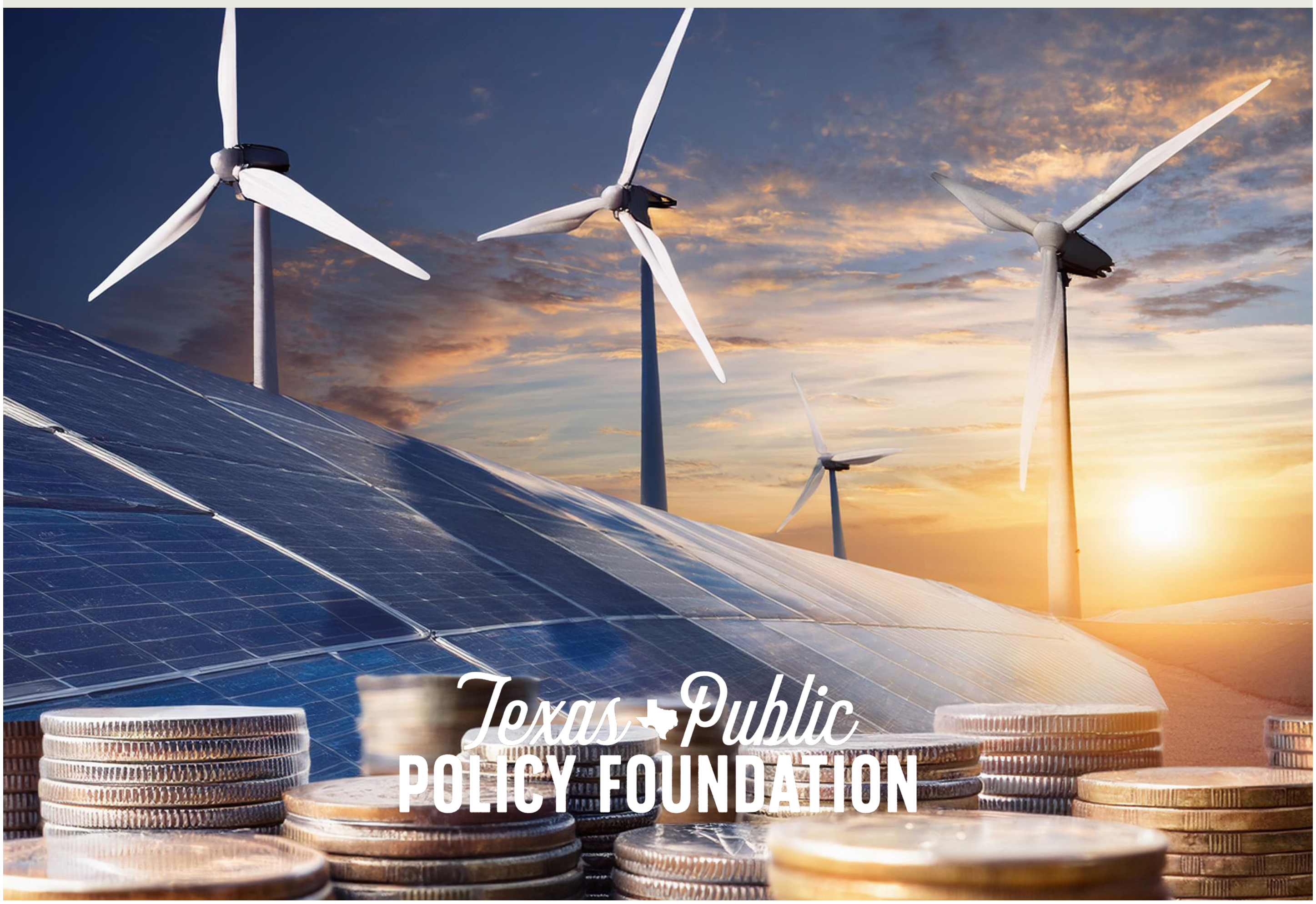
LIFE:POWERED

THE COST OF WIND AND SOLAR VARIABILITY TO TEXAS RATEPAYERS

WRITTEN BY
Michael Reed and Brent Bennett, Ph.D.
February 2025



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KEY POINTS

- **The estimated cost** of wind and solar variability in ERCOT, in the form of higher prices for energy and ancillary services, was $2.3 billion in 2023.
- **Replacing wind and solar** with gas generation not only reduced overall prices but also price volatility, reducing the maximum price from the $5,000 market cap to less than $500 and eliminating negative pricing.
- **The Public Utility Commission** of Texas estimates that wind and solar contributed to 42% of ancillary services procurements in 2023 at a cost of $788 million.
- **Texas law requires** that the cost of ancillary services be allocated on a "cost-causation" basis, yet the full cost is passed to ratepayers.

EXECUTIVE SUMMARY

Many Texans believe that adding more wind and solar to the Texas electric grid is the lowest-cost option for meeting the state's growing electricity demand. This misguided belief is bolstered by studies that show the cost of generating electricity from wind and solar is lower than from any other resource (Lazard, 2024). Despite the high capital costs of wind and solar generators, their zero fuel costs and low operating costs are claimed to result in lower average costs over a 20+ year period. Other studies claim that wind and solar have saved Texas consumers money over the past several years, compared to a hypothetical situation in which natural gas generators had been built instead of wind and solar (Rhodes, 2024).

Despite these claims of cost savings, average retail electricity prices for residential consumers in Texas are on the rise, increasing almost 20% over the past three years (EIA, n.d.-a). Part of this increase is due to increases in the cost of electricity delivery and overall inflation in the electricity sector. However, wholesale electricity prices in Texas were 38% higher in 2023 compared to 2019 despite natural gas prices being near historic lows in 2023 (Potomac Economics, 2024, p. 15). This study focuses on the causes of higher prices in the Electric Reliability Council of Texas (ERCOT) wholesale market and proposes some solutions for mitigating future cost increases.

The output of wind and solar generators in the ERCOT region, which covers about 90% of Texas' population, is 5 to 10 times more variable in aggregate than gas, coal, and nuclear generators during peak-demand periods (Gridstatus.io, n.d.). This study posits that the increasing variability of Texas' electricity supply, coupled with expensive administrative actions by ERCOT to manage that variability, is offsetting the lower operating costs of wind and solar.

The cost of this variability—manifested primarily in the need for dispatchable power plants to ramp up and down more frequently and dramatically—added up to $2.3 billion in 2023 and is expected to rise as more wind and solar is added to the ERCOT grid.

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To date, no study has been undertaken to assess these system-level costs or to consider how they might be allocated to wind and solar generators. On July 6, 2021, Governor Greg Abbott issued a letter to the Public Utility Commission of Texas (PUC) that included a directive to "allocate reliability costs to resources that cannot guarantee their own availability, such as wind or solar power" (Letter from Gov. Greg Abbott to PUC, 2021). In 2023, the 88th Texas Legislature required the PUC to publish an annual report each December estimating the annual costs "associated with backing up dispatchable and non-dispatchable electric generation facilities" and to complete a study on the impact of allocating the costs of ancillary and reliability services by December 1, 2026 (HB 1500, 2023, pp. 21, 24). This paper is meant to be a clarion call for these studies to be expedited and for the PUC to implement policy changes to mitigate the impacts of these costs on Texas consumers.

INTRODUCTION

Wind and solar have been the fastest-growing sources of electricity generation in the Electric Reliability Council of Texas (ERCOT) market over the past decade, primarily because of federal and state subsidies (Peacock, 2021; Bennett, 2024), ample wind and solar resources, and the fact that the ERCOT market design overvalues unreliable generation. Between 2018 and 2024, 17 GW of wind and 25 GW of solar were added to the ERCOT grid, while only 3.3 GW of gas was added (ERCOT, 2024a). ERCOT's more conservative forecast predicts that an additional 3.3 GW of wind and 28 GW of solar will be added in the next three years, along with 16 GW of energy storage. Therefore, the proportion of electricity generation in ERCOT coming from wind and solar, which was roughly 30% in 2023 (ERCOT, 2024b), will likely exceed 40% by the end of 2027, depending on how rapidly consumer demand grows.

Despite having very high capital costs, wind and solar are often touted as being the "cheapest" forms of electricity generation—that is, having the lowest levelized cost of generating electricity (Lazard, 2024)— because their fuel (wind and sun) are free and their operating and maintenance costs are very low. Several published studies claim that wind and solar save Texans billions of dollars per year, as compared to using new gas generation (Rhodes, 2024). However, to date, no study has been done using a model that fully mimics the nodal pricing and geography of the ERCOT market and that optimizes the replacement of wind and solar with gas to study the impact of the different resource mixes.

Contrary to what these studies claim, empirical evidence suggests that wind and solar are driving up total system costs in ERCOT. Residential electricity prices in Texas have increased almost 20% over the past three years (EIA, n.d.-a) and are now higher than all of the states surrounding Texas, including states to the east of Texas that are managed by monopoly utilities and that have very little wind and solar. Industrial electricity prices in Texas have remained steadier and are comparable to prices in neighboring states (EIA, n.d.-a), but industrial consumers should expect their prices to rise soon, given that wholesale electricity prices in Texas were 38% higher in 2023 than in 2019, despite natural gas prices being near historic lows in 2023 (Potomac Economics, 2024, p. 15).

It should be unsettling to policymakers that the ERCOT market, in an era of historically low natural gas prices, offers no price advantage over its neighbors while suffering from lower reliability and more uncertainty concerning its future generation mix and prices. With demand growing quickly in Texas and forecasted to grow even more dramatically with the addition of new computing loads, vast amounts of new generation will need to be added to the ERCOT grid over the next decade (Morris and Lamb, 2024). There is no indication that the trend of rising prices will abate soon, and the trend could worsen if gas prices increase. It is incumbent upon Texas policymakers to ensure this massive grid expansion benefits rather than burdens Texas ratepayers.

The goal of this study and subsequent studies in this series is to ascertain why prices are rising so quickly in Texas despite its lauded competitive electricity market, and to point toward policy solutions for improving the balance of cost and reliability, particularly for residential and small commercial consumers. A future study will address transmission costs, which have more than doubled over the past decade (ERCOT, 2023a, p. 8) and are expected to rise even further due to inflationary pressures and more than $13 billion in transmission upgrades being considered for West Texas (Hobbs, 2024, p. xi). This study will address costs in the wholesale market, in particular the costs being imposed on the system by the high variability of wind and solar generation.

THE RELATIVE VARIABILITY OF GENERATION RESOURCES IN ERCOT

Although wind and solar can generate electricity at a low cost, their inability to ramp their output up and down to respond to changes in demand—a trait that is often called dispatchability—creates significant operational problems and extra costs for the ERCOT market. Furthermore, their output often changes in a manner opposite to demand patterns, putting extra strain on dispatchable resources to ramp up and down. This paper will use the term "variable" interchangeably with "wind and solar"—even though all generation resources are variable to some degree—and "dispatchable" or "thermal" to describe gas, coal, and nuclear resources. Any source of variability creates problems for the grid, including sudden outages of thermal power plants and changes in demand, but the variability of wind and solar output at any point in time is 5 to 10 times greater than the average variability of thermal resources (see **Figure 1,** next page).

Because of the explosion of wind and solar in ERCOT over the past decade, wind and solar are now such a large part of the ERCOT grid that their aggregate output can vary as much or more than demand on a daily and seasonal basis. Therefore, wind and solar output often dictate electricity prices more than demand, and wholesale electricity prices are increasingly reaching peaks not when demand is highest but when wind and solar output are low. Scarcity pricing and tight grid conditions are now driven by net load (or total demand minus wind and solar output), which is equal to the amount of power that must be delivered by dispatchable generators (Potomac Economics, 2024, p. v).

The full distribution of aggregate solar, wind, and thermal generation during the highest 20 summer and winter net load hours in each year from 2021 to 2024 is shown in **Figure 1** as a percentage of installed capacity. Wind output varies by roughly 10% above or below its expected output of 15% of installed capacity. Winter peaks generally occur around 8 AM and 8 PM, when solar output is zero or close to zero. Net peak load in the summer is increasingly shifting from the afternoon to the evening hours as more solar comes online, which is why the distribution for solar is so wide in **Figure 1b**. However, as solar generation increases in ERCOT, net peak should shift entirely to the evening hours and the solar distribution in **Figure 1b** should look more like that in **Figure 1a**. The availability of thermal generation falls within a relatively narrow distribution between 88% and 94% in the winter and 91% and 95% in the summer, which is a variance of only 2-3%.

Figure 1a: *Maximum Available Output of Wind, Solar, and Thermal Generators in ERCOT during Winter Net Peak Load Hours, 2022-2024*

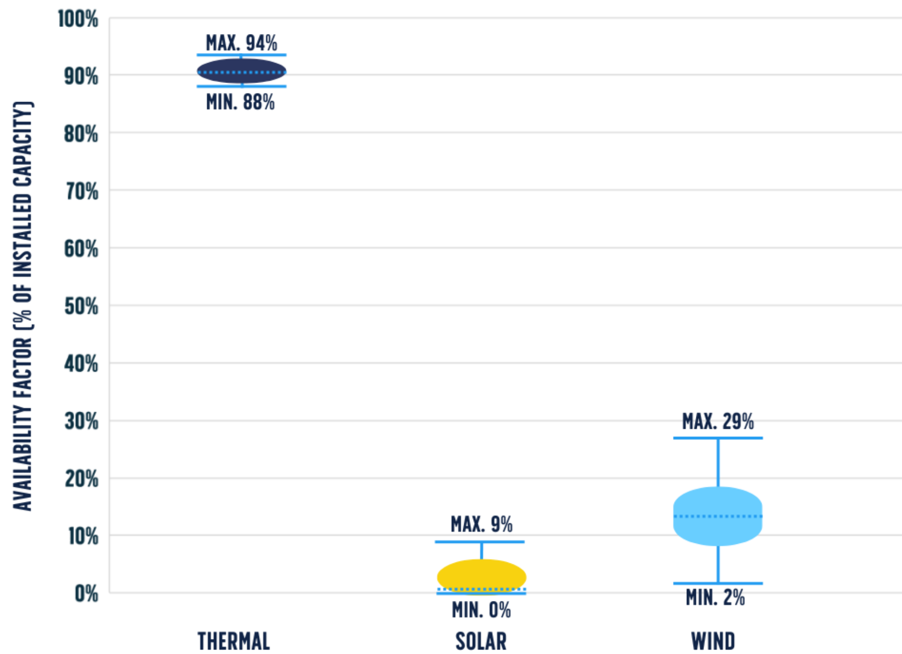
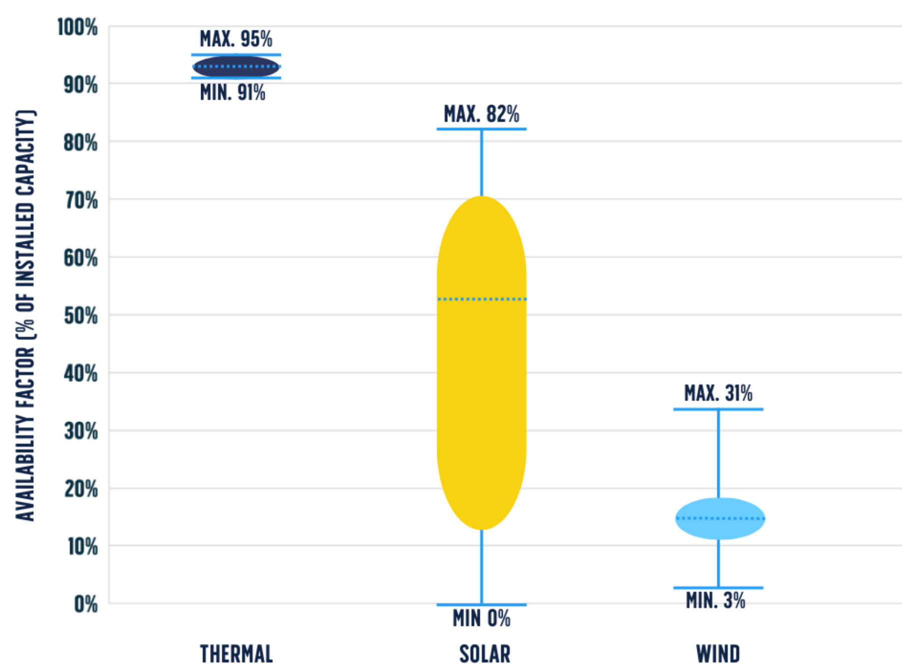


Figure 1b: *Maximum Available Output of Wind, Solar, and Thermal Generators in ERCOT during Summer Net Peak Load Hours, 2021-2024*



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

Winter peak demand is expected to grow about 5 GW annually for the rest of this decade, a total of about 30% over 2024 demand, under conservative estimates of computing load growth (ERCOT, 2024c, p. 26). Summer demand during the crucial 8-9 PM hour will grow by a similar amount (pp. 10, 26). Because solar is the primary resource in the interconnection queue, and solar will contribute little to nothing during these key summer and winter hours, events where peak net load exceeds 70 GW will become increasingly likely in both the summer and the winter. Therefore, absent significant growth of dispatchable capacity and energy storage, there will be a higher risk of even minor deviations from normal weather (like what was seen in 2023), leading to high prices and outages.

The cost of wind and solar variability manifests primarily in two forms. First is the cost of managing the minute-by-minute changes in wind and solar output. Similar to how a car in stop-and-go traffic is less efficient than a car moving at a constant speed, power plants are less efficient when ramping up and down to balance fluctuations in wind and solar output. Second is the cost of ensuring enough resources (both generation and energy storage) are available when wind and solar production is low for long periods. This is akin to a situation where a person has a cheap car that only works some of the time, requiring the person to call an Uber when their car will not start. At what point is the "cheap" car more expensive to own and operate than a car that works all the time?

In essence, this study and subsequent studies will aim to assess the total system costs of wind and solar in ERCOT, balancing those costs against the benefit of their low operating costs in order to determine their total impact on electricity prices in ERCOT. This work can be viewed as complementary to the study the Public Utility Commission of Texas is required to do each year to estimate the annual costs "associated with backing up dispatchable and non-dispatchable electric generation facilities" (Texas Utilities Code § 39.1591). The first complete version of that study was published on November 29, 2024 (PUC, 2024), and the findings of that study are helpful for benchmarking some aspects of the modeling effort described in this study.

MODELING THE IMPACT OF WIND AND SOLAR ON THE ERCOT WHOLESALE MARKET IN 2023

Unbundling the impact of wind and solar on electricity consumers in ERCOT is a complex, multitiered process, consisting primarily of impacts on wholesale energy prices, ancillary services, and transmission and interconnection costs. For the year 2023, the latter two items are adequately covered by the aforementioned report from the PUC (PUC, 2024). However, discerning the impact of wind and solar on wholesale energy costs requires additional modeling that involves comparing the existing system with a hypothetical system that replaces wind and solar with natural gas generation.

To construct our system model, we used the UPlan Network Power Model (UPlan-NPM) from LCG Consulting (LCG, n.d.). UPlan-NPM is a combination of physical and economic models that mimics the geography of the ERCOT market—location, size, and type of generators, location of load, and how they are connected through transmission lines—and coordinates the dispatch of each generator to meet demand. Concurrently, it determines energy prices based on the marginal cost of each generator to enter the market, setting the market price at each node in the system based on the highest cost generator that dispatches to serve demand at that location.

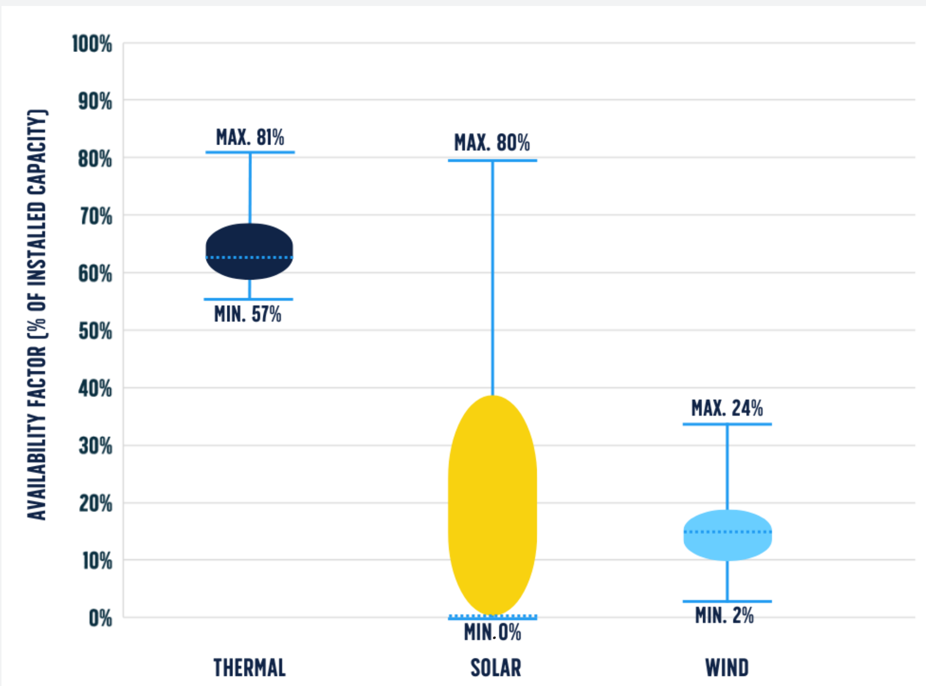
UPlan-NPM is primarily used in a prospective manner for market forecasting, energy trading, and resource planning, but it can also be used retrospectively to model market outcomes of prior years under different resource mixes. We used UPlan-NPM to simulate the year 2023 with the actual generation mix that was in place (the base case) and to compare that control scenario to hypothetical scenarios without solar, without wind, and without

The Cost of Wind and Solar Underperformance During Winter Storm Uri

It is important to note that a major limitation of this study is that it uses only one year of data: 2023. That year featured a hotter-than-normal summer and a significant winter storm, but it did not have the rolling outages of February 2011 or the record heat during the 2011 summer. And, of course, the storm was not nearly as impactful as Winter Storm Uri in February 2021. While it would be imprudent to consider a 1-in-100 storm like Uri in any baseline analysis of the ERCOT grid, it is instructive to consider how increasing reliance on wind and solar increases the risk that deviations from normal weather will cause abnormally high prices and outages.

Figure 2 shows the availability of wind and solar compared to thermal generators during the entirety of the four days of Winter Storm Uri when outages were occurring. While the thermal fleet experienced an unprecedented level of outages, only operating between 60% and 70% of installed capacity compared to its >90% average during summer and winter peak hours, the wind and solar fleet operated at below 20% of its combined capacity the entire time. Combined wind and solar generation never exceeded 10 GW during those four days (EIA, n.d.-b).

Figure 2: *Output of Wind, Solar, and Thermal Generators in ERCOT from February 15, 2021, to February 18, 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/ERCO) and *Live - Electric Reliability Council of Texas*, Gridstatus.io, n.d. (https://www.gridstatus.io/live/ercot).

The cost of underperformance during Winter Storm Uri was extreme. Total energy revenue in ERCOT in 2021 was $66 billion (Potomac Economics, 2022, p. A-11), compared to $29 billion in 2023 (Potomac Economics, 2024, p. A-27), so it could be said that the cost impact of this single storm was greater than a full year's worth of energy revenue. And, as documented in our previous report on the storm (Bennett et al., 2022), a significant factor in the severity of the outages was years of overinvestment in wind and solar and underinvestment in thermal capacity and in the resiliency of the thermal fleet.

Table 1

Installed Capacity by Fuel for the 2023 Base Case, No Solar, No Wind, and No Wind or Solar Scenarios, in Megawatts (MW)

	Base Case	No Solar	No Wind	No Wind or Solar
Natural Gas	57,975	73,089	68.697	85,167
Coal	13,708	13,708	13,708	13,708
Nuclear	5,164	5,164	5,164	5,164
Wind	38,681	38,681	0	0
Solar	23,961	0	23,961	0
Other	1,974	1,974	1,974	1,974
Total	141,463	132,616	113,504	106,013

Note: Values represent the total capacity in the market during at least some portion of the year. A significant amount of solar (over 9 GW) and wind (2 GW) was added over the course of the year, so those units were not in operation for the entire year. A few gas units were added and retired as well.

both. Energy storage was also removed in the cases where solar was removed and where both wind and solar were removed.

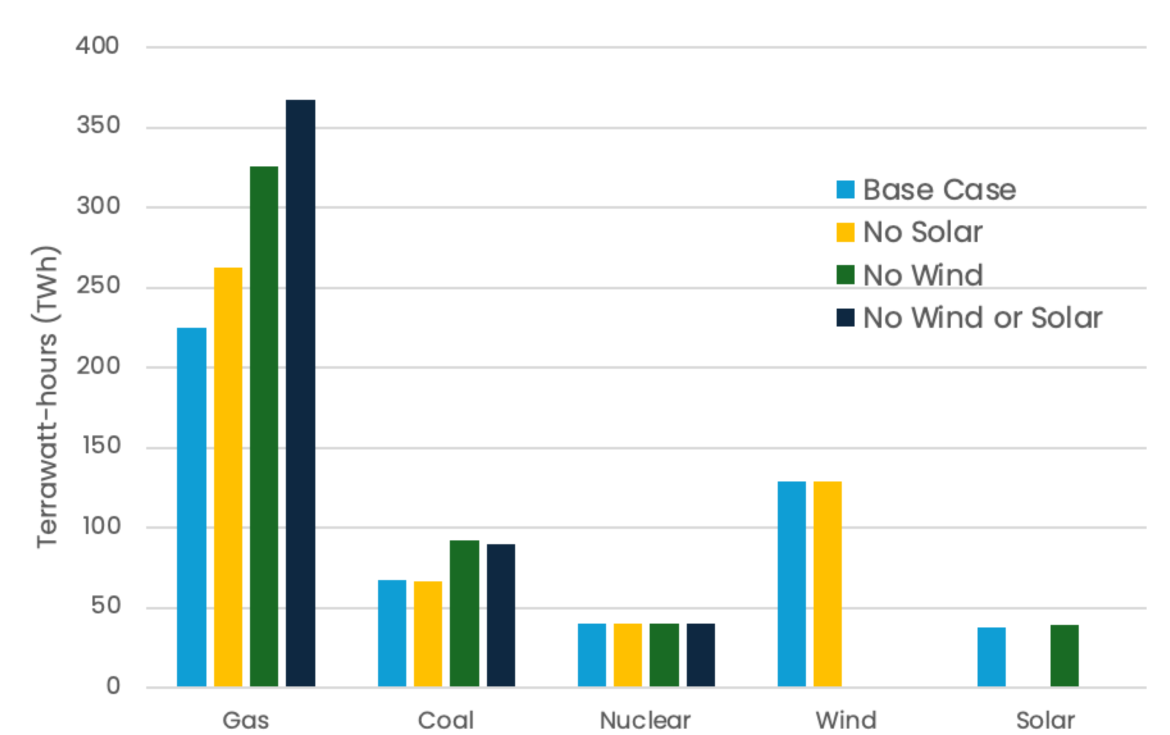
Table 1 shows the 2023 installed capacities of different resources in ERCOT in the four modeled cases. In each of those cases, the generation that was removed was replaced with enough natural gas generation to ensure that demand was met at each system node. An important caveat is that the model requires more gas generation to be added to meet demand at each point in the system than would be needed in reality.[1] The extra generation ensures that there is no artificial scarcity in any given region, which would lead to localized price spikes, due to generators that are not optimally placed. In addition, the replacement gas generation is needed to ensure that ancillary services that were provided by wind/solar/storage in the base case are covered by appropriate gas units in the alternate cases. The summer reserve margin (reserve margin = available supply/peak demand - 1) in the no wind and solar case is about 24%, whereas the reserve margin in ERCOT before the integration of significant amounts of wind and solar typically ranged from 10 to 20% (ERCOT, 2011, p. 7).

Figure 3 shows the generation by fuel for each of the four scenarios in **Table 1**. Net generation over the course of the year must be the same in every scenario since demand is always the same, but the mix of fuels changes as wind and solar are taken out. Nuclear is always a baseload (24/7) resource, so its generation does not change across scenarios. Coal generation does not change much when solar is taken out because demand is typically higher during the day when solar is generating, so solar is replacing peaking gas more than baseload coal. However, coal generation increases 33% when wind is taken out because the wind tends to blow more at night and during the shoulder seasons when demand is low, pushing out not just marginal gas generation but also coal. Finally, gas increases the most—63% from the base case to the no wind or solar case—because it is the marginal generation resource and because we chose to replace the wind and solar capacity with extra gas capacity and not any other resource.

1 The need to add excess generation to resolve the model does not materially affect the results presented in this paper because the bidding behavior in the model is fixed regardless of how many units are in the system. Unused units are simply not dispatched, and market prices are calculated as if the extra generation is not there. However, by adding enough generation to avoid shortages and emergency conditions across the whole system, we could be underestimating the degree to which the real market would allow price spikes and shortages during a hot summer like 2023. That means the market without wind and solar could have more volatility in reality than in the model. However, since the model understates the total cost of market volatility by $12 billion, we believe our estimate of $2.3 billion for the cost of wind and solar volatility is still conservative.

Figure 3

2023 Annual Generation by Fuel for the Four Scenarios in Table 1, in Terawatt-hours (TWh)



The annual capacity factor for a given generator is the ratio of that generator's output compared to its theoretical maximum output over the course of a year. The greater a generator's capacity factor, the more efficiently it operates and the more opportunity it has to generate revenue and turn a profit. The capacity factor for nuclear remains fixed because nuclear power plants do not ramp up and down and always bid low enough to ensure their power is dispatched, even if the settlement price is below their operating costs. Nuclear power plants only go offline to perform maintenance and to refuel. Wind and solar are also unchanged across scenarios (unless they are removed) because those units are bidding the lowest prices and are always dispatched first. Their output is entirely determined by the weather and how much they go offline for maintenance, and both of those factors are uniform across all the scenarios.

Table 2

Annual Capacity Factor by Fuel for the 2023 Base Case, No Solar, No Wind, and No Wind or Solar Scenarios

	Base Case	No Solar	No Wind	No Wind or Solar
Natural Gas	44%	41%	54%	49%
Coal	56%	55%	77%	75%
Nuclear	89%	89%	89%	89%
Wind	39%	39%	0%	0%
Solar	25%	0%	26%	0%
Other	23%	23%	26%	26%

Note: Capacity factors were calculated only based on units that were in commercial operation for the entire year, excluding units that were added during the year.

Model Prices Compared to Actual Prices in 2023

The UPlan modeling environment functions by trying to mimic the behavior, both physical and economic, of generators in the ERCOT real-time market. A key limitation of the model is its ability to fully capture brief price spikes, which were, unfortunately for Texas consumers and for the model used for this paper, a frequent occurrence in 2023. Whereas the independent market monitor (IMM) reported that real-time energy costs were nearly $29 billion in 2023 (Potomac Economics, 2024, p. A-27), the base case UPlan model, which is supposed to replicate the actual market outcomes, reports only about $17 billion in total energy costs (see **Figure 4**).

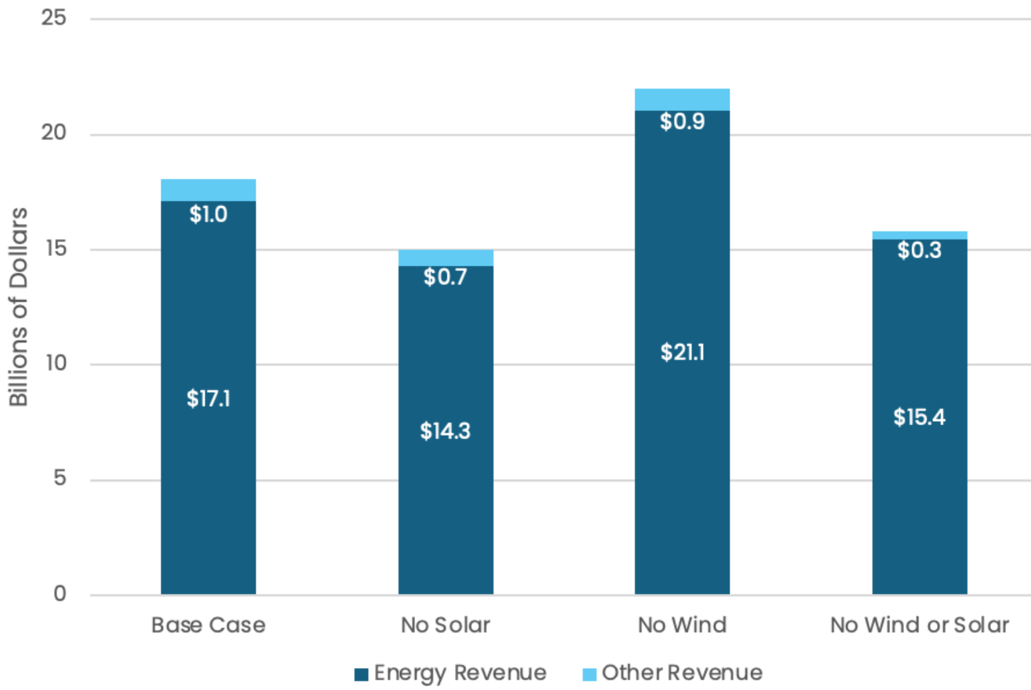
The IMM calculated that price spikes accounted for 46% of the average total cost of energy in the real-time market in 2023, or about $13.3 billion (Potomac Economics, 2024, p. 14). It is not coincidental that the difference between the modeled market revenue and the actual reported revenue is $12 billion; the model failed to capture most of the price spikes, especially during the summer. Furthermore, the reason that replacing wind and solar with natural gas achieved a reduction in cost was by suppressing the remaining price spikes and dramatically reducing price volatility (see **Table 4**). Any other means of reducing market volatility, including by adjusting demand, could have achieved a similar outcome.

The purpose of this paper is not to elaborate on the optimal policies to reduce market volatility but rather to demonstrate that the high variability of wind and solar generation is causing higher prices than would exist in a market that was fully supplied with dispatchable generation. Because the actual costs in 2023 were $12 billion higher than what the model produced, the real cost of wind and solar volatility in 2023 is probably much higher than the $2.3 billion reported here. By the same token, while this cost estimate is conservative for 2023, it probably better represents the impact of wind and solar volatility in a more average year. Despite the model's limitations, the results are conclusive that reducing the impacts of wind and solar volatility should be a paramount goal for Texas policymakers.

Fortunately, Texas ratepayers will not bear all these costs directly, at least not for now. The IMM estimated that 82% of the energy sold in ERCOT in 2023 was hedged (Potomac Economics, 2024, p. 22), which means that consumers were only directly exposed to the remaining 18% of real-time energy costs. Other entities—including retail electric providers, generators, and financial intermediaries—bore the remainder of the costs, which are eventually passed down to ratepayers through the complex workings of innumerable financial transactions among market participants. While these transactions will not prevent ratepayers from avoiding these costs, they perform the vital function of keeping ratepayer bills steady despite the immense volatility of the real-time market.

As noted above, coal sees a large uptick in generation when wind is removed, and therefore its capacity factor increases from 56% in the base case to 77% in the no wind scenario. But since removing solar does not impact total coal generation, its capacity factor remains almost unchanged in the no solar scenario. The capacity factor for natural gas does not change from the base case to the no wind and solar case because of the significant amount of extra gas generation that had to be added to resolve the model. In reality, the 63% increase in gas generation in the no wind and solar case relative to the base case would likely result in higher capacity factors for gas units, particularly combined cycle units that are designed to run continuously.

Figure 4
2023 Revenue from Electricity Sales and Other Sources, in Billions of Dollars



Note: These revenue figures exclude the production tax credit for wind. See the sidebar below for further explanation of how the model treats the production tax credit.

IMPACT OF VARYING RESOURCE MIXES ON ELECTRICITY PRICES IN ERCOT USING THE 2023 MODEL

While there are many more aspects of the model construction that could be discussed here, the most important information for policymakers is how the changes in the generation mix (discussed in the prior section) impact market revenues and costs to consumers. Therefore, we have reserved the rest of the methodology discussion for a separate document and will proceed to discussing the model results. The market revenues that result from each of the four scenarios under study are shown in **Figure 4**. The bars on the bottom represent the total revenue from electricity sales, and the smaller bars on top represent other sources of revenue, which include ancillary services, congestion rent, and anything else not related to energy sales.

In total, the base case shows $18.1 billion in revenue compared to $15.8 billion2 in the case without wind and solar. Therefore, the existing resource mix in ERCOT cost $2.3 billion more to operate in 2023 than a hypothetical resource mix that replaced wind and solar with natural gas. Starting with the "No Wind and Solar" column and moving from right to left in **Figure 4** shows the separate impacts of wind and solar. Notice that the addition of solar without wind increases total revenue by $6.1 billion (compare the "No Wind and Solar" column to the "No Wind" column), indicating that solar is the primary driver of higher wholesale energy prices. If only wind is added (compare the "No Wind and Solar" column to the "No Solar" column), energy market revenue falls by $1.1 billion, indicating the presence of wind in the market results in lower energy costs. By the same token, the energy revenues in the base case are $3.9 billion

2 Rounding causes the two pieces to add up to $15.8 billion, even though each piece rounds down to $15.4 billion and $0.3 billion.

Table 3
Average Real-Time Energy Prices and Natural Gas Prices in the ERCOT Region: 2015 to 2023

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy Prices ($/MWh)									
ERCOT	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$74.92**	**$65.13**
Houston	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$81.07	$64.72
North	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$75.52	$68.55
South	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$72.96	$63.34
West	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$64.53	$61.62
Natural Gas Prices ($/MMBtu)									
ERCOT	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$5.84	$2.22

Note: Data from *2023 State of the Market Report for the ERCOT Electricity Markets*, Potomac Economics, 2024 (https://www.potomaceconomics.com/wp-content/uploads/2024/05/2023-State-of-the-Market-Report_Final_060624.pdf).

lower than in the no wind case, which means wind significantly mitigates the negative impact of solar.

These results comport well with the observed real-time energy prices in ERCOT over the past decade (**Table 3**). In the five years prior to the large expansion of solar that began in 2020, significant amounts of wind generation were added, but real-time prices were relatively steady, averaging about $32/MWh and never rising above $50/MWh. Extremely low demand and low natural gas prices in 2020 drove down prices that year, and then Winter Storm Uri led to the massive price spike in 2021. Since that time, after solar became a major factor in the market, electricity prices have stabilized above $50/MWh, despite natural gas prices returning to their pre-2020 levels. Overall inflation and ERCOT's conservative operating posture since 2021 are playing a role in this increase, as documented by the independent market monitor (Potomac Economics, 2024), yet our data indicates that solar is a significant contributor to the price increase over the past few years.

Although the model shows that wind had the effect of reducing energy revenues in 2023, it is not our conclusion that wind is reducing the total cost of electricity to consumers in ERCOT or that additional wind generation will drive costs lower in the future. Solar and wind both reduce the revenues for base-load coal, gas, and nuclear, resulting in a long-term shortage of dispatchable resources and more volatility in the system. The cost of that capacity deficit is manifested in more frequent scarcity conditions, which was a major driver of higher costs in 2023. Because 2023 was heavily defined by price spikes due to low reserve margins during the late summer hours, replacing solar with sufficient gas to cover demand during those hours eliminated the price spikes. However, in reality, wind volatility and many other factors are also responsible for those tight periods, and the long-term effects of these factors on reserve capacity cannot be captured in a model with only a single year of data. Future work will be needed to assess these multi-year impacts more precisely.

In addition to lowering overall electricity prices, a significant impact of eliminating wind and solar is a reduction in price volatility. As shown in **Table 4**, while the mean price is reduced only slightly (which a reflection of lower overall prices), the distribution is narrowed significantly. The maximum price drops from the wholesale market cap of $5,000/MWh to $395/MWh, and the minimum price jumps from $5/MWh to $23/MWh.

Table 4
Statistical Distribution of Wholesale Electricity Prices in 2023, $/MWh

	Max	Min	Mean	Median
Base Case	5001	-5	35	26
No Solar	786	7	32	26
No Wind	5001	21	42	31
No Wind or Solar	483	23	31	29

Notice that the impact of removing solar is primarily to lower the maximum price, while the main impact of removing wind is to raise the minimum price . However, this outcome does not mean that wind volatility did not contribute to the price spikes. The model attributes the price spikes to solar because maximum prices in 2023 primarily occurred during the summer hours around sunset, as gas and energy storage were needed to ramp up to account for the ramp down of solar. Removing solar and replacing it with sufficient natural gas generation to cover peak demand at all hours eliminated the incidences of extreme scarcity pricing (including the Energy Emergency Alert on September 6) and reduced ramping requirements, therefore reducing the price needed to induce sufficient generation to enter the market.

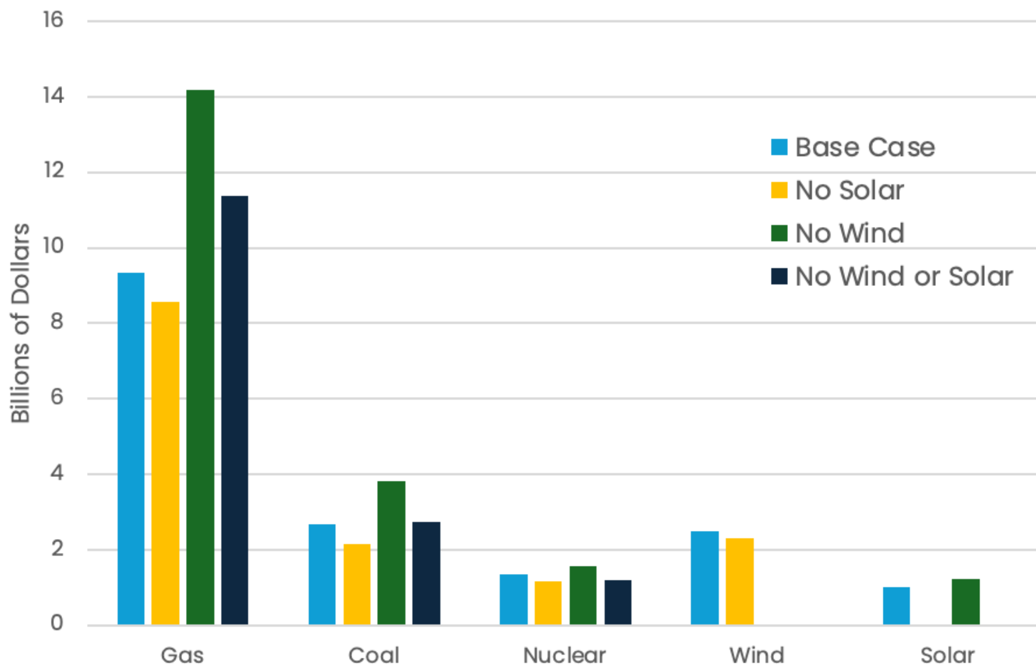
Wind is more dominant at night when prices are low, so removing wind brought the minimum price up from around zero—which is typically the marginal offer price for wind with almost no fuel or operating costs—to a value that is closer to the marginal offer price of baseload gas, coal, and nuclear. In the long run, increasing the minimum market price is critical for supporting healthy economics and future price certainty for thermal plants and reduces the need for high price periods to induce sufficient new generation builds. As noted above, despite lower overall revenue in the market when wind and solar are removed, the average price received by gas, coal, and nuclear only fell by a few percentage points. Given such a small change in the average price, the reduced uncertainty in prices without wind and solar would likely induce developers of new gas power plants to build more in the ERCOT market.

IMPACT OF WIND AND SOLAR ON MARKET REVENUES FOR GAS, COAL, AND NUCLEAR

Having assessed the total revenue and market prices in each of the four scenarios under study, the next step is to assess the revenue and price impacts on different resources. **Figure 5** shows the total energy market revenue by fuel; note that from here on, we will not include the PTC, which applies only to wind, or other revenue, which is relatively small and is separate from wholesale energy sales. While total energy revenue declines by $1.5 billion from the base case to the case with no wind and solar—reflecting the elimination of nearly $3.6 billion in revenue from wind, solar, and energy storage—revenue to gas generators increases by $2.1 billion. Revenue to coal increases slightly, primarily due to increased coal generation, revenue to nuclear declines slightly, a reflection of the slightly lower average market price in the scenario without wind and solar.

Dividing total energy revenue by total generation for each resource produces an average market price for each resource. The reason solar is the main driver of higher market revenues—and therefore costs to consumers—is that its presence is driving up prices

Figure 5
2023 Total Energy Revenue by Fuel, in Billions of Dollars



Wind Earned More from the Production Tax Credit than from Electricity Sales in 2023

An important source of revenue not shown in **Figures 4** or **5** is the production tax credit (PTC) for wind generators. In total, the model shows that wind brought in $2.5 billion in energy revenue, $3.45 billion in PTC revenue, and $174 million in other revenue. In other words, wind generators made nearly $1 billion more in 2023 from the PTC than they did from selling electricity. The model assesses the value of the production tax credit for wind in revenue terms at $32/MWh, which is greater than the actual PTC value because the PTC is a pre-tax item, whereas the average price of energy received by wind in 2023 was only $19/MWh. This data makes it clear that the vast majority of wind generation in ERCOT would not be profitable without the PTC.

While the model output does not distinguish between PTC revenue and other sources of non-energy revenue, we approximated the PTC revenue by assuming that wind units receiving more than $30/MWh in other revenue received the PTC. Some wind units may have received the PTC at a reduced rate, while some that we counted as receiving $32/MWh may not have received that full rate for the entire year, so we think these factors balance out to give us an accurate approximation of the total amount. Because many wind units are older than 10 years, they do not receive any PTC revenue unless they have repowered. In total, we estimated that 280 of the 370 wind units in ERCOT in 2023 received the full PTC.

Because the PTC is not revenue derived from ERCOT ratepayers, it does not represent a "system cost" in the same sense as revenue from electricity sales and ancillary services. Therefore, the true difference in system cost between the base case and the no wind or solar case is not $5.6 billion, which is the absolute difference between the total revenue in both cases, but rather the $2.15 billion number shown in **Figure 4**.

for every other resource. Part of this outcome is due to the increased ramping needs that solar imposes on thermal generators every day as the sun rises and sets. The inefficiency of ramping units compared to running them at the same rate all day, like a car in stop-and-go traffic compared to a car driving at a constant speed, leads to higher operating costs and requires higher prices for those units to enter the market. However, most of the change is likely due to the elimination of high prices at the end of the day by ensuring there is enough dispatchable generation to cover demand at all hours. The model is clear that these effects overwhelm the positive effect of solar keeping down prices during the daytime hours.

Wind, on the other hand, has very little effect on average market prices for the other fuels. Comparing the "No Wind and Solar" column to the "No Solar" column shows that adding wind reduces prices slightly for nuclear while increasing them slightly for coal and gas. Wind also has the effect of mitigating the price increases caused by solar. However, the positive effects of wind come at a price, which is the siphoning of revenue from thermal generators needed to keep those generators in the market and to induce new builds. Given the low output of wind during peak demand hours and its high variability compared to thermal resources (see **Figures 1a** and **1b**), the presence of wind is creating a long-term capacity shortage in ERCOT that will continue to manifest in the form of more frequent scarcity conditions.

A few more illuminating conclusions can be drawn by looking at the seasonal changes in energy revenues across the four different scenarios, which are shown in **Figure 7**. First, the reduction in revenues achieved by replacing solar with gas (compare the "Base Case" column to the "No Solar" column) is entirely due to lower revenue in the summer, with the slight reduction in winter revenue offset by higher revenue in the spring and fall. The effect of wind is almost opposite to that of solar; replacing wind with gas slightly reduces energy revenue in the summer

Figure 6
2023 Average Wholesale Prices by Fuel, $/MWh

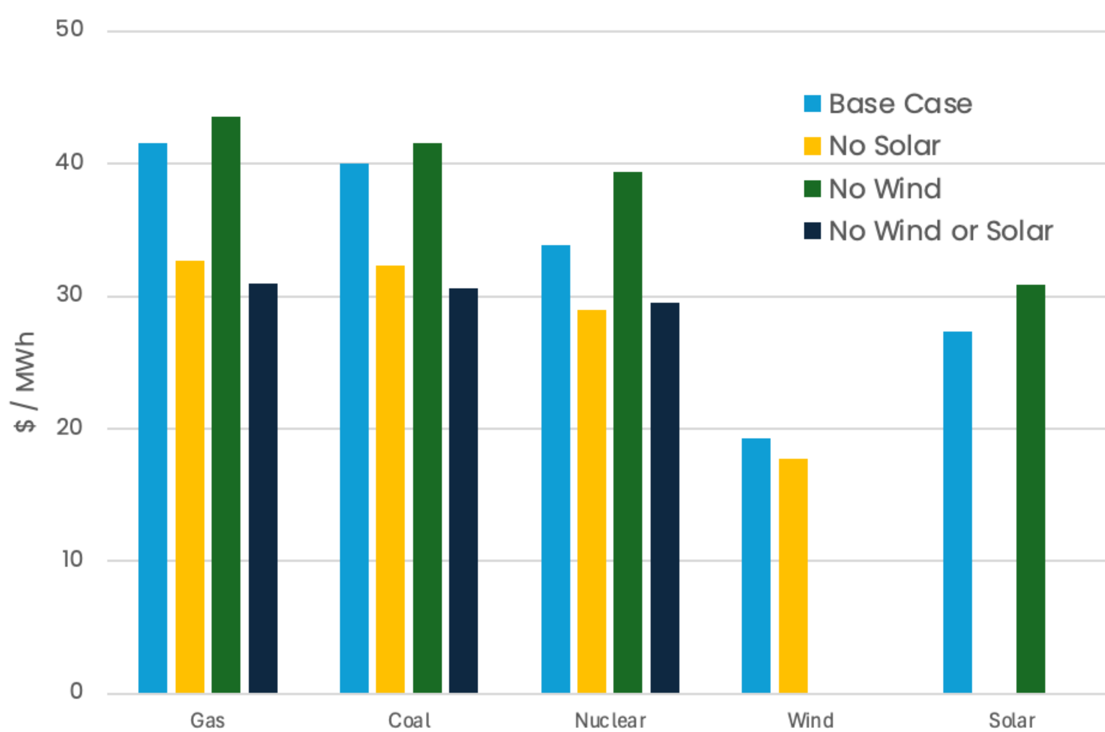
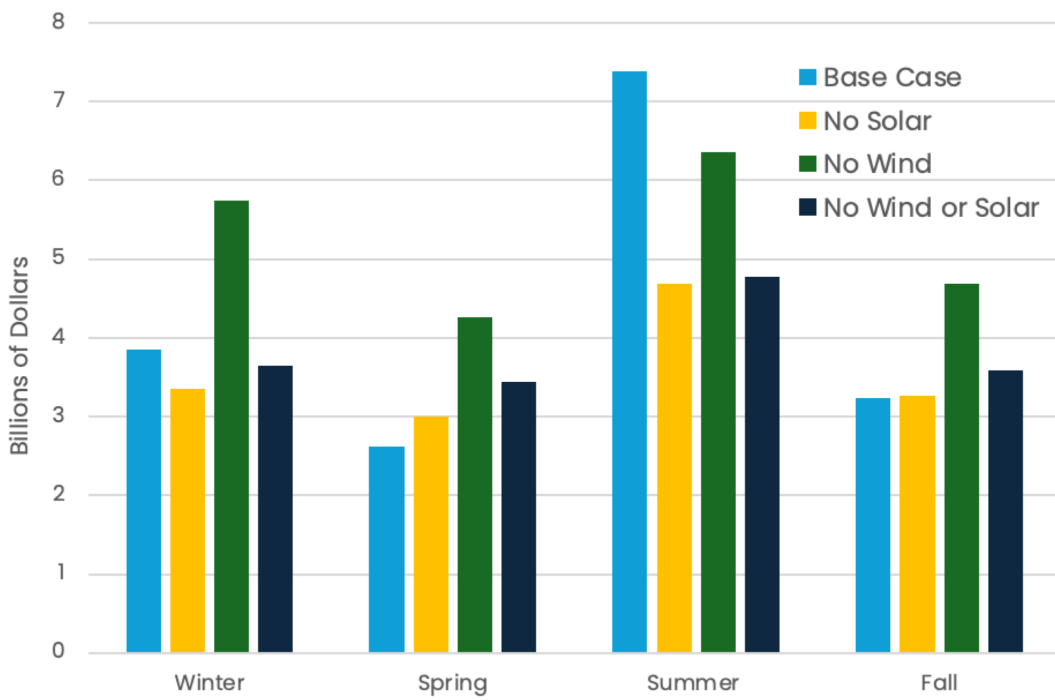


Figure 7

2023 Total Energy Revenue by Scenario, by Season, in Billions of Dollars



while increasing it in the other seasons, and the net effect is slightly higher revenues for the whole year.

Combining the information in Table 3 and in Figure 7, it is clear that the primary benefit of removing solar stems from eliminating the frequent scarcity pricing that occurred at the end of many days during the summer. What that means is that the price reduction comes not just from eliminating solar but also from replacing that solar with enough gas to cover demand across all hours of the day and the resulting reduction in price volatility. Therefore, the benefit of replacing solar comes less from the reduction in daily volatility and ramping needs and more from the fact that there is enough dispatchable capacity to cover demand along with a healthy reserve margin. Our conclusion is that consumers would reap considerable benefits if the ERCOT market properly valued capacity instead of relying upon a single clearing price for energy that pays wind and solar the same market price as dispatchable resources.

ALLOCATING THE COST OF ANCILLARY AND RELIABILITY SERVICES TO VARIABLE RESOURCES

The fundamental conclusion of this research is that the variability of wind and solar generators is leading to higher energy costs in the ERCOT market, and those costs are manifesting in two primary ways: 1) higher operating costs for thermal plants as they ramp up and down to match wind and solar output, and 2) more frequent price spikes due to the uncertainty in wind and solar output during high demand hours. There is also the direct cost of procuring more ancillary services to manage greater ramping requirements and to ensure the grid remains stable in the event of wind and solar output varying significantly from their forecasted values.

Faced with this reality and the potential for these costs to grow dramatically over the next decade, the question now is what can be done to correct the problem. Ancillary services will be dealt with in this paper, and wholesale market reforms will be addressed in a subsequent paper. Previous work from our group proposed a new ancillary service to require wind and solar generators to procure dispatchable resources to ensure their aggregate output never falls below a certain level during peak demand periods (Bennett, 2021). However, since that time, ERCOT has introduced the short-duration ERCOT Contingency Reserve Service (ECRS) (ERCOT, 2023b), and the 88th Texas Legislature mandated the adoption of a longer-duration Dispatchable Reliability Reserve Service (DRRS) (HB 1500, 2023, pp. 20-21). Therefore, this study recommends first allocating the cost of these existing ancillary services to variable generators (primarily wind and solar) before adding a new product.

Before expounding on this solution further, it is important to explain what ancillary services are in ERCOT and how their costs are currently allocated. The wholesale energy market in ERCOT procures energy on a day-ahead and real-time basis to meet electricity demand, and this market determines the majority of the energy costs that are ultimately passed onto ratepayers. But ERCOT also has a secondary market, called the ancillary services market, that is, in its essence, a means for ERCOT to pay generators to remain on standby to perform certain functions to ensure the grid frequency is kept stable at 60 Hz and to avoid sudden outages due to unforeseen fluctuations in electricity supply.

Currently, the cost of ancillary services is passed directly to ratepayers through a set fee based on how much electricity they consume during certain time intervals each year—the technical term for this is "load ratio share." However, SB 3 added statutory language to require the PUC 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" (SB 3, 2021, pp. 19-20). Therefore, if generators or other resources are determined to be causing the need for deployment of additional ancillary services, the statute says those resources should bear those costs.

In fact, ERCOT has already made this determination, as reflected in its recently published calculations for minimum ancillary service procurements (Seely et al., 2024). The amount of frequency regulation (p. 3), non-spin reserves (p. 10), and ECRS (p. 16) procurements are all determined to varying degrees by the forecast error in net load (demand minus wind and solar output). As ERCOT explains in the document (p. 10), more wind and solar in the system leads to larger forecast errors in their aggregate output and increases the need for ancillary services.

The PUC's study on the cost of backing up variable generators approximates ERCOT's procurement methodology to discern the quantity and cost of ancillary services procured to cover variability in load, dispatchable generation, and non-dispatchable generation. The study attributed $788 million (PUC, 2024, p. 12), or 42% of the total cost of ancillary services in 2023, to uncertainty in wind and solar output (see **Table 5**), with only 23.4% of the cost attributed to load and 34.6% to dispatchable generation. These are clear statements of cost-causation, yet ERCOT and the PUC continue to ignore their statutory obligations and place the cost burden entirely on consumers.

Fortunately, the 88th Texas Legislature required the PUC to study the whether the cost allocation of ancillary and reliability services to generators would result in a net savings to consumers (HB 1500, 2023, pp. 23-24). However, the study is not required to be published until December 1, 2026, and the statute gives no mandate to implement cost allocation if the study produces a positive result. Given the reluctance of the PUC and ERCOT to broach this issue and the potential for litigation without clear direction from the Legislature, the Legislature should modify this statute to require the PUC to adopt any new cost allocation method that it finds will benefit consumers relative to the current method.

The Legislature is not the only entity to say that cost allocation is needed. On July 6, 2021, a month after SB 3 became law, Governor Greg Abbott issued a letter

Table 5

2023 Ancillary Service Costs Distributed based on Associated Risks, in Millions of Dollars

Month	Regulation		RRS	ECRS		Non-Spin			All A/S			
	L	ND	D	L	ND	L	D	ND	L	D	ND	ALL
Total	56.7	112.5	525.3	209.8	503.9	171.5	123.2	171.2	438.0	648.5	787.6	1,874
Percent	33.5	66.5	100	29.4	70.6	36.8	26.4	36.7	23.4	34.6	42.0	100

Note: Data from *Report on Dispatchable and Non-Dispatchable Generation Facilities*, Public Utility Commission of Texas, 2024, p. 12 (https://interchange.puc.texas.gov/Documents/56335_8_1445570.PDF). Regulation = frequency regulation, both up and down; RRS = responsive reserve service; ECRS, = ERCOT Contingency Reserve Service; Non-Spin = non-spinning backup power; L= load; D = dispatchable generation; ND = non-dispatchable generation.

that directed the PUC to take four specific actions, all of which are worth quoting in their entirety:

- 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. (Letter from Gov. Greg Abbott to PUC, 2021, pp. 1-2)

To the PUC's credit, they have acted swiftly on the first, third, and fourth items, although the first and fourth items are still far from complete. However, they have yet to even begin a rulemaking for cost allocating ancillary services to generators, despite the statutory requirement created by SB 3 and this directive from Governor Abbott. ERCOT's most recent ancillary services study, which informed the procurement methodologies described above, avoids this question altogether (ERCOT, 2024d).

This issue is also urgent because of the forecasted explosion of demand in ERCOT over the rest of this decade (Morris and Lamb, 2024), Under ERCOT's more conservative assumption of computing load growth (Morris and Lamb, 2024, pp. 7-9, "Base + EV + LFL 15% - PV + Contracts + Contracted LFL" scenario), summer peak demand is forecasted to rise from 85 GW in 2024 to about 112 GW in 2030 and winter peak demand from 78 GW to about 102 GW. Forecasted generation additions from 2025 to 2027 are 3.3 GW of wind, 28 GW of solar, and 16 GW of energy storage, along with only 1.5 GW of new gas generation (ERCOT, 2024a). Therefore, most of the increase in peak demand between now and 2030 (absent a rapid increase in new gas generation from 2028 to 2030) will be met by a combination of new solar and energy storage resources.

CONCLUSION

A key point that is often missed in debates about electricity policy is that the goal is to design the grid to *maximize benefits to consumers*. And by benefits, we mean the right balance of cost and reliability so that all classes of consumers—residential, commercial, and industrial—can maximize the utility they derive from the system at the lowest possible cost. The challenge for lawmakers and regulators is that they are bombarded with information from numerous market participants and from special-interest groups who place a heavy weight on certain benefits or attributes over others. Lawmakers and regulators need to synthesize that information into decisions that will provide the most benefit for the most people, which can be challenging when most of the groups lobbying them do not have that big-picture interest . The goal of this research program is to help with that task.

The problem with integrating large amounts of wind and solar generation into the ERCOT grid is that those generators *impose* costs on the system in addition to providing the benefits of free fuel and low operating costs that can (at times) reduce energy prices. The ERCOT market exacerbates this problem by utilizing a single market clearing price for energy that pays all generators the same price regardless of their dispatchability. Furthermore, because wind and solar always bid lowest, they are always dispatched first, meaning dispatchable power plants are forced to react to changes in wind and solar generation by adjusting their output. It is as if 85-octane gasoline was priced the same as 93-octane, and a car owner was required to buy 85-octane whenever it was available even though their car was designed to run on 93-octane. The car owner may be able to run for a while on 85-octane, but eventually, the cost of their car breaking down will likely be greater than if they had bought the 93-octane gasoline all the time.

If the current wholesale market regime is maintained in ERCOT, and if reliability costs continue to be shifted entirely to consumers, then the imposed costs of wind and solar will not be properly distributed. In addition, if the existing federal subsidies remain in place, then wind and solar generation and their associated costs will continue to grow unabated. Ratepayers will either have to pay more and more to keep dispatchable power available during times of low wind and solar output or shoulder the cost of more blackouts. The steep rise in electricity rates over the past decade in California (EIA, n.d.-a)—which has less combined wind and solar generation than Texas but more variability in its system due to the smaller size of its grid—forecasts what will happen in Texas unless this problem is addressed now.

We first outlined a solution to this problem in our 2021 paper and put forward a guiding principle for policymakers that applies today even more than it did three years ago:

> 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. (Bennett, 2021, p. 11)

Put another way, competitive wholesale electricity markets can only maximize benefits to consumers when they enforce "uniform reliability standards where companies have the proper incentives to maximize the quality of electricity service for ratepayers" (Bennett, 2021, p. 14).

The first step toward achieving that goal is to properly allocate the cost of ancillary and reliability services that ERCOT procures to both load and generation according to their variability, rather than forcing consumers to shoulder that entire cost. The second step (which will be addressed in a forthcoming study) is to correct the imbalances in the wholesale market by weighting the payments given to different generators according to their reliability, thereby ending the current regime of overpaying unreliable generators and underpaying for reliability. If these two reforms are implemented, ERCOT will be able to avoid the abyss of constant outages and soaring prices caused by unreliable generators and will maximize its competitive market to the benefit of all Texas ratepayers. ■

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