators benefit from the higher prices in the same way as other generators without having to improve their reliability. Also, increasing the ORDC does not reduce the price volatility that is hampering investment in dispatchable generation.

Increasing use of wind and solar generation imposes a reliability cost on customers. While ERCOT estimates the contribution of renewable generation to meeting peak demand based on an average expected output during a defined peak period, the actual output of renewable generation varies considerably. Thermal generators consistently contribute more than 90% of their peak output during peak-demand periods (Potomac Economics, 2021, p. 84). Yet during the top 100 summer-demand hours over the last 5 years, renewables contributed between 16% and 46% of their aggregate installed capacity (see **Figure 4**), making them up to 10 times more variable than thermal generation.

This is the key problem with any form of weather-dependent generation. The uncertainty in how much solar and wind will be available during peak periods is a major driver in the extra cost paid by consumers through the ORDC. Socializing this reliability cost across all electric consumers, which is the current policy in Texas, does not balance the market or encourage more reliable generation. The best way to ensure reliability and bring balance to the market at the lowest cost possible to consumers is to require variable generators to provide a firm amount of capacity during peak-demand periods, comparable to how dispatchable generation must provide firm capacity to participate profitably in the market. This can be done by requiring these resources to pay for firming capacity during peak periods in the summer and winter. The cost for variable resources to provide this service will be much lower than the cost imposed on consumers through the ORDC and will do a better job of incentivizing reliability.

Resource Adequacy and Scarcity Pricing in ERCOT

Each year, ERCOT publishes an estimate of expected demand and the capacity available to meet peak demand (ERCOT, 2021a). Such a projection is required by the North American Electric Reliability Corporation (NERC, 2021) for evaluating resource adequacy. ERCOT estimates the capacity from natural gas, coal, nuclear, and hydroelectric generation from those resources' demonstrated output at peak conditions. Typically, the outage rate for these generators is used to determine the necessary reserve margin over peak demand. The more uncertain resource availability is, the higher the required reserve margin. However, ERCOT does not require utilities to meet a required reserve margin, as would be the case in a capacity market. Instead, it has a target reserve margin that informs policymakers on whether reliability is adequate, and it uses market prices to attract new generation.

ERCOT estimates the peak contribution for renewable resources using the average of the actual renewable output over the peak 20 hours of demand for a given year, averaged over a 5 (for solar) and 10 (for wind) year history (ERCOT, 2020a, pp. 3–49). This averaging process obscures the high variability in wind and solar. For instance, wind facilities on average operated at 33% of their installed capacity in the top 20 hours of 2019. But for the hour ending at 4 p.m. on August 15, 2019—during the second EEA1 called by ERCOT that week—wind only provided 9% of its installed capacity (ERCOT, n.d.-a, "Fuel Mix Report: 2007–2020").

Similarly, solar resources are expected to contribute 80% of capacity during summer peak conditions, but during several of the top 20 demand hours between 2016 and 2020, solar provided less than 60% of its installed capacity (ERCOT, n.d.-a, "Fuel Mix Report: 2007–2020"). That shortfall was inconsequential in those years, with solar only a small percentage of grid capacity. However, when solar capacity reaches the 20 GW level expected in 2022 (ERCOT, 2021a, p. 10), it could be the difference between $20/MWh and $9,000/MWh prices, and perhaps reliable operation and rotating outages.

During the peak summer-demand hours from 2015 to 2019, wind and solar were each more than 10% below their expected output nearly a third of the time and sometimes produced less than half their expected output (ERCOT, n.d.-d, "ERCOT Wind Profiles" and "ERCOT Solar PV Profiles"). ERCOT evaluates low wind output hours as the 95% confidence limit that output will be at or above that level, which is about 6% of installed capacity (ERCOT, 2021b, p. 4). Given the paucity of solar generation prior to 2020, ERCOT only recently published a number for low solar output using 2020 data, pegging it at 27% of installed capacity. However, a similar treatment of the data over the past 5 years suggests a low solar output estimate of about 55% of installed capacity (see **Figure 1**), which is still well below the 80% average that is in the official reserve margin calculation (p. 2).

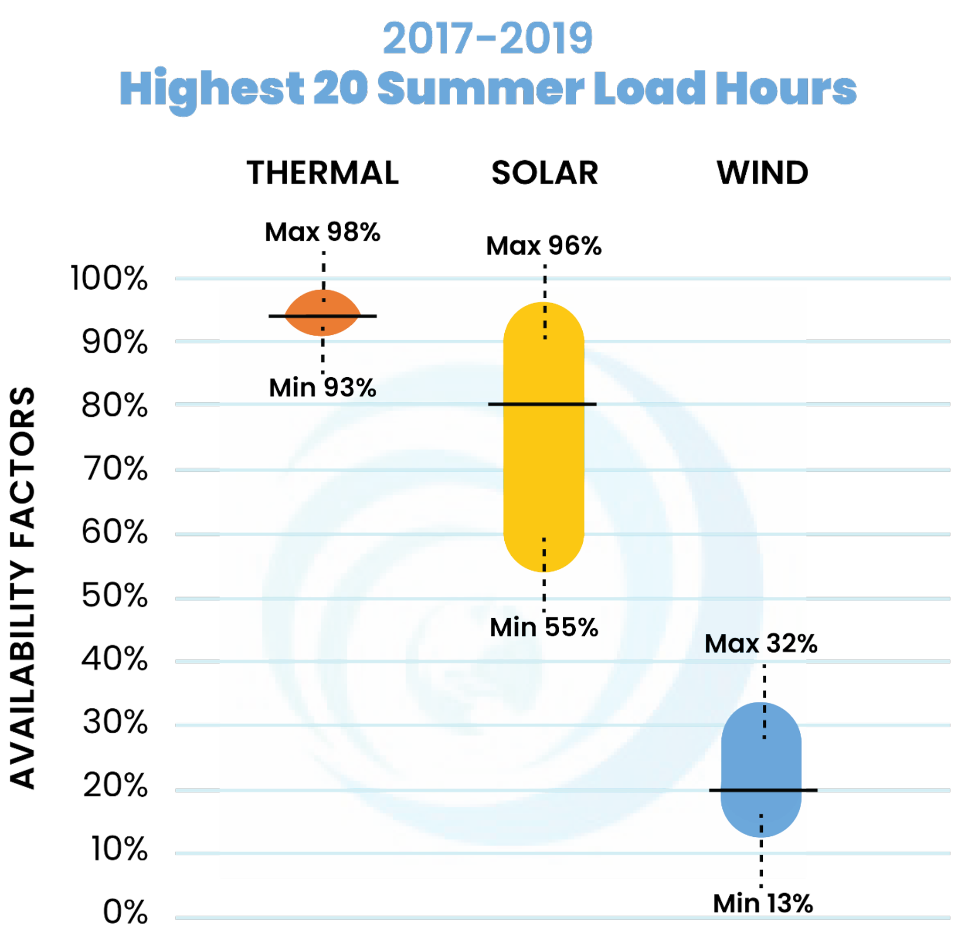
The full distribution of aggregate solar, wind, and thermal generation during the top 20 peak-load hours in each year from 2017 to 2019 is shown in **Figure 1** as a percentage of installed capacity. Wind output varies by roughly 10% above or below its expected output of 20% of installed capacity, or a variance of about ±50%. Solar output can easily fall 25% below its expected output of 80% of installed capacity. A similar distribution of the availability of dispatchable thermal generation shows a relatively narrow distribution between 93% and 98%, which is a variance of only 3%.

The current pricing structure of the ERCOT market, which is designed to incentivize dispatchable generators to increase or decrease production to match changes in demand, is wholly inadequate to manage a system with a highly variable supply. The current market rules in ERCOT send price signals to developers via the ORDC (ERCOT, n.d.-c). This mechanism creates higher prices when expected operating reserves start shrinking, and it sends prices to the maximum ($9,000 per MWh) when operating reserves are so low that a shortage is imminent. It is a function of both operating reserve level and the expected change in operating reserve level over the next 30 minutes.

Even in the absence of market distortions such as subsidies, the high variance of renewables from their expected output will cause extreme price volatility in the ERCOT market and make it difficult to invest in reliable generation assets over the long term. Adding to this problem, the primary drivers of wind and solar development are federal tax policies that have provided an average of $19/MWh and $82/MWh

Figure 1

Distribution of Wind, Solar, and Thermal Output in ERCOT During Peak-Demand Hours, 2017–2019



Note. Thermal data from ERCOT (proprietary).Wind and solar data from *Resource Adequacy*, "Wind Profiles, Operational-Planned, 1980–2019" and "Solar PV Profiles, 1980–2019," ERCOT, n.d.-d (http://www.ercot.com/gridinfo/resource).

in subsidies since 2010 for wind and solar generation, respectively (Bennett et al., 2020). Therefore, a market that depends on prices to incentivize generators to meet demand is being inundated with generation assets that are profitable even when they do not produce electricity during the times of highest demand.

These subsidies, combined with Texas' abundance of wind and solar resources, low land prices, ease of development, and socialized transmission costs, have made the state a focus for renewable development, despite the fact that market prices are too low to support new generation on their own. While recent moves by the PUC to increase ORDC pricing may have helped maintain some existing thermal generation, the only effect of the change on net was an increase in solar generating capacity, which will create further reliability problems in the future.

Growing Summer Reliability Problems in the ERCOT Market

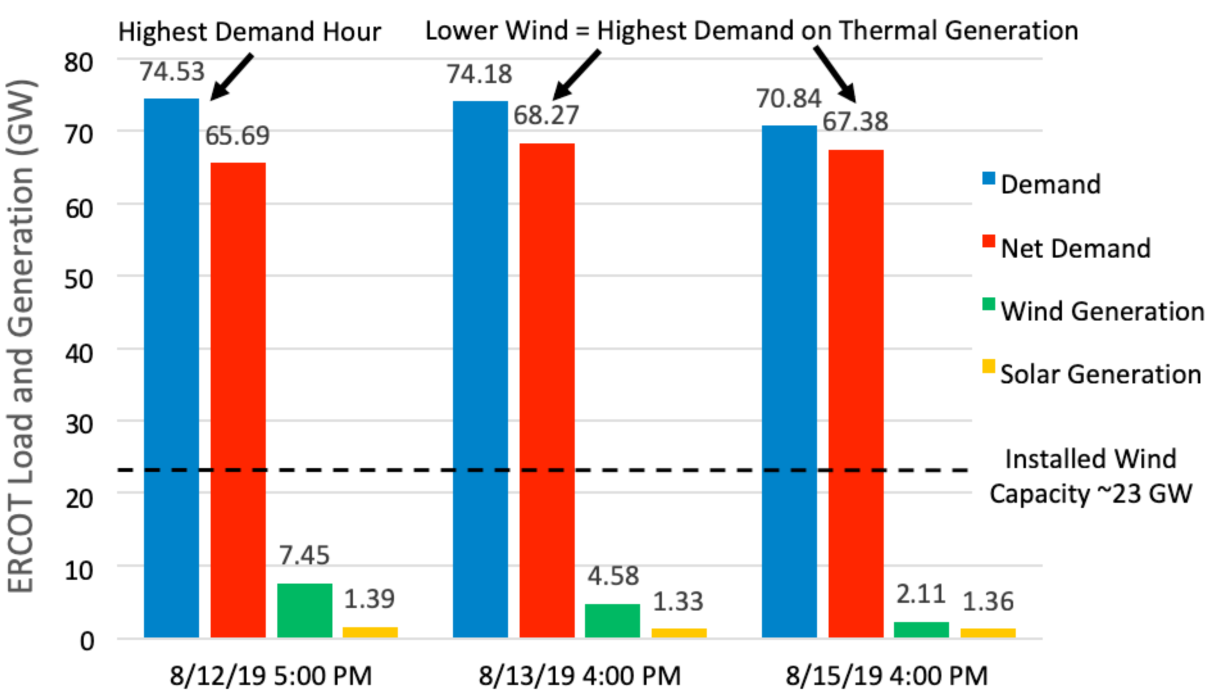
In 2019, the lack of reliable generation during peak-demand hours began to create serious problems. On two occasions, during the afternoons of August 13 and August 15, ERCOT had to issue EEA Level 1 alerts due to reserves falling below 2,300 MW. This meant that the grid was only a few power plant outages away from being short of supply, necessitating the use of emergency resources. Fortunately, through conservation and better-than-expected performance of dispatchable generation, rolling blackouts were avoided.

What was unique about these two events was that they did not occur when demand was at its highest, which was on August 12. They occurred on subsequent days when a combination of high demand and low wind output led to the highest demand on dispatchable generation, which is labeled "net demand" in **Figure 2**. In other words, this was the first time in Texas history when low wind output was a noticeable driver of an emergency. The days of highest net demand are the days when the risk of a shortfall is the highest, and those days no longer necessarily correspond with the days of highest total demand, adding a new layer of uncertainty to the to the ERCOT market.

The year 2020 might have seen even worse problems if peak electricity demand had increased by 2,000 MW, as was projected prior to the COVID-19 pandemic (ERCOT, 2019b). Instead, peak demand decreased by about 500 MW compared to 2019 due to reduced economic activity caused

Figure 2

ERCOT Load and Generation During Select Hours of the Week of August 11, 2019



Note. Data from *Hourly Electric Grid Monitor*, "Electric Reliability Council of Texas, Inc. (ERCO) Electricity Overview," U.S. Energy Information Administration, n.d. (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO).

by the COVID-19 shutdowns (Potomac Economics, 2021, p. i). Had peak demand met the initial projections on August 14, 2020, the demand on dispatchable generation would have been about 1,700 MW higher than it was on August 13, 2019. Since no net dispatchable generation was added in 2020, this situation easily could have led to an EEA Level 3 (ERCOT, 2019c), which would have precipitated rolling outages.

The summer of 2021 was also a reprieve for the Texas grid after the disaster of Winter Storm Uri, thanks to very few occurrences of temperatures above 100 degrees across the state. A brief heat wave in June, which coincided with very low wind output and a large number of power plants that were offline for maintenance, prompted an unexpected conservation alert. However, the grid was never stressed again as temperatures remained mild throughout the summer and demand never exceeded 74 GW (ERCOT, n.d.-b, "2021 ERCOT Hourly Load Data"), far below ERCOT's projection of 77 GW (ERCOT, 2021b, p. 2).

There is only about 72 GW of thermal generation available in ERCOT (ERCOT, 2021b, p. 2), which is roughly equal to peak summer demand in 2021. As mentioned previously, the capacity of thermal generation in ERCOT is not expected to keep pace with demand growth over the next 5 years. The normal summer outage rate for the thermal fleet is 3–4 GW(Potomac Economics, 2021, p. 84), so any situation that places 68 GW or more of demand on that fleet precipitates a risk of a shortage. While such a situation was avoided in the summers of 2020 and 2021, Winter Storm Uri exposed the entirety of the problems with the Texas market.

The Shortage of Firm Capacity During Winter Storm Uri

The failure of the Texas grid during Winter Storm Uri was a combination of many problems, but most of the public and media attention has focused on the 30 GW of thermal power plants that were offline during the height of the event (ERCOT, 2021c, p. 12). The extreme level of demand, which was forecast to exceed the previous winter record by more than 10% (U.S. Energy Information Administration, n.d.) had the blackouts not cut it back, caught grid planners and operators by surprise. About 12 GW of thermal generation was offline for planned maintenance or due to problems unrelated to the weather (ERCOT, 2021c, pp. 18–19), and another 18 GW was out due to primarily weather-related factors, including equipment freezing and natural gas supply shortages (p. 18).

Although much attention was also put on the fact that half of the state's wind turbines were down due to icing and many solar panels were covered in snow, the operational issues for wind and solar generators were far less of a problem than the lack of wind and solar resources, especially during the times of highest demand. ERCOT estimates that wind production would have been roughly twice what it was if the weather problems did not occur, but even in that case, wind would have produced only a few percent of its installed capacity during the height of the storm on the night of Monday, February 15—far less than the 20% expected capacity value predicted by ERCOT for the winter season (ERCOT, 2020b).

Therefore, while the weather issues garnered most of the headlines, the important fact that was largely missing from the public discussion is that Texas never had enough firm capacity to make it through this event without shortages.

Table 1
Causes of Thermal Power Plant Outages During Winter Storm Uri

Outage type	Description	Outages or derates (GW)	Percent of total
Weather-related	Gas power plant weather outages	7.5	25
	Natural gas fuel supply shortages	6	20
	Coal and nuclear weather outages	4.5	15
Other	Long-term maintenance	7.5	25
	Other equipment outages	4.5	15
Total		**30**	**100**

Note. Data from *Update to April 6, 2021 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event*, ERCOT, 2021c (http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf).

Table 2

Installed Capacity of Generation Resources in ERCOT Compared to Output During Winter Storm Uri

Installed capacity		February 9–19		Monday, Feb. 15, 8 PM	
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%

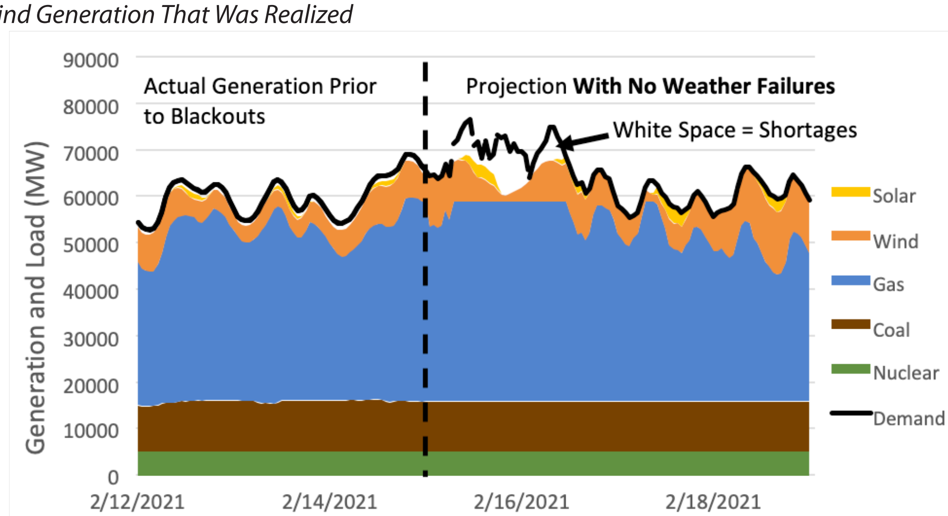
Note. Data from *Seasonal Assessment of Resource Adequacy for the ERCOT Region: Winter 2020–21*, ERCOT, 2020b (http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.pdf); *Hourly Electric Grid Monitor*, "Electric Reliability Council of Texas, Inc. (ERCO) Electricity Overview," U.S. Energy Information Administration, n.d. (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO).

Even without the 18 GW of weather-related outages for thermal power plants and without any wind turbine icing, the combination of high demand, low wind speeds, and little sun meant that there would have still been a period of over 24 hours between Monday, February 15, and Tuesday, February 16, when demand would have exceeded supply. This conclusion can be derived by comparing the forecasted demand for those periods to the amount of thermal generation that was online Sunday night plus double the wind generation that was present—roughly equivalent to the back-casted wind generation profiles produced by ERCOT. As shown in **Figure 3**, even without any weather-related outages, the gap between total generation (stacked blocks) and forecast demand (dotted lines) would have reached nearly 10 GW by Monday at 8 p.m. The shortage of thermal generating capacity to serve the demand and the predictably low amount of wind and solar resources during this event made some degree of blackouts inevitable.

Again, it is important to emphasize that the root cause of this event is more than a decade of policy that has caused the Texas market to underinvest in reliable generating capacity. The operational and weather problems on February 15 and 16, 2021, turned what might have been a manageable rolling blackout situation into a catastrophic multi-day event, but they were not the root cause.

Figure 3

Actual Demand and Generation (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. (ERCO) Electricity Overview," U.S. Energy Information Administration, n.d. (https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO).

Fundamentally, the problem is that Texas is pouring billions of dollars into wind and solar development that will never produce enough electricity during these extreme weather events, rather than maintaining and adding to its thermal fleet that can perform during these events.

Unfortunately, the situation is unlikely to improve in the near term. The average pre-COVID growth rate in peak demand was about 1,600 MW annually, or about 2%, so events where net demand exceeds 70 GW will become increasingly likely in both the summer and the winter. Even with the explosion of solar capacity that is underway, some recent models, using post-COVID demand estimates, still project that shortages could occur more than 50 times annually by 2027 if the ERCOT market continues on its current path (Preston, 2020).

Legislative and Regulatory Responses to ERCOT's Reliability Problems

Prior to 2021, the PUC's most significant response to the growing reliability problem in Texas was the 2019 alterations to the ORDC to provide higher revenue to generators. The Independent Market Monitor (IMM) for ERCOT estimates that the ORDC changes increased prices by 12%–13%, or approximately $2 billion, in 2019 (Potomac Economics, 2020, p. 80). But these extra payments are made to all generators that produce during scarcity periods, regardless of their ability to guarantee their future availability. Therefore, the ORDC is not incentivizing wind and solar generators to improve their reliability or correcting the price volatility that is preventing investment in new dispatchable generation (Potomac Economics, 2021, p. 19). When the sun shines and the wind blows, energy prices are still too low for dispatchable generators to cover their fixed costs, and it is difficult for them to continue operating in the hope of making a profit for a few days out of the entire year. As a result, ERCOT is currently forecasting only about 1 GW of new dispatchable generation over the next 5 years, despite forecasted peak demand increasing by more than 1 GW per year (ERCOT, 2021a, p. 10).

Wind and solar generation, on the other hand, is set to explode over the next three years, with 14 GW of wind and 24 GW of solar in the planning stages (ERCOT, 2021a, pp. 18–19). Based on the data in **Figure 4**, the new solar resources, if they are all built, should contribute, on the low end, about half of their installed capacity, or 12 GW, in the summer. The new wind might be counted on for about 15% of its capacity or 2 GW. However, in the winter, when there is no sun during peak demand hours, these additions will help very little. Meanwhile, the continued suppression of prices during off-peak hours is likely to cause more retirements of dispatchable generation than the 1 GW of new generation that is forecast to be built. Combined with demand growth of 4–5 GW over the next few years, it is clear that the reliability of the Texas electric grid will be under duress for the foreseeable future.

Despite the historical reluctance of lawmakers and regulators to consider significant changes to address these reliability issues, the timing of Winter Storm Uri during the 87th Texas Legislature prompted the most comprehensive discussion of market reforms in over 2 decades. The first outgrowth of that discussion was Senate Bill 3 (2021) in the regular session, which proposed reforms ranging from weatherization mandates to restrictions on wholesale-indexed rate plans. Two sections of the bill direct the PUC to enact important wholesale market reforms:

- Section 14, which requires ERCOT to modify the design, procurement, and cost allocation of ancillary services.
- Section 18, which requires the procurement of reliability services for extreme summer and winter weather events and for periods of low wind and solar production, the reform of the scarcity pricing mechanisms in ERCOT (presumably including the ORDC), and the creation of a special pricing program for long-term emergencies.

Following the surprising conservation alert in June 2021 and pressure for the Legislature to enact more specific market reforms, Gov. Greg Abbott issued a letter on July 6, 2021, that directed the PUC to focus on several items (Letter from Gov. Greg Abbott to PUC, 2021):

- Improve incentives to foster the development of reliable fossil fuel and nuclear generation.
- Require generators that cannot guarantee their availability to shoulder their reliability costs.
- Require ERCOT to improve its seasonal maintenance scheduling.
- Accelerate specific transmission projects that improve the connectivity between dispatchable generation and regions with high electricity demand.

The second point speaks precisely to what this paper proposes—that variable generators, not consumers, pay for the reliability costs imposed by their variable output. There are several reasons why this form of cost allocation is necessary:

1. The primary purpose of electricity policy and market design should be to serve ratepayers. Too often, regulatory decisions are made with the goal of either favoring certain market sectors or "leveling the playing field," while the cost to ratepayers and risk to reliability are not given enough consideration.
2. When transmission and reliability costs are paid by ratepayers, as is currently the case in Texas, generators receive an implicit subsidy to enter the market. Generators that require more transmission and more backup power, such as wind and solar, receive a greater subsidy, leading to market imbalances.
3. If reliability costs are not allocated to generators, the ERCOT market will bifurcate into an expensive system of subsidized wind and solar generation and subsidized backup generation. If ratepayers fail to pay enough for backup generation, as is happening in Texas right now, they will shoulder the cost of more blackouts.
4. Allocating more of these system-level reliability costs to generators will reduce imbalances between more and less reliable generators. Generators will pass the costs to ratepayers, but the overall cost will be lower because generators will have an incentive to minimize the costs and will only enter the market to the extent that they can provide electricity in a reliable manner.

One means to achieve this goal, which the rest of this paper will explore in more detail, is to allocate the cost through a new ancillary service charged to those generators. This service would likely cost far less than the 2019 changes to the ORDC and would be more effective at ensuring reliability during peak-demand periods.

An Ancillary Service for Variable Resources to Provide Firm Capacity

The primary wholesale market in ERCOT procures energy on a minute-to-minute basis to meet electricity demand. ERCOT also has a secondary market, called the ancillary services market, that procures short-term reserves to meet unanticipated events and compensates generators for other services that keep the grid stable. Currently, ancillary services are paid for through a fee imposed on customers, but Senate Bill 3 opened the door to changing this allocation. This paper proposes a new ancillary service to firm up the expected output of variable generators to a level needed to ensure adequate reliability across the entire grid, allocating the cost to those generators according to cost-causation principles.

The procurement of this service should be based on the amount of capacity necessary to enable renewables to produce their expected output with the same level of reliability as dispatchable resources over the peak-demand period. The ERCOT State of the Market Report (Potomac Economics, 2021, p. 84) notes that the equivalent outage rate for dispatchable resources during peak summer-demand periods from 2017 to 2020 is approximately 5%. Under this proposal, variable generators would be required to pay for capacity capable of providing the same level of reliability as a dispatchable unit, for example, 95% of its expected output during the peak period. This proposal will cut down on the reliability deficit being imposed by variable generation and appropriately place the cost of the service on those resources instead of on ratepayers.

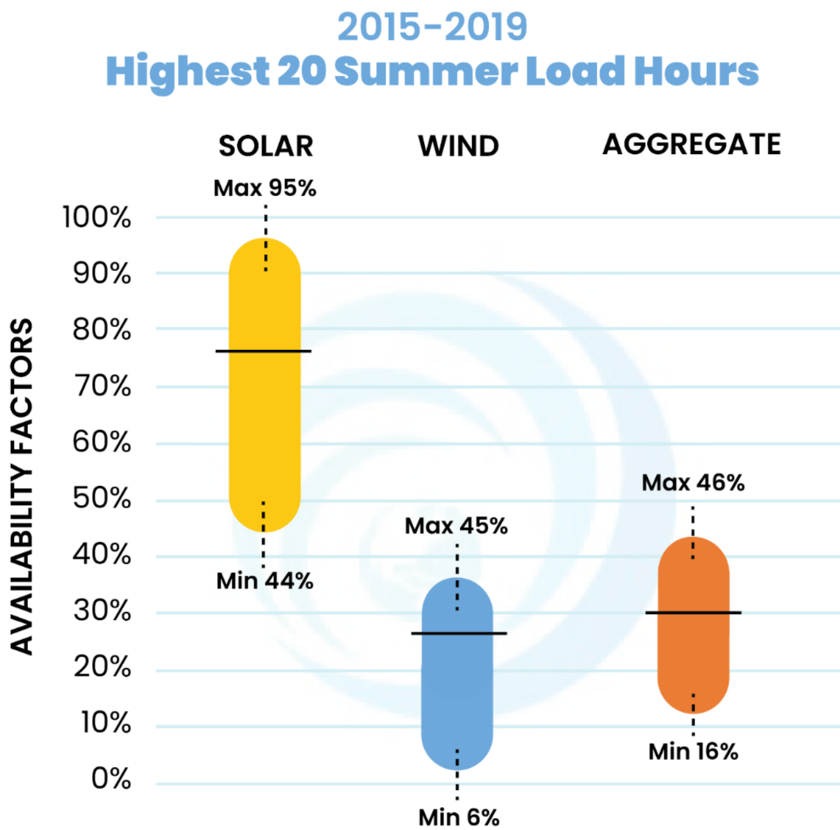
Currently, wind and solar generators often produce 40% less than their expected output during peak periods (see **Figure 4**). A reserve margin of 10% to 15% is not adequate when a large portion of the resources may produce 40% less than their average. Yet ERCOT continues to calculate its planning reserve margin using the average output of wind and solar during peak periods. Only by reducing the volatility of wind and solar to 5% with firming can the ERCOT market operate reliably with a 10% to 15% reserve margin.

The duration of the ancillary service is also an important consideration. Each summer, the 20 peak-demand hours almost always occur between 2 p.m. and 7 p.m., with a normal distribution about the 4 p.m. hour (see ERCOT, n.d.-b, "2021 ERCOT Hourly Load Data"). Therefore, the period for the summer ancillary service could be defined as the 5 hours from 2 p.m. to 7 p.m. Any resource used for firming would have to be able to operate continuously throughout that entire period. Winter storms tend to produce longer periods of high demand, but that level of demand is not usually as high as in the summer (with the obvious exception of Winter Storm Uri). Therefore, the winter firming requirement might be for a lower capacity value over a longer period, probably 24 hours or more.

It is important to note that the goal of the firming requirement is to improve the reliability of wind and solar resources in aggregate since their aggregate output is what matters for system reliability. This will also enable the requirement to account for the advantages of resource diversity. Low wind and sun output can sometimes be correlated during a winter storm when the weather is cloudy and calm. However, they are often anti-correlated in the summer, during which the wind tends to be lowest

Figure 4

Aggregate Availability Factors of Wind and Solar During Peak-Demand Hours, 2015 to 2019



Note. Data from *Resource Adequacy*, "Wind Profiles, Operational-Planned, 1980–2019" and "Solar PV Profiles, 1980–2019," ERCOT, n.d.-d (http://www.ercot.com/gridinfo/resource).

in the midday hours when the sun is at its highest. For example, consider the distribution of the aggregate summer output of wind and solar from 2015 to 2019 shown in **Figure 4**.

Using ERCOT's methodology (average of the top 20 peak hours per year), the expected peak summer output would be 30% of installed wind and solar capacity. But the 95% confidence level is only 18% of peak capacity. The firming ancillary service would require wind and solar in aggregate to purchase firming assets equal to 12% (30%–18%) of their installed capacity on a year-ahead basis for the peak hours of the summer. This procurement will ensure that their variability—that is, their low output relative to their expected output—is not more than that of other generation assets.

While the total size of the firming requirement would be determined by the aggregate wind and solar output, the PUC will need to assign different costs to different renewable generation types and locations—Panhandle wind, coastal wind, solar, etc.—based on their generation profiles during different times and seasons. Distinguishing between resource types is especially important when accounting for summer and winter services. The expected output of solar is about 80% during peak summer hours, but it is near zero during the winter peak-demand hours of 7–9 a.m. and 7–9 p.m. Therefore, solar would have a negligible firming requirement during the winter period under the proposed service. In this case, an equitable cost allocation might average the firming cost for solar resources over the summer and winter, instead of all the cost being assigned in the summer.

As the penetration of renewable resources grows, it will likely be necessary for the PUC to increase the size and duration of the firming requirement beyond the expected output during peak hours to ensure reliability. For example, previous modeling from our team indicates that 80% or greater wind and solar penetration would likely require twice as much combined wind and solar capacity as peak demand (Bennett, 2019), which would in turn require firming to 50% of installed capacity instead of 30% and a much longer duration for the requirement.

ERCOT would be responsible for qualifying resources to provide the firming service under the same criteria as it uses for a comparable ancillary service such as responsive reserve service. The amount and duration of the service should be calculated annually and procured as soon as possible after the previous year's peak period. Examples of potential qualifying resources are thermal generation, energy storage, distributed generation, and load resources. Each wind or solar facility would then be responsible for its allotted cost from ERCOT, although it could also elect to provide its own firming service. For example, batteries co-located with solar or wind could provide all or part of the firming service if they meet the duration and availability requirements.

Economic Impacts

By requiring a minimum level of firm capacity from variable resources, reliability will be enhanced by reducing the low-end variance of those resources. Higher levels of operating reserves will lower prices to consumers but not to thermal generators, as would happen without the requirement. Rather, the other resources will be paid by the renewable resources annually to provide reserves. Charging renewable resources for the cost they impose on the system may only marginally affect their development decisions, which are largely driven by federal tax subsidies and procurement decisions by local governments and private companies that are extraneous to prices in the ERCOT market. However, this requirement will ensure that renewable resource development does not compromise electric reliability in ERCOT, that other generators are compensated to provide reliability, and that customers get reliable power at the lowest possible market price.

In 2020, ERCOT had 28,941 MW of wind and solar capacity (ERCOT, 2020c, pp. 16–17). A firming service of 12% of installed capacity, as proposed in the previous section, would equate to a procurement of 3,473 MW of capacity from other sources. The ERCOT IMM estimates the cost of new entry for a gas combustion turbine at a minimum of ~$95/KW-year (Potomac Economics, 2021, p. 72), which results in an annual cost of the ancillary service of approximately $330 million. In 2020, wind and solar facilities produced 95.8 million MWh (ERCOT, n.d.-a, "Fuel Mix Report: 2007–2020"), so the cost would be $3.45/MWh on average. Wind and solar installed capacity grew to 39,656 MW in the summer of 2021 (ERCOT, 2021b, pp. 10–13), which would equate to a firming requirement of 4,758 MW at an annual cost of about $450 million.

The IMM notes that actual costs for new units are likely to be significantly lower for a variety of reasons (Potomac Economics, 2021, p. 78). Also, competition from load resources, distributed resources, and lower capital cost aeroderivative gas turbines would lower the expected cost of firming capacity. In any case, this is a small fraction of the cost of the recent ORDC change. Furthermore, ancillary service payments are only a cost in peak hours when renewables are not setting the price in ERCOT, so the cost would not necessarily be passed on directly to consumers.

While this paper proposes a firming ancillary service as the most straightforward way to improve the reliability of wind and solar generation, other methods have been proposed. The PUC submitted for comment the idea of requiring generators to make a minimum commitment in forward markets as a precondition for participating in the real-time market (Memorandum from PUC, 2021). However, the problem with wind and solar is not their variation from their predicted performance a few days or a week in advance, which is usually less than 10%. The problem is that it is almost impossible to determine months to years in advance, which is the time needed to procure backup generation, what the performance of wind and solar will be on the days of highest demand. As this paper highlights, their output can vary by up to 40% of their installed capacity on peak-demand days. A forward market commitment would not guarantee a level of backup power that can account for this level of variability.

There could be other approaches to reallocate reliability costs, and a final regulatory framework may include a blend of approaches in addition to the ancillary service proposed here. For example, the PUC could allocate ORDC payments based on a generator's ability to guarantee its availability on a seasonal basis. This change would more closely align the payment structure with the regulatory goal of the ORDC to incentivize true reserve power, instead of the as-available power from wind and solar, but it would create a complicated two-tier payment structure and add to transaction costs. The PUC could also create a new reliability price adder for variable generators to capture the cost of backstopping those generators with dispatchable generation. That approach might be more efficient and market-driven than a new ancillary service, but it would still not guarantee that a certain amount of backup power would be procured. At this moment, the ancillary service appears to provide the most direct route to improving the reliability of wind and solar resources at the lowest cost to consumers while minimizing the potential for unforeseen market consequences.

Conclusion

The rapid development of wind and solar generation in Texas is beginning to create serious reliability problems for the Texas electric grid, as evidenced by tight summer conditions since 2018 and most of all by Winter Storm Uri. Wind and solar often produce the least electricity during the periods of highest demand, namely hot summer afternoons and cold winter nights. Given the likelihood of continued federal incentives driving the development of these resources, greater investments in reliability are needed to avoid more problems in the future.

The current scarcity pricing mechanisms in the ERCOT market, most notably the ORDC, are not adequate for ensuring reliability. Prices are too low and volatile during most of the year to support continued investment in thermal generation, and variable generators do not have adequate market incentives to produce when demand is highest. If all the PUC does is raise scarcity prices without changing the current market design, the change will only incentivize more wind and solar builds, which will lead to continued retirements of thermal generation and no improvements in reliability. Texas customers will shoulder the burden of higher scarcity prices and more frequent blackouts.

In contrast, a well-designed firming requirement, as proposed in Gov. Abbott's directives to the PUC, would ensure that variable generators have appropriate financial incentives to optimize reliability, just as dispatchable generators do. This requirement will ensure that Texas consumers will not be forced to pay for a system of subsidized backup generation to support subsidized wind and solar generation, as is happening in California and Europe. Some reliability costs will be passed onto consumers, but generators will be incentivized to meet the reliability standard at the lowest possible cost, which is not happening in the current market environment. This firming requirement will also ensure that wind and solar development does not come at the cost of increasing frequency of shortages and blackouts.

A proper electricity market must be designed around the needs and desires of ratepayers, providing electricity when it is needed at the lowest cost possible. Arguments over what is "fair" for generators miss this point entirely. Competitive wholesale and retail markets can deliver these outcomes, but they can only do so under a system of uniform reliability standards where companies have the proper incentives to maximize the quality of electricity service for ratepayers. The current market in Texas, where most of the reliability and delivery costs are placed on customers, does not accomplish this goal and must be reformed. Texas cannot control the federal incentives and mandates that will distort its markets, but it can ensure that it uses its vast energy resources to provide the lowest cost and most reliable electricity for its people. ✯

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