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RELIABILITY STANDARDS TO REDUCE THE COST OF WIND AND SOLAR VOLATILITY IN TEXAS

WRITTEN BY

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RELIABILITY STANDARDS TO REDUCE THE COST OF WIND AND SOLAR VOLATILITY IN TEXAS

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KEY POINTS

- **The cost of wind and solar** variability to Texas ratepayers is at least $2 billion per year and rising.
- **Because the ERCOT market** design pays volatile wind and solar generators the same market price as dispatchable power plants, it forces Texas ratepayers to overpay for unreliable electricity.
- **In 2023, the Texas Legislature** mandated the creation of a generator reliability standard, but only for new generators, which will have a negligible impact until the next decade.
- **Any reliability standard** should apply to all generators to ensure a level playing field and to maximize benefits to Texas ratepayers.
- **A program that reduces** the market price paid to variable generators will save Texas ratepayers money and encourage the construction of more dispatchable generation.

EXECUTIVE SUMMARY

Previous work by Life:Powered (Reed & Bennett, 2025) established that the costs imposed by the variability of wind and solar generation outweigh the benefits of their low operating costs, and those imposed costs are rising as wind and solar comprise a greater portion of the ERCOT resource mix. Wind and solar generators do not bear these costs, which are instead imputed to ratepayers through higher wholesale electricity prices and higher costs for ancillary services.

The first step to correcting this problem is to ensure the costs of ancillary services are allocated to generators, not just passed directly to ratepayers, according to how much those generators increase the procurement of ancillary services. However, the more important problem is the imbalance created by the single clearing price for energy in ERCOT, which enables wind and solar generators to receive the same price for their output as dispatchable generators despite being more volatile.

In 2023, the 88th Texas Legislature directed the Public Utility Commission of Texas (PUC) to establish a reliability standard for generators that begin operating in ERCOT in 2027 or later (HB 1500, 2023, pp. 22–23). This study confirms that three key changes are needed to that legislation in order to correct the existing imbalances in the ERCOT wholesale electricity market and avoid hitting ratepayers with the significant cost impacts of variable generation.

1. **The reliability standard should be applied to all generators beginning in 2027, not only new generators.** Setting a reliability standard for only new generators impacts a small portion of the market each year, creates an uneven playing field between new and existing generators, does not allow existing generators to receive reliability incentives, and will provide fewer benefits to ratepayers than a uniformly applied standard.

2. **The reliability standard for generators should be based upon the performance of the existing gas, coal, and nuclear fleet.** Ratepayers expect that the reliability of the ERCOT grid should match or exceed the historical reliability provided by gas, coal, and nuclear. Every market participant's generation portfolio should be required to match or exceed that standard to prevent reliability costs from being inequitably distributed to ratepayers.

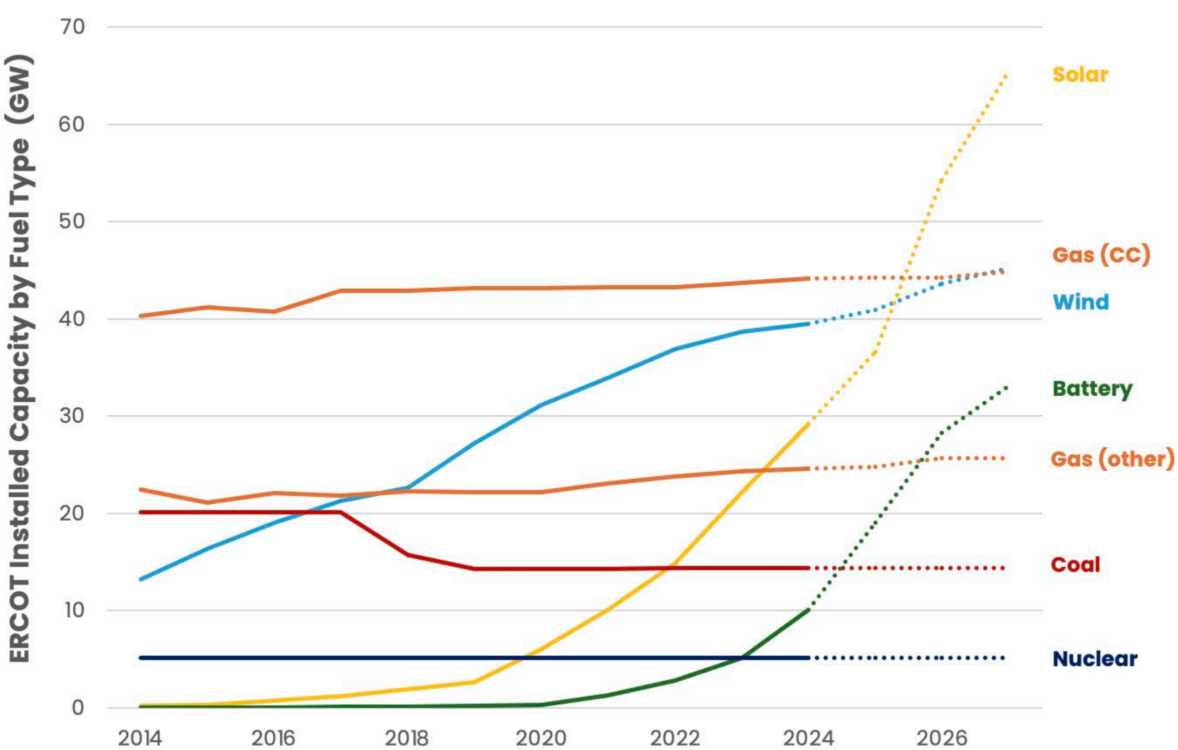
3. **Financial penalties and incentives should match the impact on ratepayers of a resource's performance below or above the reliability standard.** The most effective way to enforce a reliability standard is to reduce the market revenue to generators that do not meet the standard and to redirect the excess revenue to generators that exceed the standard.

INTRODUCTION

Wind and solar generation have grown dramatically in Texas over the past decade, and the state now generates more electricity from wind and solar combined than any other state (EIA, n.d.-a). As shown in **Figure 1**, installed wind capacity grew by 26 GW from 2014 to 2024, and installed solar capacity grew by 29 GW in the same time frame. While wind development has been muted in recent years (primarily due to lack of appropriate sites and adequate transmission), solar installed capacity will surpass wind and likely grow to at least 50 GW by the end of 2026.

Figure 1

Installed Capacity of Wind, Solar, Combined Cycle Gas, Simple Cycle Gas, and Energy Storage From 2014 to 2024 and Forecasted Installations From 2025 to 2027



Note: Data from *Capacity Changes by Fuel Type – December 2024*, Electric Reliability Council of Texas, January 8, 2025 (https://www.ercot.com/files/docs/2025/01/08/capacity-changes-by-fuel-type-charts_december_2024.xlsx). Forecast additions include only projects which have posted financial security with ERCOT.

Energy storage is also on the rise and is forecasted to reach nearly 30 GW of installed capacity by the end of 2026. By contrast, 5.9 GW of gas additions since 2014 have been offset by 5.8 GW of coal retirements, leaving the total capacity of the thermal fleet virtually unchanged over the past decade.

As documented by Life:Powered (Bennett, 2024) and other commentators (Peacock, 2021), federal subsidies are a major driver of the growth of wind and solar in Texas. On average, wind and solar generators nationwide have received $18.58/MWh and $65.71/MWh, respectively, in federal subsidies (Bennett, 2024, p. 14), which are comparable to the average real-time market prices in ERCOT over the past decade (Potomac Economics, 2024, p. 15). Furthermore, those average prices are skewed upward by brief periods of very high prices when wind and solar are generating less electricity. In other words, it is likely that many wind and solar generators in the ERCOT market have earned as much (or more) money in federal subsidies as they have from selling electricity. ERCOT is also a great market for solar and wind developers because of ample wind and solar resources, fast interconnection processes, fully competitive wholesale electricity market, and relatively cheap land and development costs.

Although wind and solar produce low priced electricity for many hours of the year, residential electricity prices continue to rise faster in ERCOT than in surrounding regions (EIA, n.d.-b). A central problem with the ERCOT market is increasing price volatility and ancillary services procurements due to wind and solar variability, which is costing Texas ratepayers at least $2 billion annually (Reed & Bennett, 2025). These costs arise partly in the form of increased use of ancillary services but primarily in the form of higher operating costs for dispatchable power plants and more scarcity pricing and price volatility to ensure resource adequacy. Importantly, ERCOT's market structure ensures that these costs are borne by ratepayers and not by wind and solar generators, which leads to a chronic market imbalance that drives up system costs.

The structure of the ERCOT wholesale market, which uses "energy-only" pricing, is an underappreciated driver, arguably a critical driver, for wind and solar development. Regardless of what market participants bid for their electricity in ERCOT, they are paid the same clearing price for electricity (called the locational marginal price, or LMP) at each point in time. The value of a power plant is not only defined by the electricity it delivers in real-time but also by the electricity it can be counted on to deliver at any point in the future, which is called its capacity value. This fact is why most electricity markets across the world employ a mix of pricing mechanisms to pay for both energy and capacity. The uniform LMP for energy in ERCOT assumes that sufficient capacity will be built over time because the generators that are providing real-time energy have high inherent capacity values. However, this model overvalues generators (like wind and solar) whose output is more uncertain and can lead to a capacity deficit in markets like ERCOT that have large wind and solar penetrations.

There are several possible solutions to this problem. Previous work by Life:Powered considered the creation of a new ancillary service whereby variable generators were required to pay for extra backup power to be available during peak demand periods (Bennett, 2021). Another option (which will be considered in future work) is to require generators that do not meet the reliability standard to bid into a separate market with prices that are capped to reflect the relative value of those generators compared to more reliable generators. One challenge with that option is the complex implementation involved in dividing the real-time market and setting up separate bidding processes, but it could have the benefit of optimizing bidding behavior and dispatch order and mitigating the negative impacts of price volatility on thermal generators.

A third option, which can be implemented by ERCOT immediately, is to cap the payments received by generators that do not meet the standard, either as a fixed price cap for all underperforming generators or as a flexible fee that is adjusted according to the performance of each generator. The proceeds can either be rebated directly to consumers or directed to generators that exceed the performance standard. By stopping the overpayment of variable generators that exists today, consumers will save money and dispatchable generators will be better compensated and with less volatility. This option also aligns with the statutory directive from the 88th Texas Legislature for the PUC to establish a reliability standard for generators that enter service in 2027 or later and to establish financial penalties and incentives for generators that fall short of or exceed the standard (HB 1500, 2023, pp. 22-23).

The key problem with the existing statute is that it only applies to new generators, and **Figure 1** demonstrates why this policy will require many years to produce tangible benefits for Texas ratepayers. Total installed wind and solar capacity in ERCOT is forecast to be approximately 98 GW by the end of 2026, after which generators will be subject to the new reliability standard. The average rate of combined wind and solar additions in 2025 to 2026 is expected to be 15 GW per year. If that rate is continued in 2027 and beyond, the quantity of wind and solar subject to the standard will not exceed the quantity grandfathered in until at least 2033, unless a significant amount of older wind and solar generation is retired during that time.

The excess volatility caused by wind and solar generation is already costing Texas ratepayers upwards of $2 billion annually, and applying a reliability standard only to new generation will not solve the problems created by existing wind and solar. It will also create a two-tiered system, one for new generation and one for old, that will put new, more efficient generation at a disadvantage. The reliability standard enacted by HB 1500, Section 23 must be modified to apply all generators to solve the full set of problems related to wind and solar volatility and to provide meaningful benefits to ratepayers over the next decade. Once that important step is made, the next question is how to set the reliability standard, as well as the financial penalties for failing to meet the standard and the financial incentives for exceeding it, in such a way as to maximize ratepayer benefits.

A RELIABILITY STANDARD TO ADDRESS SEASONAL AND ANNUAL VARIABILITY

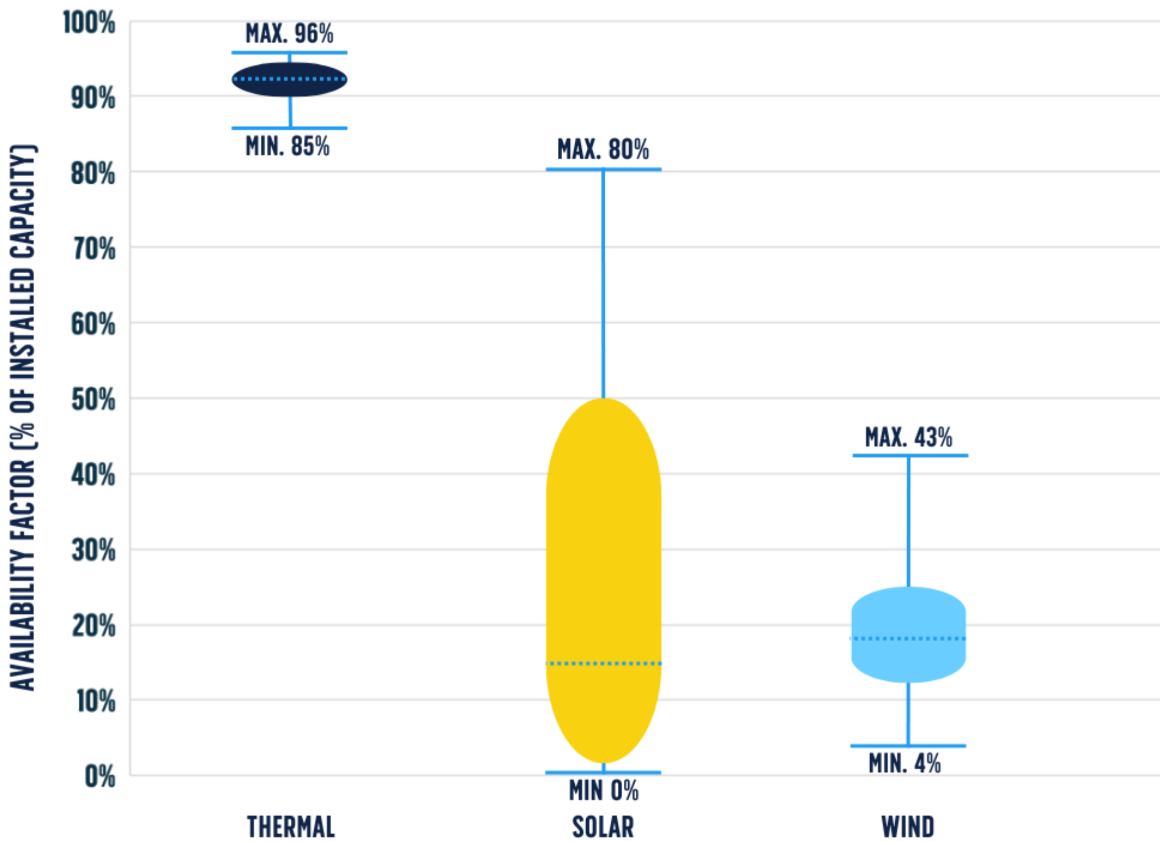
The key metric for setting a reliability standard for generators is their performance during the hours of lowest system reserves and highest prices. Historically, these hours were coincident with the hours of highest demand, but the growth of wind and solar in Texas have caused prices to correlate more with net load, which is demand minus wind and solar output (Potomac Economics, 2024, p. 79). As noted in the first paper in this series, the primary cost imposed by wind and solar generators is the variability in their output during peak net load hours, and any dispatchable generators that are offline during these periods also create a need for high-cost reserve power. Therefore, any reliability standard for generators must focus on their availability during the highest net load hours every year.

One option would be to set the standard such that a generator is penalized if its low-end availability during peak net load hours exceeds the low-end availability of the aggregate thermal fleet. Since the outage rate of the thermal fleet averages about 5% to 10% during peak net load hours, wind and solar generators would need to guarantee 90% to 95% of their expected output during those hours to meet the same standard. **Figure 2** shows the aggregate availability of solar, wind, and thermal generation, as a percentage of total installed capacity, for the highest 100 net load hours in 2024.

The average availability of wind during these hours in 2024 was 18%, and the minimum availability was 4%. Therefore, a reliability standard for wind generators to firm up to 90% of their expected output would require them to ensure firm capacity equal to about 16% of their installed capacity, which would mean an additional procurement of 16% - 4% = 12% of installed capacity. There was 39 GW of wind in ERCOT in 2024, so a 12% requirement would have been 4.5 GW. Using ERCOT's 2024 cost of new entry for gas generation of $140 per kW-year (Rickerson, 2024), this

Figure 2

Maximum Available Output of Wind, Solar, and Thermal Generators in ERCOT During the 100 Highest Net Peak Load Hours, 2024



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) and *Electric Reliability Council of Texas*, Gridstatus.io, n.d. (https://www.gridstatus.io/live/ercot).

procurement would cost $630 million per year. That cost would equate to over 10% of total wind revenue (energy plus production tax credits) in 2023 (Reed & Bennett, 2025). It may be necessary to phase in the requirement over time to allow market participants time to adjust to that large of a change, but it cannot be ignored that the cost of shortages due to low wind output is real and is currently being fully borne by ratepayers.

The distribution of solar availability in **Figure 2** is very wide because net peak load hours in the summer are shifting from the afternoon to the evening as more solar comes online. More net peak load hours are also occurring in the winter, either around 8 AM or 8 PM when there is no solar production at all. This shift was already evident in 2024, where the average output of solar during the highest 100 net peak load hours was only 13% of installed capacity. A major challenge with applying this methodology to solar is that by the time any reliability requirement is put into place, net peak load will occur entirely at hours when average solar production is zero, which means solar would not have to procure any firm capacity.

However, that shift does not mean solar will cease causing any market volatility or imposing any costs on the system. Prices in ERCOT are consistently highest when the sun is rising and setting (Gridstatus.io, n.d.) because those periods require extra ramping from online resources and the use of the highest cost marginal resources, namely peaking gas and batteries. Furthermore, our previous work (Reed & Bennett, 2025) was conclusive that replacing solar with gas did far more to reduce price volatility and overall system costs than replacing wind with gas. Therefore, in addition to an annual standard to account for the uncertainty in net peak load, it is imperative to develop a separate standard to address the costs imposed by the hourly and daily variability of wind and solar.

A RELIABILITY STANDARD TO ADDRESS HOURLY AND DAILY VARIABILITY

The first step to estimating the cost of the hourly and daily variability of wind and solar (hereafter called "real-time variability" since it primarily affects the real-time energy market) is to calculate the overall system variability compared to a system without wind and solar. In other words, the volatility in net demand should be compared to the volatility in overall demand. **Figure 3** shows the load and net load in ERCOT on a high demand day and a low demand day in 2024, with each day exhibiting average wind and solar generation patterns. On the high demand day, wind and solar flattened the demand curve and only marginally increased the overall volatility that day. But on the low demand day, wind and solar turned what was a very stable demand curve and made it much more volatile, with a steep ramp in the late afternoon as the sun went down.

Throughout the entirety of 2024, solar increased system volatility by 28% and wind increased it by 26% (see **Table 1**). When combined, wind and solar increased system volatility by only 30% because some of the volatility of the different resources cancel each other out. While solar generation is more correlated to demand than wind (because wind blows the most at night when demand is low, particularly in the summer), solar increased system variability in 2024 nearly twice as much per MW of installed capacity as wind did. Solar generation not only varies from minimum to maximum output and back every day, but it does so within the span of just a couple hours, putting more strain on balancing resources to match its changes. Therefore, any reliability penalty that accounts for real-time variability will necessarily weigh more heavily on solar than on wind.

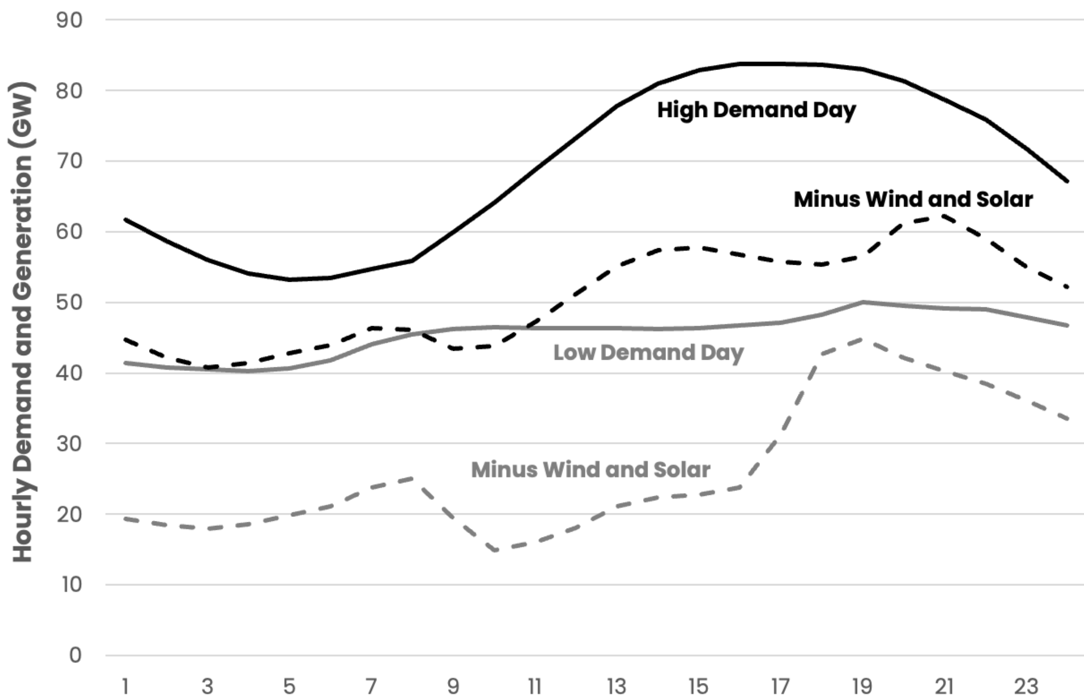
While the contribution of each resource to hourly volatility is easy to calculate, quantifying the impact of additional volatility on wholesale prices is far more challenging. The reliability costs incurred from additional volatility be estimated using the additional procurements of ancillary services to keep the system stable. The PUC determined that 42% of ancillary service procurements in 2023 were caused by wind and solar volatility, at a total cost of $788 million (PUC, 2024, p. 12). However, that cost is still minor compared to the cost of efficiency losses due to ramping and the need to use more higher-cost resources, such as gas turbines and batteries, instead of more efficient combined cycle gas power plants.

The impact of real-time volatility on wholesale prices is difficult to calculate because the total impact of wind and solar volatility in 2023, $2.3 billion (Reed & Bennett, 2025), was primarily a result of a small number of hours where prices were very high due to overall resource scarcity and not due to real-time volatility. The price impacts of low reserves and higher real-time volatility are both mitigated in unison by replacing wind and solar with gas units, and the two effects cannot be easily disaggregated. However, it is possible to model the impact of removing wind and solar on unit efficiencies ("heat rate," in the industry parlance) and on the use of baseload units compared to peaking units. Measuring the total system efficiency and operating costs with and without wind and solar can provide an estimate of the cost of real-time volatility.

Once the cost of real-time volatility is calculated, it could be assigned to each variable generator according to that generator's contribution to system volatility in the same manner used to derive the data in **Table 1**. However, that method is challenged by the fact that not all hours are the same. The efficiency losses due to ramping are much

Figure 3

Comparison of Load and Net Load on August 8, 2024 (High Demand Day) and December 31, 2024 (Low Demand Day)



Note: Hourly demand and generation data used for this table are 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).

Table 1

2023 and 2024 Total Hourly Volatility of the ERCOT Grid Attributed to Demand, Wind, and Solar Volatility, Gigawatt-hours

	2023 Volatility	% Change	2024 Volatility	% Change
Demand	13,281,622		13,219,396	
+ Wind	16,743,412	26%	16,716,395	26%
+ Solar	14,586,290	10%	16,952,599	28%
+ Both	15,544,008	17%	17,199,230	30%

Note: Hourly demand and generation data used for this table are 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).

greater when the ramp rate is high, such as in the winter when the sun is going down at the same time demand is increasing. Future work in this series will analyze how to determine the impact of each variable generator on the operating costs of dispatchable units and develop a method of allocating the cost to each variable unit.

SETTING FINANCIAL PENALTIES AND INCENTIVES TO MEET THE RELIABILITY STANDARD

HB 1500, Section 23 (2023, pp. 22-23) requires the PUC to establish penalties for generators that fail to meet the reliability standard and incentives for generators that exceed the standard. The size of the penalties and incentives, and how they are applied, are critical to the success of the policy. Setting penalties that are too small will fail to induce any changes from generators or to properly compensate ratepayers for the cost of variability. Penalties that are too large could cause a wave of premature retirements or other market distortions that lead to temporary but expensive reliability and resource adequacy problems until the resource mix adjusted to the changes. Phasing in the penalties over a period of a few years could help avoid some of that disruption, but it still must be accounted for.

Our previous work suggested the creation of an ancillary service as a means to both assess penalties to generators that do not meet the reliability standard and to direct money toward resources that can provide backup power for those underperforming resources (Bennett, 2021, pp. 11-13). However, there are two challenges to creating a new ancillary service at this time. First, ERCOT is already adding a new ancillary service, the Dispatchable Reliability Reserve Service (HB 1500, 2023, pp. 20-21), to address the uncertainty in wind and solar generation forecasts. Second, the money for a new ancillary service would only be directed toward the 4.5 GW of units that participated, which is less than 10% of the overall market, and would not go toward units that exceeded the performance standard but were not a part of the new program. Therefore, we believe the PUC's first priority (before adding another ancillary service) should be allocating the cost of existing ancillary services to wind and solar, which is already required by statute but has not yet been done (SB 3, 2021, pp. 19-20).

Another method to assess financial penalties for generators that fail to meet the reliability standard would be to cap the price they receive in the real-time market, ratepayers should not pay high prices for generation that cannot consistently provide power during times of scarcity. This method has twin advantages of simplicity and efficiency, and ERCOT already employs a wholesale market price cap, which was set at $9,000/MWh but was reduced to $5,000/MWh after Winter Storm Uri (PUC, 2021, p. 1). If a generator meets the reliability standard, it will only be subject to the $5,000/MWh cap, but generators that fail to meet the standard will be subject to a lower cap.

One advantage of this method is that it avoids the problem of how to allocate the funds collected from the penalty. Ratepayers simply pay less for underperforming generators, and market forces will dictate that the difference is reallocated through a combination of more revenue for generators that exceed the standard and lower bills for ratepayers. Over time, the market will likely incent generators that meet the standard to produce more electricity and incent the construction of more dispatchable generation, which is the inverse of what has happened to date because of the overvaluing of variable generation in ERCOT. Alternatively, the PUC could dictate that a certain portion of the revenue be allocated to generators that exceed the standard, which ensure that some money is directed toward improving reliability instead of simply hoping that would happen.

Table 2 shows a few possible options for price caps and the modeled impact of those caps on wind and solar revenues in 2023. A $50/MWh cap would cut $110 million, or 11%, of solar revenue and $199 million, or 8%, of wind revenue. A $30/MWh cap would cut 19% of solar revenue and 14% of wind revenue. Given that wind and solar only produced $3.5 billion in total energy revenue, no reasonable price cap or penalty could come close to accounting for the $2.3 billion that wind and solar volatility cost consumers. However, if the penalty incents additional dispatchable generation that reduces the size and frequency of price spikes, the benefits to consumers could far exceed the direct rebate from the penalty.

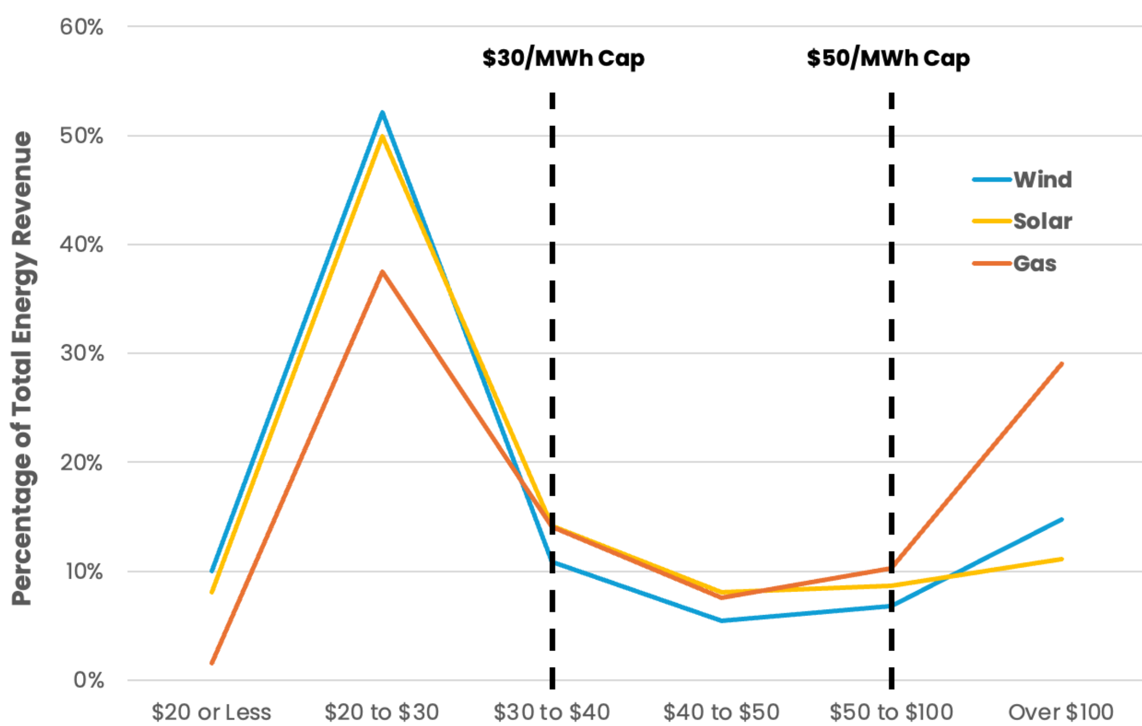
Table 2
2023 Energy Revenue Impact of $50/MWh and $30/MWh Revenue Caps on Wind and Solar Generators, Millions of Dollars

	2023 Revenue	$50/MWh Cap	Difference	$30/MWh Cap	Difference
Solar	1,017	907	110	827	190
Wind	2,476	2,278	199	2,133	343

Note: Data from Reed & Bennett, *The Cost of Wind and Solar Variability to Texas Ratepayers*, Texas Public Policy Foundation, 2025 (https://lifepowered.org/wp-content/uploads/2025/02/2025-02-LP-Cost-of-Wind-and-Solar-ReedBennett.pdf).

The UPlan model used for this work (LCG Consulting, 2025) underestimated total real-time market revenues in 2023 by about $12 billion (Reed & Bennett, 2025), or about 40%, so the true revenue impact would have been higher than shown here. However, as shown in **Figure 4**, wind and solar generated only about 20% of their revenue from periods with prices above $50/MWh (consistent with high prices being correlated with low wind and solar output), whereas gas generated nearly 40% of its total revenue from these periods. Therefore, **Table 2** is still a reasonable estimate of the annual revenue impact of these price caps on wind and solar, especially in a more average year without so many price spikes.

Figure 4
Percentage of 2023 Energy Revenue for Wind, Solar, and Natural Gas by Real-Time Energy Price



Note: Data from Reed & Bennett, *The Cost of Wind and Solar Variability to Texas Ratepayers*, Texas Public Policy Foundation, 2025 (https://lifepowered.org/wp-content/uploads/2025/02/2025-02-LP-Cost-of-Wind-and-Solar-ReedBennett.pdf).

The primary challenge with using price caps is that they do not account for the relative performance of individual generators. Generators that are close to meeting the reliability standard are subject to the same price caps as generators that fall well short of it. A staggered price cap might solve some of this problem, but ideally, each generator should be assessed on how it performs and not put into a one-size-fits-all box. Also, because wind and solar derive 80% of their revenue from electricity priced below $50/MWh, any price cap below that amount, whether staggered or fixed, will be subject to large variations depending on market behavior in any given year.

A more flexible method would be to assess each underperforming generator a fee based on how far short of the reliability standard. As with the price caps, these fees can be assessed within the market context by eliminating a percentage of revenue from underperforming generators and allowing the market to determine where the difference goes. Alternatively, the proceeds can be given to generators that exceed the standard, again allocated by increasing the revenue they receive. The best measure of performance for dispatchable units is the outage rate, which is the inverse of the availability rate shown in **Figure 2**. The less time that a unit is out for planned and unplanned maintenance, the more time it is available to support demand based on market needs. An additional incentive to remain online will help support the economics of all dispatchable generators and encourage those generators to improve their performance.

CONCLUSION

Following Winter Storm Uri in 2021, the Texas Legislature, the PUC, and ERCOT made numerous changes to improve the reliability of the ERCOT grid, including establishing weather resiliency standards, improving emergency operations, and reforming ancillary service procurements (Bennett et al., 2022). However, despite a clear directive from Governor Greg Abbott (Letter from Gov. Greg Abbott to PUC, 2021), market reforms to equitably allocate the costs being imposed by variable generators—primarily wind and solar—have not been accomplished yet.

The first key reform is the cost allocation of ancillary services, which is required by statute (SB 3, 2021, pp. 19-20) but is not being done, with ratepayers currently bearing 100% of those costs. Second, as described in this paper, the Texas Legislature must direct the PUC to create a reliability standard for all generators, not just new generators beginning in 2027 as is currently required (HB 1500, 2023, pp. 22-23). The standard should be enforced through financial penalties and incentives that reduce the market revenue to generators that do not meet the standard and redirect the excess revenue to generators that exceed the standard. A uniform reliability standard for all generators is essential to correct the existing imbalances in the ERCOT wholesale electricity market and avoid future reliability challenges and electricity rate increases due to the rising costs of variable generation. ■

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Michael has BS and MS in Chemical Engineering from West Virginia University. He has worked for many entities in the energy sector including two national laboratories (NETL, INL), General Motors, and most recently at the Lower Colorado River Authority. He is presently completing his dissertation for a PhD in Natural Resource Economics from West Virginia and expects to graduate by the end of 2025. The dissertation is based on his high-fidelity model of the New York Independent System Operator (NYISO) electricity generation and delivery system. The research is a technical and economic impact assessment of scenarios that meet the New York State law requiring 100% carbon free electricity in 2040.

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