



The Financial Fallout *From Winter Storm Fern*

**How Disappearing Wind and Solar Generation
Cost Texans an Additional \$766 Million**

Isaac Orr, Mitch Rolling, and Sarah Montalbano



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COST TEXANS AN ADDITIONAL \$766 MILLION



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INTRODUCTION

In the wake of Winter Storm Fern, the U.S. Department of Energy (DOE) released information demonstrating that power generation from America’s thermal fleet carried the day, as coal, natural gas, nuclear, and oil, particularly in New England, provided 86 percent of the power generated during the peak of the storm.¹ In contrast, DOE’s release noted that wind and solar generated just 8 percent and 2 percent of the nation’s electricity, respectively, during the period of peak system stress.

This is despite the fact that U.S. Energy Information Administration (EIA) data show wind and solar constituted roughly 23 percent of the total installed capacity on the grid in January, meaning they underperformed relative to their installed capacity on the nation’s power grid (see Figure 1).

The American Clean Power Association (ACP), the

top lobbying arm of the wind and solar industry, has released its own narrative around the performance of wind, solar, and storage resources during Winter Storm Fern, arguing that wind and solar saved American consumers more than \$2 billion during the winter weather event, including \$200 million in savings in the Electric Reliability Council of Texas (ERCOT) Region.²

However, ACP’s fact sheet did not describe the methodology used to determine these purported savings, and the organization did not respond to requests from Always On Energy Research (AOER) for more information about its calculations.

Therefore, AOER conducted its own analysis and determined that it is exceedingly unlikely that wind and solar saved Texans living in the ERCOT footprint *any money*. In fact, our analysis found low wind and solar generation during the height of the storm on January 25 likely cost Texans an additional \$766 million in wholesale power costs in just 17 hours.

- 1 U.S. Department of Energy, “Fact Sheet: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms,” February 6, 2026, <https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms>.
- 2 American Clean Power Association, “Clean Energy Saved Consumers 2+ Billion During Winter Storm Fern,” Accessed March 10, 2026, <https://cleanpower.org/resources/clean-energy-saved-consumers-2-billion-during-winter-storm-fern/>.

FIGURE 1: U.S. INSTALLED POWER PLANT CAPACITY AS OF JANUARY 2026

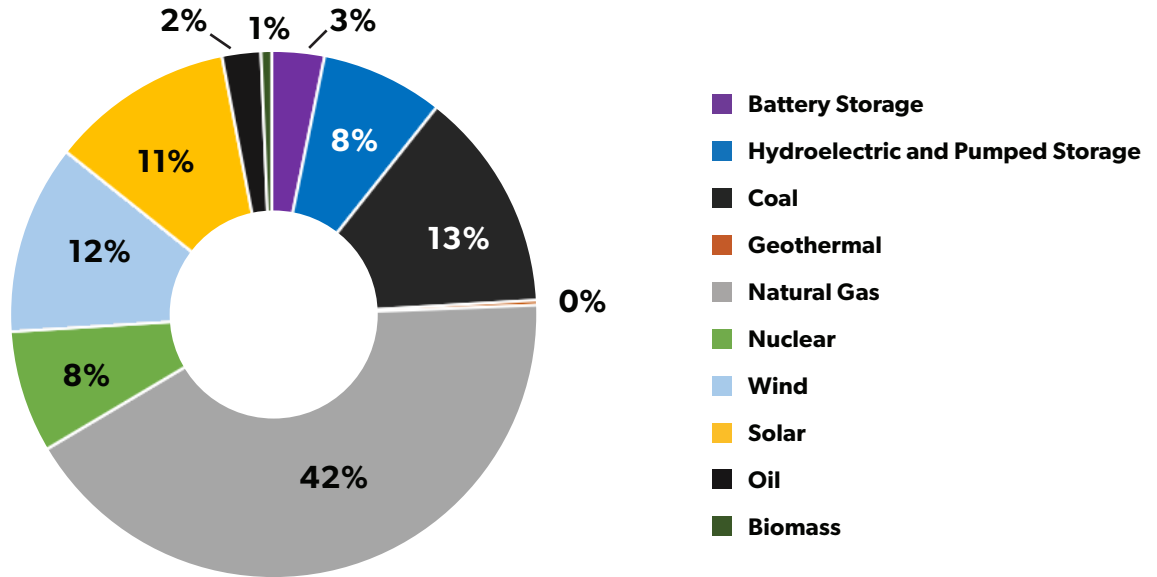


Figure 1. The thermal fleet constituted 66 percent of U.S. installed capacity but provided 86 percent of peak energy needs. In contrast, wind, solar, and batteries constituted 23 percent, and wind and solar contributed a combined 10 percent of the nation’s electricity.

ERCOT’S GENERATION MIX

ERCOT has become increasingly dependent on weather-dependent resources, particularly wind energy, to meet its peak energy demand.

U.S. EIA data indicate that ERCOT has not added any net thermal capacity since 2013, as natural gas additions have been offset by coal plant closures.³ Furthermore, the amount of thermal generation capacity on the ERCOT system has decreased since 2016, despite peak demand increasing by over 12,000 megawatts (MW), or by over 17 percent, in the last 10 years.⁴

According to the ERCOT Monthly Outlook for Resource Adequacy (MORA) report for January 2026, ERCOT had 183,709 MW of total installed capacity on its system during Winter Storm Fern, with a nameplate capacity of 87,938 MW for thermal resources and 93,828 MW for wind, solar, and battery storage.⁵

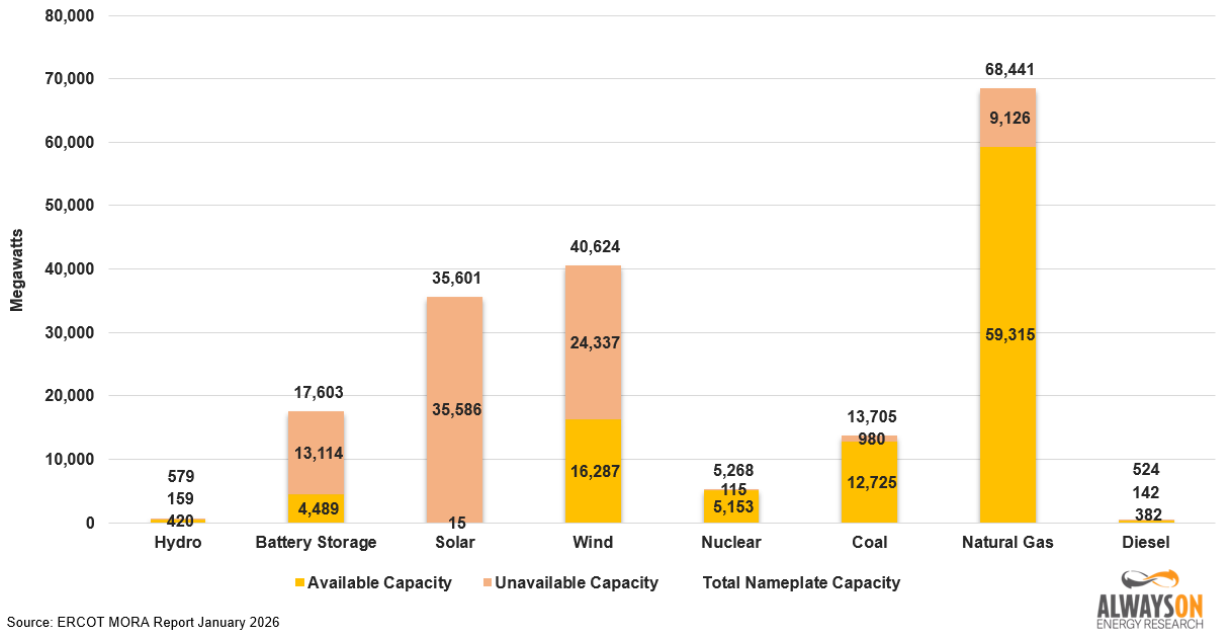
On paper, this should have been more than enough capacity to weather Winter Storm Fern, which saw a peak demand of slightly more than 75,000 MW, without a massive spike in prices. However, the ERCOT MORA data show that not all of this capacity is expected to be available during peak winter storm conditions, which occur in the mornings before

³ U.S. Energy Information Administration, “Texas Electricity Profile 2024,” State Electricity Profile, November 10, 2025, <https://www.eia.gov/electricity/state/texas/>.

⁴ Ibid.

⁵ ERCOT, “Monthly Outlook for Resource Adequacy (MORA) Reporting Month: January 2026,” Accessed March 10, 2026, https://www.ercot.com/files/docs/2025/11/07/MORA_January2026.pdf.

FIGURE 2: ERCOT INSTALLED AND EXPECTED AVAILABLE CAPACITY DURING WINTER STORM FERN HOUR ENDING 8 A.M. CST

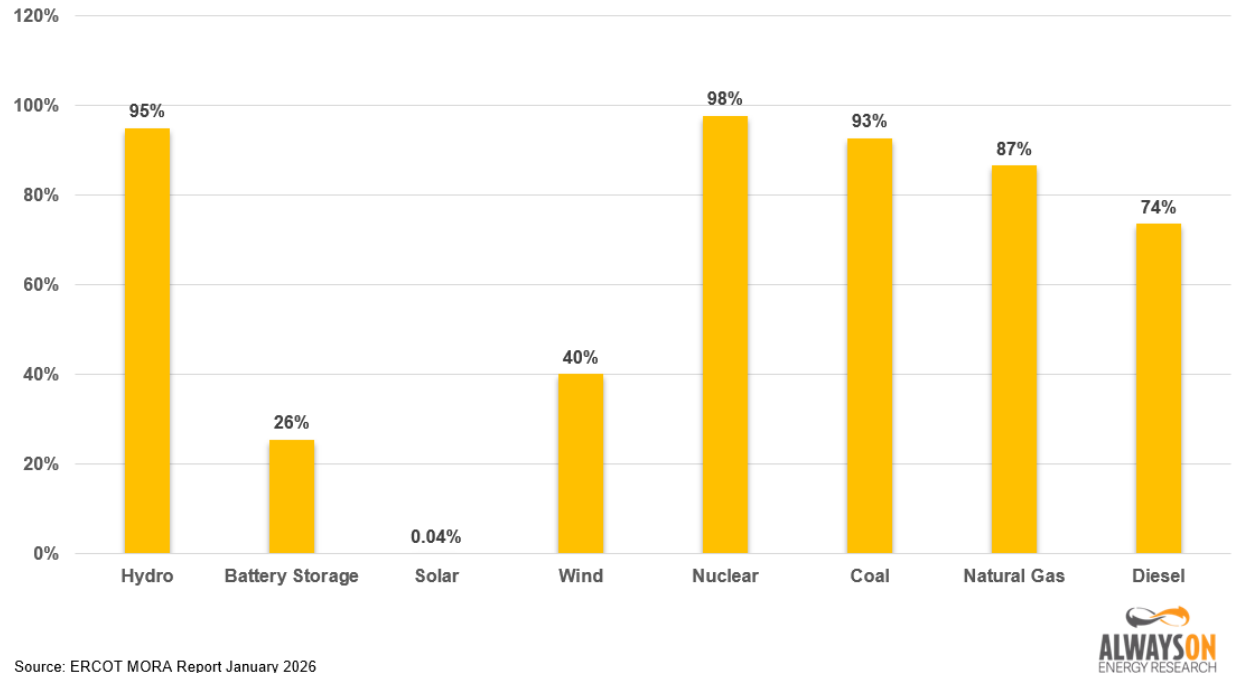


Source: ERCOT MORA Report January 2026



Figure 2. Expected available and expected unavailable capacity in ERCOT for January 2026. These figures include the planned resources in the MORA report.

FIGURE 3: ERCOT EXPECTED AVAILABILITY FACTORS DURING AN 8 A.M. PEAKING EVENT JANUARY 2026



Source: ERCOT MORA Report January 2026



Figure 3. The availability factor for each resource was calculated as the expected available capacity divided by the total nameplate capacity. Nuclear power has the highest availability factor, while solar has the lowest.

FIGURE 4: ERCOT HOURLY ELECTRICITY GENERATION BY SOURCE DURING WINTER STORM FERN

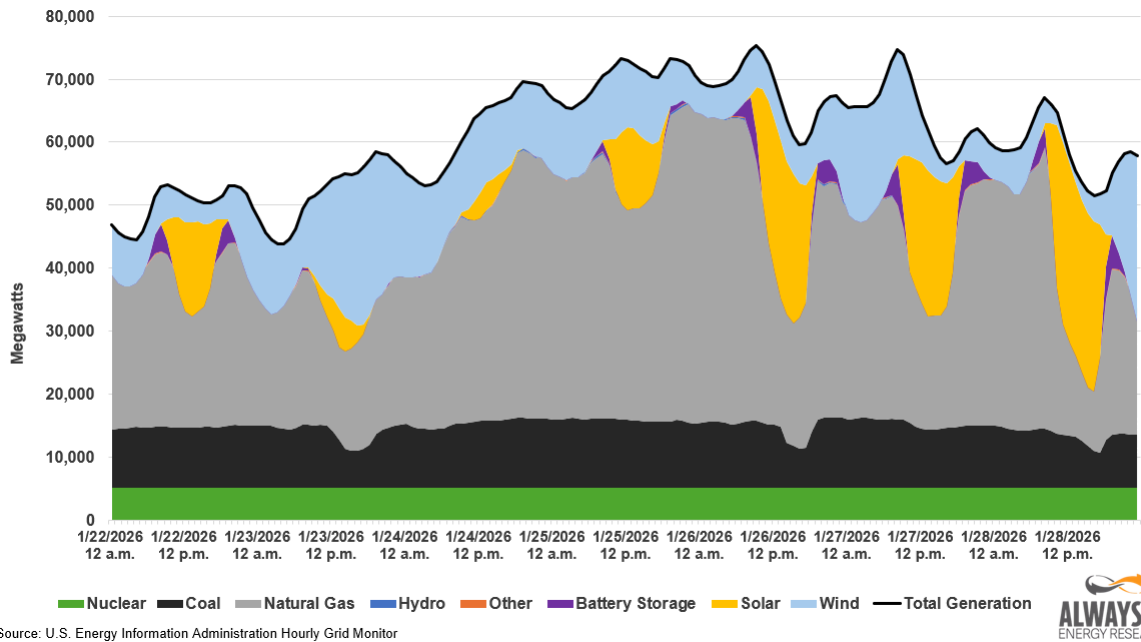


Figure 4. System conditions were tightest from January 25 at 5 p.m. through January 26 at 8 a.m. At 10 p.m., the thermal fleet was generating 66,086 MW while wind, solar, and battery storage were delivering just 5,706 MW, as batteries were consuming power at the time to recharge.

sunrise. Figure 2 shows the expected available capacity, unavailable capacity, and total installed (nameplate) capacity for each resource in ERCOT according to the MORA report.

There is a distinct difference in the expectations for performance between thermal generators, which have availability factors of 74 percent for diesel generators and 98 percent for nuclear plants, and the wind, solar, and storage fleet, which were expected to have availability factors of 40 percent, 0.04 percent, and 26 percent, respectively, during an 8 a.m. peaking event (see Figure 3).

While ERCOT expected very little contribution from solar resources during a peaking event, when demand is highest during the evening and early-morning hours, the region’s wind resources underperformed their expected 40 percent availability factor, producing just 17 percent of their potential output on January 26 at 8 a.m. (see Figure 4).

WHOLESALE POWER PRICES ROSE AMID TIGHT SUPPLY CONDITIONS

Tight system conditions from the evening of January 25 through the morning of January 26 led to a substantial increase in wholesale power prices in ERCOT.

Day-ahead and real-time wholesale price data from S&P Global data show prices increased in concert with reduced wind and solar generation. Figure 5 shows day-ahead (dark green line) and real-time (light green line) increasing slightly with the overall rise in demand. However, prices did not increase substantially until electricity production from wind and solar declined.

S&P Global data show day-ahead prices reached a high of \$1,832 per megawatt-hour (MWh), and real-time prices reached \$871 per MWh, resulting in dramatically higher power costs for Texas families and businesses.⁶

⁶ S&P Global Capital IQ, HB-BUSAVE Day-Ahead and HB-BUSAVE Real-Time Price Data.

FIGURE 5: ERCOT WHOLESALE ELECTRICITY PRICES AND WIND AND SOLAR GENERATION DURING WINTER STORM FERN

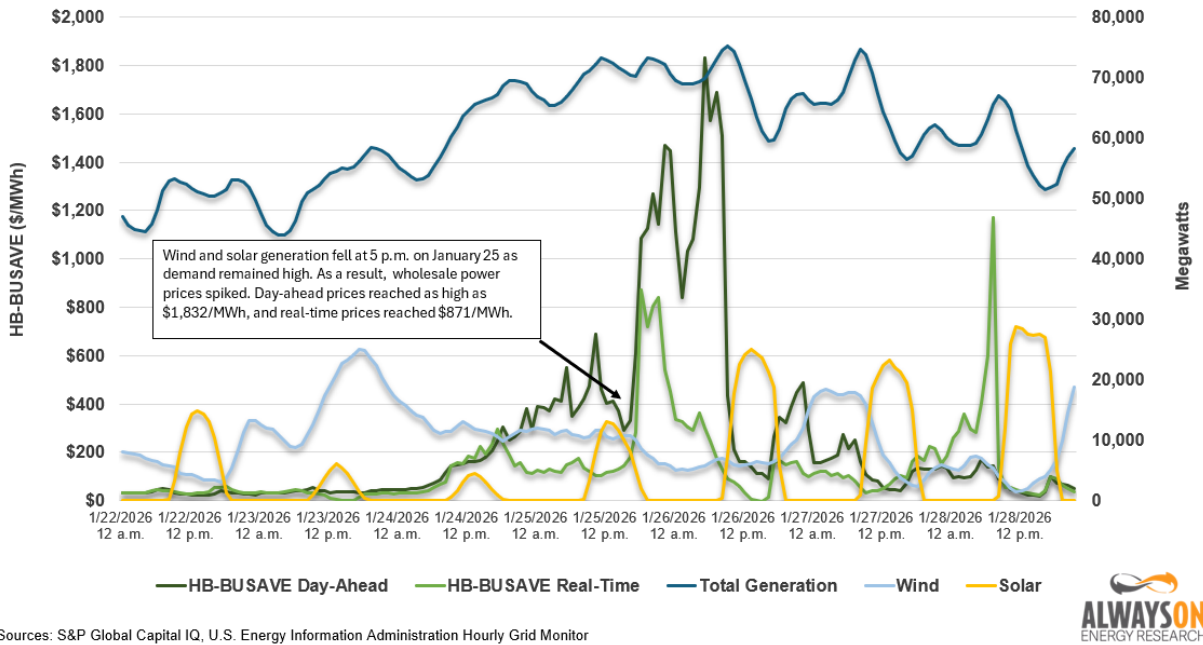


Figure 5. Wholesale power prices rose substantially due to sustained high demand and reduced generation from wind and solar facilities.

ERCOT data indicate that approximately 62.5 percent of all MWhs purchased in January 2026 were bought on the day-ahead market, and 37.25 percent on the real-time market.⁷ Using this ratio, blended hourly wholesale power costs for consumers were calculated, enabling AOER to determine the additional costs to consumers compared to wholesale power costs before the reduction in energy production from variable energy sources.

Figure 6 shows the combined hourly wind and solar capacity factor and the settled energy cost in ERCOT

during Winter Storm Fern.⁸ It also shows the additional power costs, shaded in light red, incurred due to the drop in wind and solar generation, relative to a \$20 million-per-hour power baseline cost, shown by the red line. The total additional cost of the light red areas is \$766 million over 17 hours.

This analysis used an hourly baseline power cost of \$20 million, which was the approximate cost of power at 4 p.m. on January 25, the hour just before wind and solar output dropped during the high-demand period.

7 ERCOT, “ERCOT Monthly Operational Overview (January 2026),” February 17, 2026, <https://www.ercot.com/files/docs/2026/02/18/ERCOT-Monthly-Operational-Overview-January-2026.pdf>.

8 Hourly capacity factors were obtained by dividing hourly generation from the U.S. EIA by the installed capacity listed in the ERCOT MORA report for January 2026.

FIGURE 6: ADDITIONAL ERCOT HOURLY WHOLESALE POWER COSTS DUE TO LOW WIND AND SOLAR GENERATION

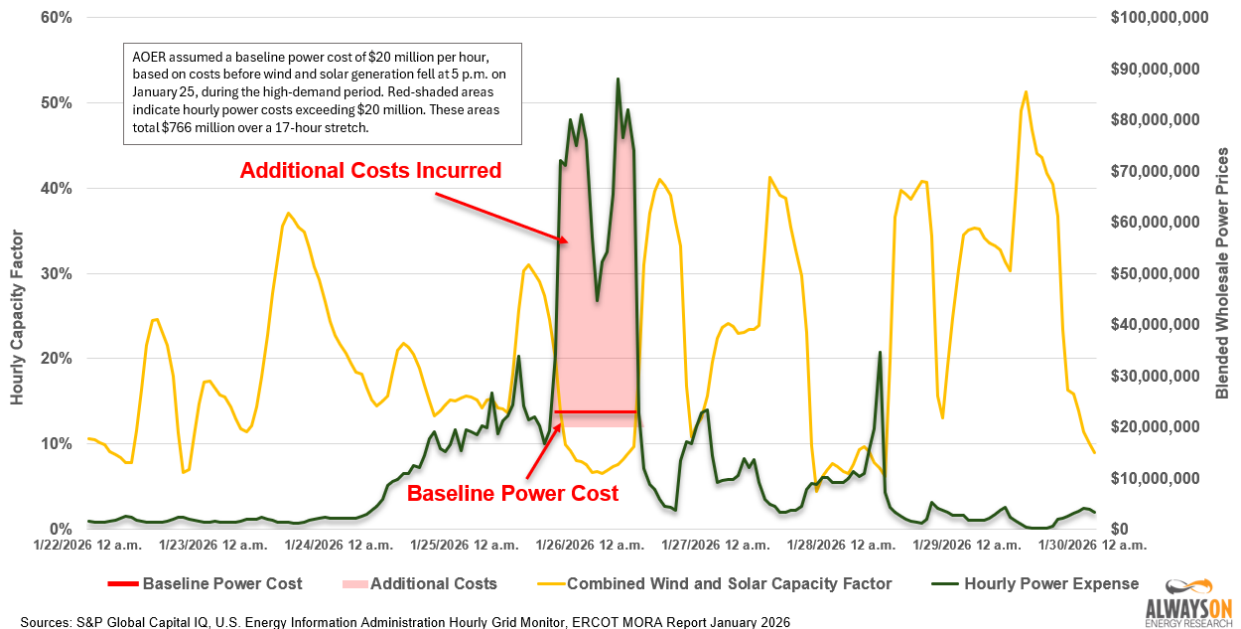


Figure 6. Wholesale power prices increased substantially as the output of the wind and solar fleets dipped below a 10 percent combined capacity factor during the height of the storm.

THE ANATOMY OF A PRICE SPIKE: WHY DID THEY RISE SO HIGH?

Ultimately, the increase in wholesale power prices resulted from high demand and inadequate supply. These dynamics were also amplified by the ERCOT demand forecast, which had estimated that peak electricity demand would be approximately 10 gigawatts (GW) higher than the actual realized peak from January 25 through January 26, putting additional upward pressure on day-ahead wholesale prices.⁹

Data from Grid Status shows outages for thermal units, wind, and solar during Winter Storm Fern (see Figure 7).¹⁰ Wind and solar had lower initial outages, but outages increased substantially on January 24 as the cold front moved in.¹¹ In contrast, thermal facilities had relatively low outage rates, with availability ranging from 86 to 88 percent during the price spike event, which lasted from the evening of January 25 through the morning of January 26.

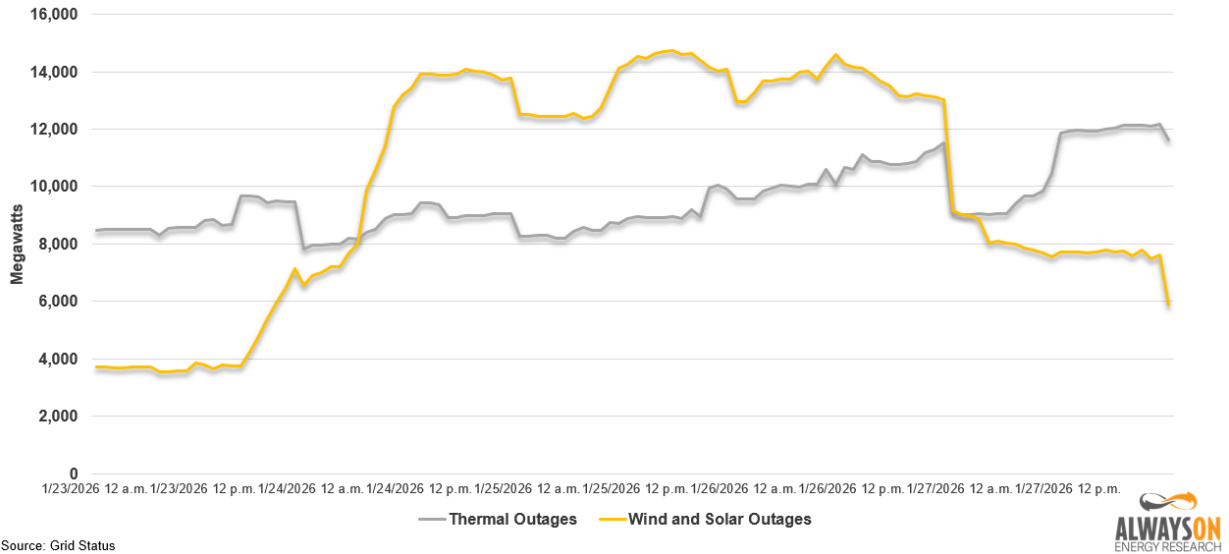
The outages reduced ERCOT's reserve margin, defined

⁹ U.S. Energy Information Administration, "Electric Reliability Council of Texas, Inc. (ERCOT) Electricity Overview (Demand, Forecast Demand, Net Generation, and Total Interchange) 1/22/2026-1/28/2026, Central Time," Hourly Grid Monitor, Accessed March 11, 2026, <https://www.eia.gov/electricity/gridmonitor/expanded-view/custom/pending/ElectricityOverview-13/edit>.

¹⁰ Grid Status, "ERCOT Thermal Generation and Outlook," January 23, 2026-January 28, 2026, <https://www.gridstatus.io/charts/ercot-outages?iso=ercot&outageType=thermal&date=2026-01-23to2026-01-28>.

¹¹ Grid Status, "ERCOT Wind+Solar Generation Outages and Outlook," January 23, 2026-January 28, 2026, <https://www.gridstatus.io/charts/ercot-outages?iso=ercot&outageType=irr&date=2026-01-23to2026-01-28>.

FIGURE 7: ERCOT THERMAL AND WIND AND SOLAR CAPACITY OUTAGES DURING WINTER STORM FERN



Source: Grid Status



Figure 7. Thermal outage rates remained below 10 GW from January 23 through January 27. Wind outage rates increased to 14 GW on January 24 and remained elevated until January 27.

in this report as the available thermal and battery storage capacity on the system from Figure 2, minus hourly outages (Figure 7), plus real-time wind and solar generation during every hour of the storm. The reserve margin was calculated using this method because wind generation underperformed its expected output of 16,287 MW during the entirety of the price spike event.

Figure 8 shows the amount of thermal and battery storage capacity available to meet peak demand, the power provided by wind and solar, and the hourly demand on ERCOT from January 23 through January 27. The red line shows the reserve margin, which fell from over 90 percent on January 23, when demand was lower, and wind, solar, and storage were able to deliver more power to the grid, to just 6 percent at 8 a.m. on January 26.

Unsurprisingly, the falling reserve margin experienced

during this period is highly correlated with rising electricity prices. In fact, in an energy-only market like ERCOT, where the grid operator does not make reliability payments to dispatchable generators to be available during periods of high stress, like winter storms, high prices are the primary mechanism for keeping reliable plants online, as they capture large portions of their annual revenue during these scarcity events.

Figure 9 shows the hourly reserve margin and blended wholesale power price from January 23 through midnight on January 27. Wholesale prices begin to rise as the reserve margin drops below 50 percent on January 24 and increase steeply as reserve margins begin their descent on January 25.

Wind, solar, and storage advocates will no doubt argue that wind and solar decreased wholesale prices when they were available. However, the question is

FIGURE 8: ERCOT HOURLY AVAILABLE RESOURCES, ELECTRICITY DEMAND, AND RESERVE MARGIN

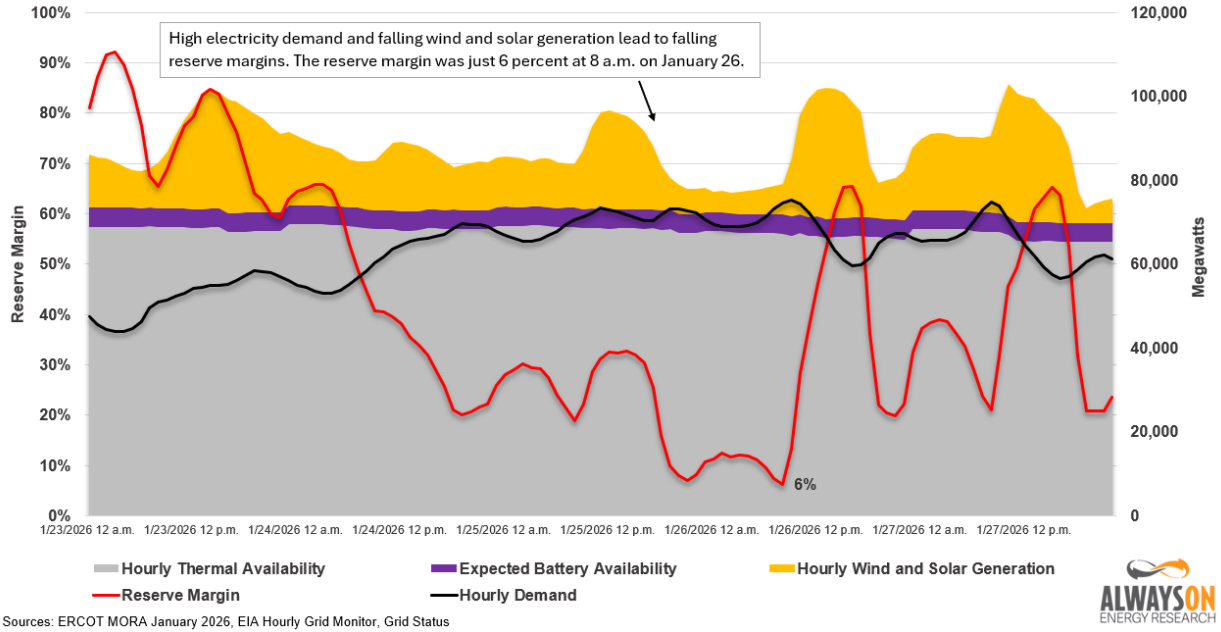


Figure 8. Reserve margins in ERCOT reached 6 percent during their lowest period.

FIGURE 9: ERCOT HOURLY RESERVE MARGIN AND WHOLESALE POWER PRICES DURING WINTER STORM FERN

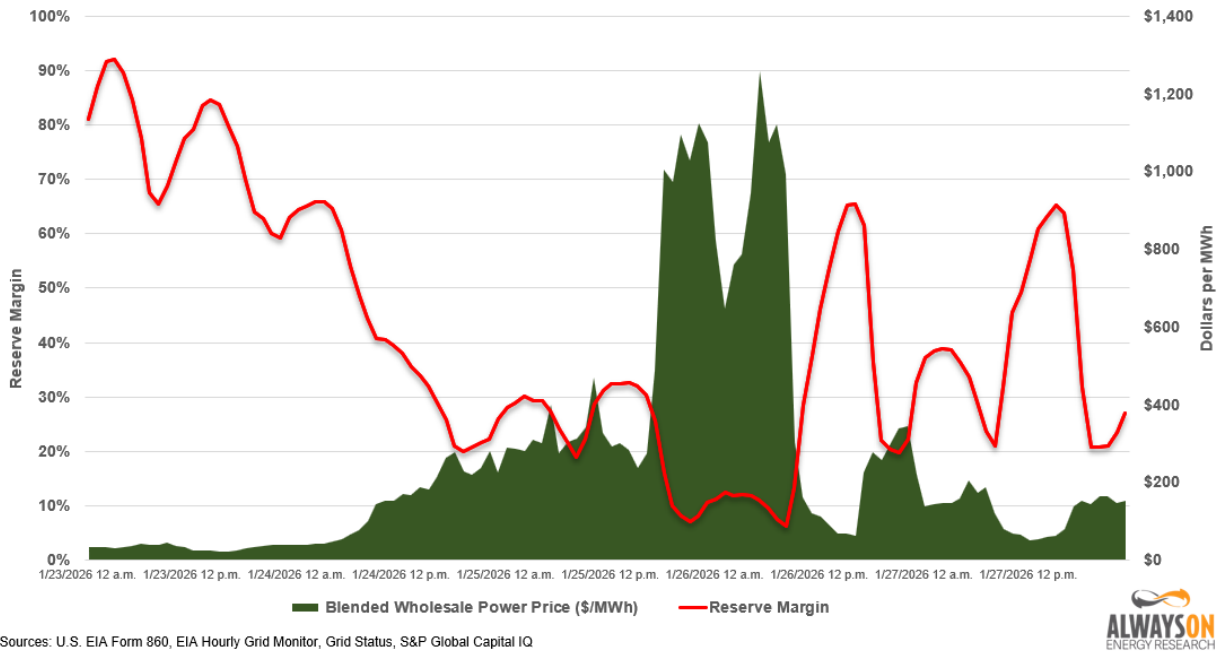
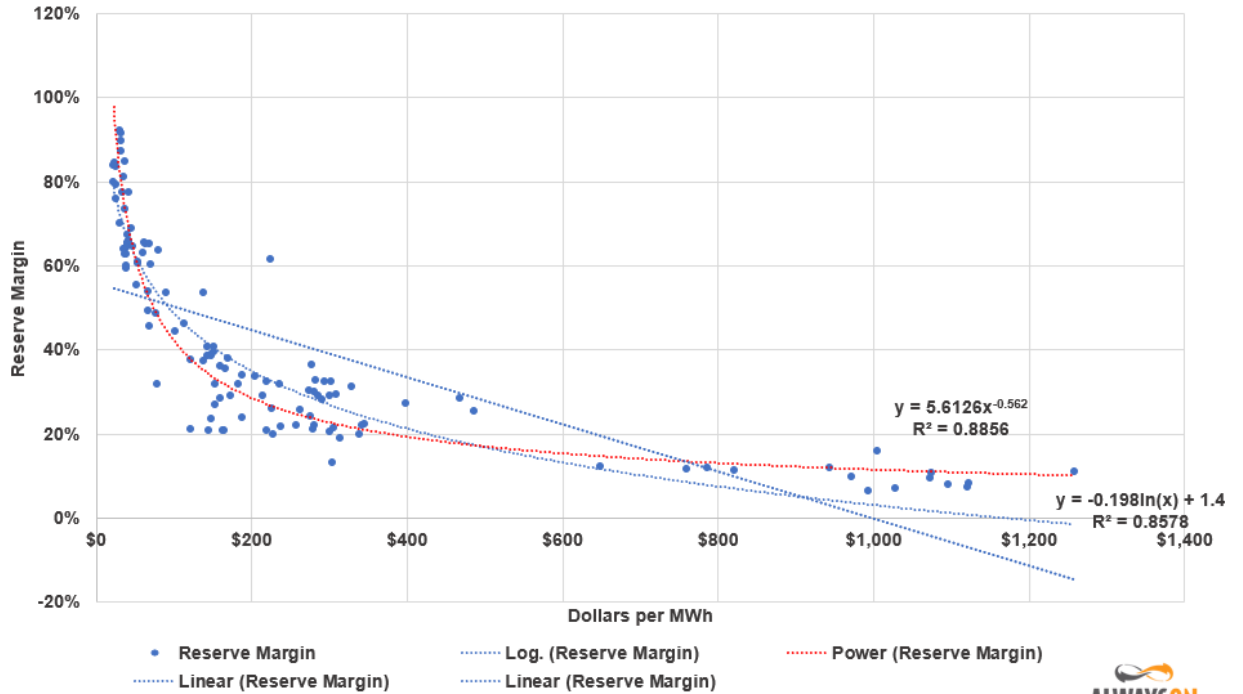


Figure 9. Wholesale power prices rose substantially as the reserve margin began to fall on January 24.

FIGURE 10: ERCOT WHOLESALE POWER PRICES BY RESERVE MARGIN DURING WINTER STORM FERN



Sources: ERCOT MORA January 2026, EIA Hourly Grid Monitor, Grid Status, S&P Global Capital IQ

Figure 10. Wholesale power prices increased substantially as reserve margins dipped below 20 percent. An R^2 of 0.8856 is high and unusual in real-world energy market data, indicating a very strong relationship between tightening reserve margins and higher wholesale prices.

not whether these resources can reduce wholesale costs at times, because they certainly can. Instead, the questions are: Is the grid properly valuing reliable generators, is it becoming overly reliant on weather-based resources, and could Texas achieve greater price stability and reliability at a fraction of the cost by adding more natural gas instead of wind, solar, and battery storage?

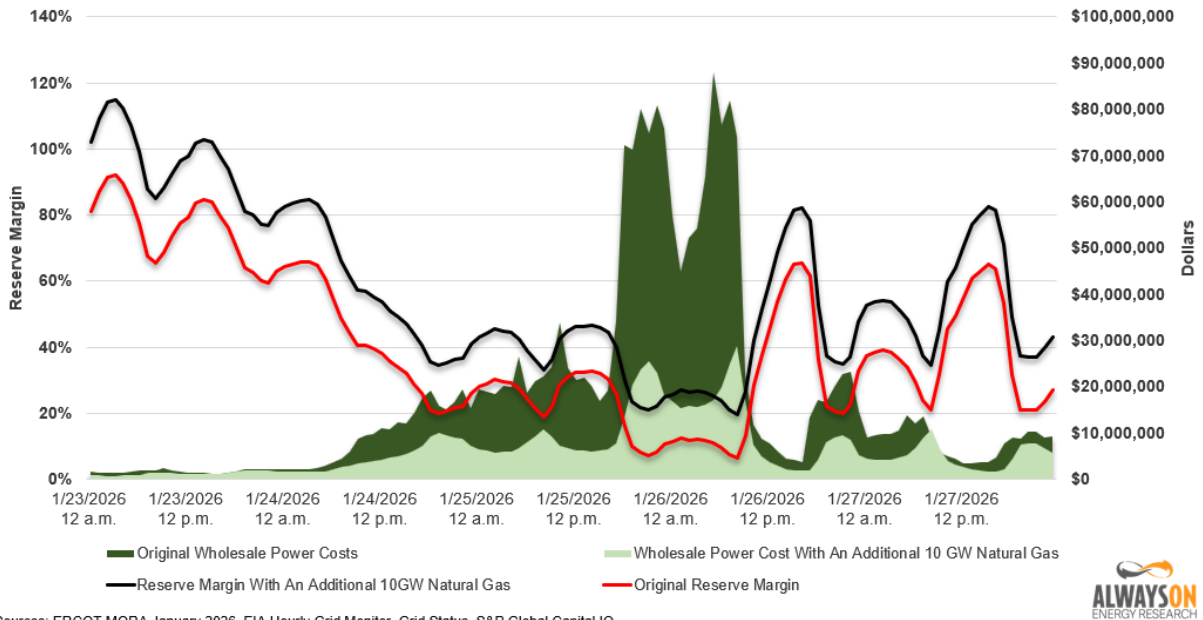
Figure 10 shows the wholesale electricity price in ERCOT as a function of the available reserve margin. Based on data from Winter Storm Fern, wholesale power prices increased dramatically when reserve margins dipped below approximately 20 percent. This relationship had an R^2 of 0.8856, meaning 88.56

percent of the variation in ERCOT wholesale prices in this dataset is explained by changes in available reserve margin.

Because the high prices can be explained largely by the scarcity of the system, adding additional dispatchable capacity could have increased the reserve margin during Winter Storm Fern, reducing wholesale power prices and costs to consumers.

To assess the potential consumer benefits of more dispatchable generation, AOER added 10,000 MW of hypothetical new natural gas capacity in ERCOT to assess the impact on hourly electricity costs and reserve margins by the blended wholesale power prices at a given reserve margin percentage in the

FIGURE 11: ERCOT ESTIMATED HOURLY POWER COSTS DURING WINTER STORM FERN WITH AND WITHOUT AN ADDITIONAL 10 GW OF NATURAL GAS



Sources: ERCOT MORA January 2026, EIA Hourly Grid Monitor, Grid Status, S&P Global Capital IQ



Figure 11. Adding 10,000 MW of new natural gas capacity would have increased reserve margins by 14 to 15 percent during the price spike, thereby yielding substantial savings for ERCOT residents.

original dataset, to the dollar per MWh costs after increasing the reserve margins with new natural gas capacity.

This analysis found that the new gas capacity could have saved Texas families and businesses \$1.34 billion in power costs. These savings are illustrated in Figure 11 by the difference between the dark-green and light-green shaded areas during the storm. These savings were driven by the fact that adding 10,000 MW of natural gas would increase the reserve margin by 14 to 15 percent during the evening of January 25 through the morning of January 26, thus reducing the scarcity prices incurred.

WHY HAS ERCOT FAILED TO ADD NEW THERMAL PLANTS?

While natural gas additions have mostly offset coal retirements, ERCOT hasn’t added any net dispatchable capacity since 2003. This is largely due to the energy-only market structure, which does not properly value the differences in reliability among generators, such as gas and coal plants, and among intermittent resources, such as wind and solar.

Furthermore, Texas does not require utilities to maintain sufficient backup capacity to ensure reliable power plants are available to meet electricity demand

when the wind isn't blowing or the sun isn't shining. In fact, the market structure in Texas specifically incentivizes reliable generators to exit the market.

This isn't a bug of the ERCOT market; it is a feature. In a 2018 article in PV Magazine detailing a report by the Wind Solar Alliance of Texas, the article author boasted about the parasitic effect [wind and solar] electricity generators have on the revenues of more reliable power plants.¹²

*This is just the beginning. Texas continues to add more wind every year, and ERCOT has estimated that the state could put online 13 GW of solar by 2030. **This will ultimately mean more hours where coal and gas plants are not operating, and more retirements of conventional generation.** [Emphasis added.]*

In the case of ERCOT, the parasitic impact of wind, solar, and now battery storage has not led to retirements, but it has dissuaded new thermal generators from entering the market at a time when

power demand is soaring due to population growth, industrial growth, and data centers.

CONCLUSION

Wind and solar can reduce wholesale power prices when they are producing, but their tendency to underperform during periods of peak system need can cause large spikes in wholesale prices. Our analysis suggests that the absence of wind and solar generation during the evening of January 25 through the morning of January 26 cost Texas families and businesses an additional \$766 million and left the region with only a 6 percent reserve margin.

Due to tight supply conditions, adding an additional 10,000 MW of natural gas to the ERCOT system would have been an effective way to increase reserve margins to at least 20 percent during the winter storm, yielding wholesale power cost savings of \$1.34 billion during the period of highest system stress.

¹² Christian Roselund, "Renewables Reduced Wholesale Power Costs by \$5.7 Billion in Texas," PV Magazine, November 6, 2018, <https://pv-magazine-usa.com/2018/11/06/renewables-reduced-wholesale-power-costs-by-5-7-billion-in-texas/>.