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WINTER STORM FERN SHOWS THE VALUE OF TRANSMISSION AND DIVERSE GENERATION

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Winter Storm Fern revealed how dramatically power generation varies by region and fuel type, and how avoidable supply constraints can quickly drive up consumers' energy costs. In doing so, the storm underscored the need for more interregional transmission capacity and other grid resources to meet rising demand for reliable, affordable electricity. Fern's impact was especially severe in the regions covered by the Southwest Power Pool (SPP), the Midcontinent Independent System Operator (MISO), and the PJM Interconnection, which together serve 130 million Americans. Storm-related data show that:

- Wind and solar resources performed well, while fossil-based generation faltered.
- In Fern as in other recent cold snaps, fossil generation accounted for the majority of generator outages. The coal units that the Department of Energy (DOE) had ordered to continue operating past their closure dates provided minimal support.
- Natural gas prices spiked during Winter Storm Fern and other recent severe cold-weather events, costing consumers billions of dollars.

These observations support the following recommendations:

- Policymakers and utility operators should take steps to enhance the power system's resilience by diversifying the generation mix, which will reduce ratepayers' exposure to economic and reliability risks.
- The Department of Energy should rescind its mandates that are blocking unneeded and unproductive generation facilities from exiting the market, increasing consumer costs and undermining market signals in the process.
- The Department of the Interior should remove permitting obstacles, including permitting pauses and revocations, that block market entry for new, low-cost resources that increase the diversity of the generation mix.
- Expanding transmission would enable utilities to tap into diverse regional resources when necessary, providing Americans with more affordable and more reliable power in times of peak demand and generator outages.

I. Generator performance during Winter Storm Fern

Table 1 shows that during Fern's peak demand periods, renewable energy greatly exceeded the output that grid operators had expected and that power markets had paid them to provide, while coal and gas generators fell short. Across the regions served by SPP, MISO, and PJM, wind and solar combined provided over 38,000 megawatts (MW), nearly twice the 21,000 MW of output that the resources are compensated to provide during peak demand periods. In exceeding grid planners' expectations by more than 17,000 MW, wind and solar picked up some of the slack from gas underperforming its accredited capacity by 52,000 MW and coal by 7,000 MW.

Comparing resources' actual output against what grid planners expect and what power markets pay them to provide is the best metric of performance. Across these three regions, wind delivered more than twice its expected output. In MISO, wind and solar combined exceeded the output level they are paid to provide in MISO's capacity market by 14,413 MW, while gas underperformed its accredited output level by 21,515 MW, and coal by 3,000 MW. In SPP, wind and solar exceeded their accredited capacity by 5,675 MW, while gas underperformed by 16,466 MW, and coal by 2,626 MW.

Table 1: Output during Winter Storm Fern peak demand against accredited capacity

SPP+MISO+PJM	Actual MW	Accredited MW	MW Under (-) or Over (+) performance	Output as % of expected
Gas	**114,136**	**166,122**	**-51,986**	**69%**
Coal	**77,556**	**84,494**	**-6,939**	**92%**
Solar	**2,600**	**3,428**	**-828**	**76%**
Wind	**35,796**	**17,679**	**18,117**	**202%**
SPP[1]	**Actual MW**	**Accredited MW**	**MW Under (-) or Over (+) performance**	**Output as % of expected**
Gas	14,837	31,303	-16,466	47%
Coal	17,347	19,973	-2,626	87%
Solar	278	87	191	320%
Wind	10,777	5,293	5,484	204%
MISO[2]	**Actual MW**	**Accredited MW**	**MW Under (-) or Over (+) performance**	**Output as % of expected**
Gas	36,476	57,991	-21,515	63%
Coal	28,887	31,887	-3,000	91%
Solar	376	847	-471	44%
Wind	23,167	8,283	14,884	280%
PJM[3]	**Actual MW**	**Accredited MW**	**MW Under (-) or Over (+) performance**	**Output as % of expected**
Gas	62,823	76,829	-14,006	82%
Coal	31,321	32,634	-1,313	96%
Solar	1,946	2,494	-548	78%
Wind	1,852	4,103	-2,251	45%

Generator outages and derates were primary reasons that fossil-based generators underperformed. Table 2 shows each resource type's outage rate as a percent of its installed capacity[4] during each region's period of peak demand during Winter Storm Fern. In PJM,[5] gas generators were 1.8 times more likely than wind generators to experi-

1 Actual generation during peak divided by accredited capacity from SPP, *2025 SPP Winter Season Resource Adequacy Report*, https://www.spp.org/documents/75520/2025%20spp%20winter%20resource%20adequacy%20report.pdf, at 7

2 Actual generation during peak divided by accredited winter capacity from MISO, *2025 PRA Results*, https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf, at 41

3 Actual generation during peak from PJM, Generation by Fuel Type, https://dataminer2.pjm.com/feed/gen_by_fuel, divided by January 2026 installed capacity from EIA, Preliminary Monthly Electric Generator Inventory, https://www.eia.gov/electricity/data/eia860m/, times PJM accreditation from PJM, ELCC Class Ratings for the 2025/2026 Third Incremental Auction, https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-26-3ia-elcc-class-ratings.pdf

4 EIA, *Preliminary Monthly Electric Generator Inventory: January 2026*, https://www.eia.gov/electricity/data/eia860m/

5 PJM, *January Cold Weather Operations*, https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260205/20260205-item-03---cold-weather-update.pdf, at 44

ence an outage, while coal was 2.7 times more likely. In SPP,[6] the outage rates for gas and coal were 28 and 13 times higher, respectively, than wind; in MISO,[7] outage rates for gas and coal were 4 and 6 times higher than wind.

Table 2: Generator outage rate during WS Fern peak demand by region and fuel type

Outage rate %	Gas	Coal	Wind
SPP	25%	11%	1%
MISO	7%	11%	2%
PJM	12%	18%	7%

This is consistent with fossil generators' underperformance during other recent severe winter-peak-demand periods. Reports and regional analyses by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) have documented that widespread outages and derates of gas generators were the primary causes of reliability disruptions during all severe cold-weather events from 2014-2023, including Winter Storm Elliott in December 2022,[8] Winter Storm Uri in February 2021,[9] the 2018 Bomb Cyclone,[10] the 2018 South Central Cold Snap,[11] and the 2014 Polar Vortex.[12] In particular, gas accounted for 63 percent of unplanned outages and derates during Winter Storm Elliott, and 55 percent during Winter Storm Uri and the 2014 Polar Vortex, while coal accounted for 18-28 percent of outages across those events.

Table 3 presents SPP data showing repeated underperformance by fossil-based generators and overperformance of wind generators during recent winter storms.[13] SPP's market monitor documented that last winter, gas resources averaged the highest outage rate of any fuel type at 25 percent, compared with coal at 17 percent and wind at 14 percent, noting further that "Natural gas outages were fairly correlated with weather events, primarily winter storms as defined by the National Weather Service. Outage causes for these resources reflects their vulnerability with a greater proportion of forced outages caused by fuel supply disruptions, which are common during winter

6 SPP, *Capacity of Generation on Outage*, https://portal.spp.org/pages/capacity-of-generation-on-outage

7 MISO, *Overview of Winter Storm Fern*, https://cdn.misoenergy.org/20260217 RSC Item 05 Winter Storm Fern Report741721.pdf, at 7. MISO only provided a fuel type breakdown for the 17.2 GW of "same-day outages," so those outage rates are used.

8 FERC and NERC, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations*, https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott, at 5

9 FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States*, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16

10 EIA, *January's Cold Weather Affects Electricity Generation Mix in Northeast, Mid-Atlantic*, https://www.eia.gov/todayinenergy/detail.php?id=34632

11 FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf, at 57-58, 96-97

12 NERC, *Polar Vortex Review*, https://www.nerc.com/globalassets/our-work/reports/event-reports/polar_vortex_review_29_sept_2014_final.pdf, at 13

13 Garrett Crowson, *System Operations, January 2024 Winter Storm Gerri*, https://www.spp.org/Documents/71037/ORWG%20Meeting%20Materials%2020240208.zip (file 11 Winter storm Gerri MOPC ORWG.pptx, slides 21-23)

weather events."[14] Correlated outages and derates of gas generators have also played a major role in reliability issues during extreme heat, including the 2022[15] and 2020[16] heat waves in California.

Table 3: SPP table showing performance by fuel type relative to its accredited capacity

Fuel type	Winter Storm Uri	Coal	Wind
Gas	43%	82%	82%
Coal	77%	66%	69%
Wind	100%	350%	235%

PJM now accounts for the repeated widespread outages of fossil generators during peak demand periods in the capacity accreditation it uses to determine generators' capacity market revenue. As a result, gas combustion turbines receive only 67 percent of their nameplate capacity as accredited capacity, comparable to the 60 percent capacity accreditation for offshore wind resources, while gas combined cycle generators are accredited at 78 percent of their nameplate capacity.[17]

Correlated gas generator outages during these events have occurred due to power plant equipment failures, shortages of gas supply due to frozen wellheads, and pipeline failures or constraints. PJM notes that during Winter Storm Fern, nationally there was a 10 billion cubic foot (bcf) per day drop in natural gas production due to frozen gas wells.[18] PJM data also show that during both Uri and Elliott, gas production dropped by around 20 percent nationally, or 20 bcf/day.[19]

II. Increasing dependence on gas generation poses both an economic and a reliability risk

While gas supply interruptions during Fern were not large enough to repeat the rolling blackouts that occurred during Uri and Elliott, ratepayers were not spared an economic hit. PJM notes that "Spot gas prices through this event reached historic levels throughout the eastern U.S. with many hubs trading well over $100/mmbtu with prices in NY and New England approaching $300/mmbtu."[20] These prices are 30–90 times the average price of gas

14 SPP Market Monitoring Unit, *Winter 2025 Resource Adequacy Season Review*, https://www.spp.org/documents/74810/winter%202024-2025%20resource%20adequacy%20season%20review.pdf, at 16

15 Regenerate California, *California's Underperforming Gas Plants*, https://caleja.org/wp-content/uploads/2023/06/2023-Regenerate-Heat-Wave-Report.pdf

16 CAISO, *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

17 PJM, *ELCC Class Ratings for the 2028/2029 Base Residual Auction*, https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/28-29-bra-elcc-class-ratings.pdf

18 PJM, *January Cold Weather Operations*, https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260205/20260205-item-03---cold-weather-update.pdf, at 38

19 *Id.*, at 40

20 *Id.*, at 38

in 2025. As fuel costs are reflected in electric bills, this will translate into billions of dollars in additional costs for homeowners and businesses, on top of billions of dollars in additional costs for the gas they used for heating buildings and other purposes. As gas prices spiked across the Eastern U.S., many generators switched to oil to save money on fuel.

Natural gas prices have always been volatile during severe winter weather, but they are increasingly affected by global events. The ongoing rapid expansion of Liquified Natural Gas exports is tethering the domestic gas price to global prices, exposing ratepayers to geopolitical risks such as Russia's invasion of Ukraine and Iran's ongoing blockade of oil and gas shipping through the Strait of Hormuz. Diversifying energy production provides a valuable hedge against natural gas's price volatility and uncertainty.

III. Coal generators also underperformed during Winter Storm Fern

Coal plants are also susceptible to severe cold and extreme heat. Winter weather can freeze the coal piles at power plants, and frozen rivers can block barge deliveries of coal. Extreme heat or drought can also derate or even knock coal plants offline because their cooling water is too hot, or rivers are too low for coal barges to get through.[21] Coal deliveries via railroad have also been disrupted by rail traffic congestion in some regions.[22] Moreover, all power plants are subject to equipment failures, and failure rates rise in extreme heat and severe cold. Thermal power plants that rely on water to produce electricity are susceptible to frozen pipes. Different types of power plants have different risks, so a diverse generation mix reduces the risk of correlated outages. Wind and solar plants do not need deliveries of fuel or cooling water, and thus are immune to these reliability risks.

Coal units under DOE mandates to continue operating beyond their scheduled retirement performed particularly poorly during Winter Storm Fern, as DOE's own data show in the table below.[23] This poor performance is to be expected for coal plants that were slated for retirement because their equipment has reached the end of its useful life. In many cases their owners have also deferred maintenance and capital expenditures in anticipation of their retirement, further increasing their outage rate.

21 H. Northey and P. Behr, *Severe heat, drought pack dual threat to power plants*, https://www.eenews.net/articles/severe-heat-drought-pack-dual-threat-to-power-plants/

22 A. Larson, *Poor Rail Service Causing "Coal Supply* Crisis," https://www.powermag.com/poor-rail-service-causing-coal-supply-crisis/

23 DOE, *Fact Sheet: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms*, https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms

Table 4: DOE performance data for MISO coal units under DOE mandate

	Nameplate MW	DOE claim for minimum MW output during Fern	Output as % of nameplate
Campbell	1,561	650	42%
Schahfer	847	285	34%
Culley[24]	104	30	29%

The data also confirm that these coal units were not needed to maintain system reliability. The output from these three MISO coal units sum to 965 MW. Data released by MISO show that it had significantly more spare capacity than that throughout the event, and therefore could have met the power demand without these plants.[25] MISO only reached Energy Emergency Alert stage 2 during Winter Storm Fern, which is step 2 out of 5 on its emergency procedures. Steps 3 and 4 involve additional load management, emergency energy purchases, and deploying operating reserves, so MISO had many more tools in its belt before it would have resorted to shedding load in Step 5.

24 DOE indicates its MW output figure for Culley is an average while the MW levels for the other coal units are their minimum output.

25 MISO, *Overview of Winter Storm Fern*, https://cdn.misoenergy.org/20260217%20RSC%20Item%2005%20Winter%20Storm%20Fern%20Report741721.pdf, at 5

IV. Wind and solar generation performed well during Winter Storm Fern

As shown in Table 5, during Winter Storm Fern in January 2026, wind and solar generation provided around 20 percent to 27 percent of the electricity during the peak demand hours in the SPP[26] and MISO[27] grid operating areas in the Midwest. In the Electric Reliability Council of Texas (ERCOT) footprint, wind and solar provided over 15 percent of generation during the peak demand hour on January 26, and 24 percent on January 27.[28]

Table 5: Wind and solar as a share of total generation during WS Fern peak demand

	Total generation on peak	Wind and solar generation on peak	Wind and solar share of total on peak
SPP Jan 24	47,500	9,400	20%
SPP Jan 25	47,000	12,700	27%
ERCOT Jan 26	75,300	11,400	15%
ERCOT Jan 27	75,200	18,200	24%
MISO Jan 26	102,700	23,400	23%
MISO Jan 27	104,500	23,700	23%

Figure 1 below shows how wind and solar contributed during Fern's peak demand periods in SPP. Renewable output was particularly high during SPP's highest demand between January 24 and January 26, as shown on the left side of the chart. Renewables reduced SPP's need for conventional generating capacity during Fern, from nearly 47,500 MW (the highest point of the light blue shaded area on the left side of the chart) to 38,000 MW (where the light blue area meets the dark green area below that point). This 9,437 MW reduction in the need for generating capacity during Winter Storm Fern is worth more than $12 billion at the current cost of generating capacity.[29] MISO realized similar benefits, with wind and solar bringing peak need down from nearly 104,500 MW to 95,200 MW, capacity savings also worth nearly $12 billion at the current cost of capacity.

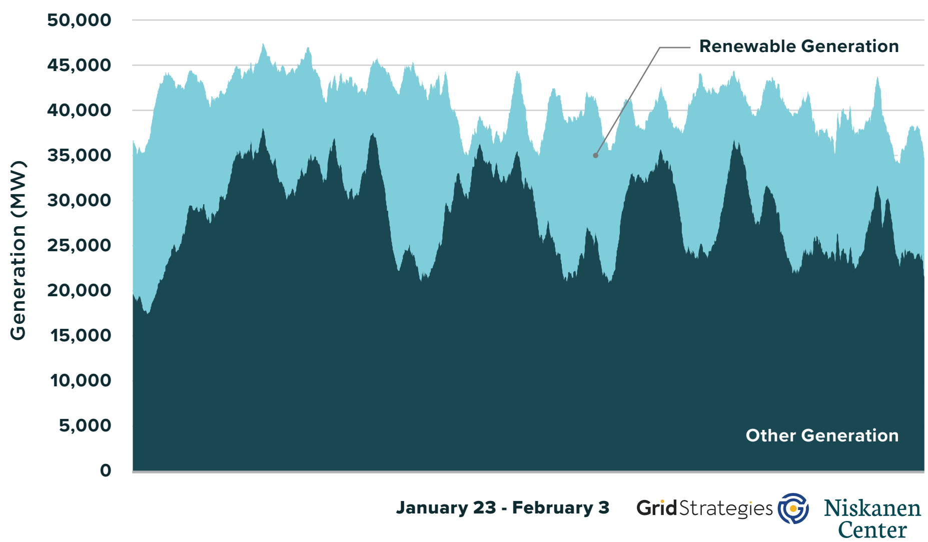
26 SPP, *Generation Mix Historical*, https://portal.spp.org/pages/generation-mix-historical

27 MISO, *Generation Fuel Mix*, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=/MarketReportType:Summary/MarketReportName:Generation%20Fuel%20Mix%20(xlsx)

28 ERCOT, *Interval Generation by Fuel Report*, https://www.ercot.com/files/docs/2026/02/09/IntGenbyFuel2026.xlsx

29 Using a cost of capacity of $1,280/kW, per PJM, *CONE, Operating Parameters for Net EAS, and Net CONE Updates*, https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250822-special/cone-operating-parameters-for-net-eas-and-net-cone-updates.pdf, at 4

Figure 1: Renewable and other generation in SPP during Winter Storm Fern



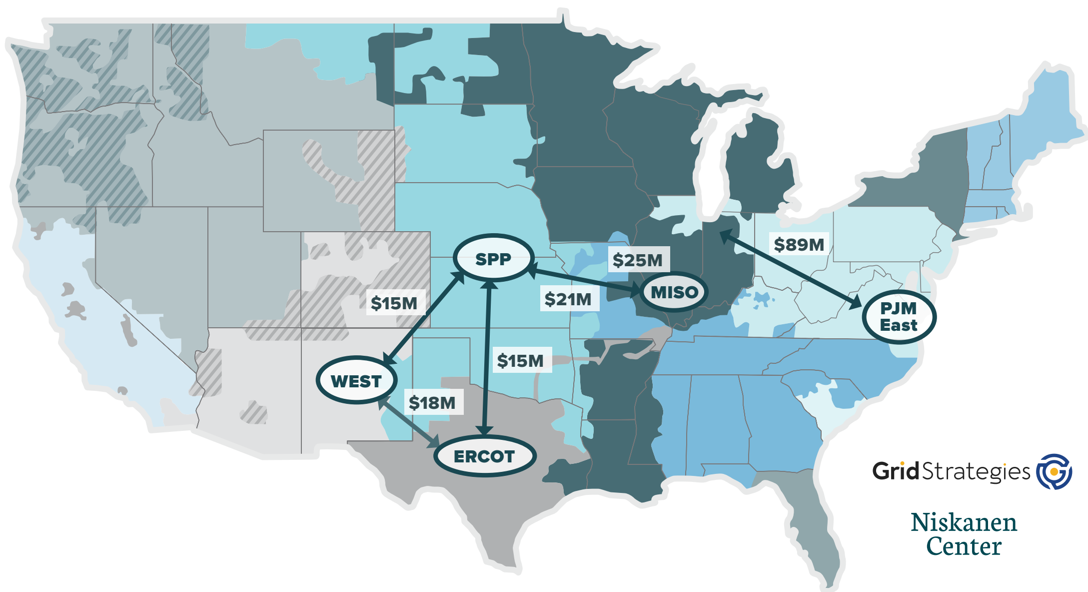
Renewable resources contributed significantly in other regions as well. The 572 MW of the Vineyard Wind offshore project that were operational while the plant was still under construction provided a 75 percent average capacity factor (actual output as a percent of maximum output) during Winter Storm Fern,[30] holding down power prices in New England as the price of natural gas spiked. The 132 MW South Fork offshore wind project near Long Island operated at a 52 percent capacity factor in January 2026, also reducing power prices during Winter Storm Fern. As discussed above, these levels of output are comparable to the performance of coal and gas generators during Fern. If more offshore wind capacity had been allowed to come online by now, the benefit would have been even greater.

30 M. Gallucci, *Offshore wind showed up big during the East Coast's brutal cold*, https://www.canarymedia.com/articles/offshore-wind/offshore-wind-showed-up-big-east-coast

V. The economic and reliability benefits of expanding transmission

Increased electricity transmission capacity would have protected consumers from localized electricity price volatility during Fern. Pricing disparities occurred due to regional differences in the timing of peak electricity demand, generator outages, and spikes in the price of natural gas, as noted. Expanding transmission allows a region that is experiencing a shortfall of low-cost electricity supply to import from other regions. The map in Figure 2 shows the value ratepayers could have received for the period January 23 to February 3, 2026, by expanding transmission ties between each of the following regions by one gigawatt (GW), which is comparable to the capacity of one new transmission line. The savings were calculated from the differences in power prices among the MISO,[31] ERCOT,[32] PJM,[33] SPP,[34] and Western energy markets,[35] and then reduced for price elasticity on both ends.[36]

Figure 2: Value during Winter Storm Fern from expanding transmission ties by 1 GW



31 MISO, *Real-Time 5-Min ExAnte LMPs*, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AReal-Time%205-Min%20ExAnte%20LMPs%20(xlsx)&t=10&p=2&s=MarketReportPublished&sd=desc

32 ERCOT, *Historical RTM Load Zone and Hub Prices*, https://www.ercot.com/mp/data-products/data-product-details?id=NP6-785-ER

33 PJM, *Real-Time Five Minute LMPs*, https://dataminer2.pjm.com/feed/rt_fivemin_hrl_lmps

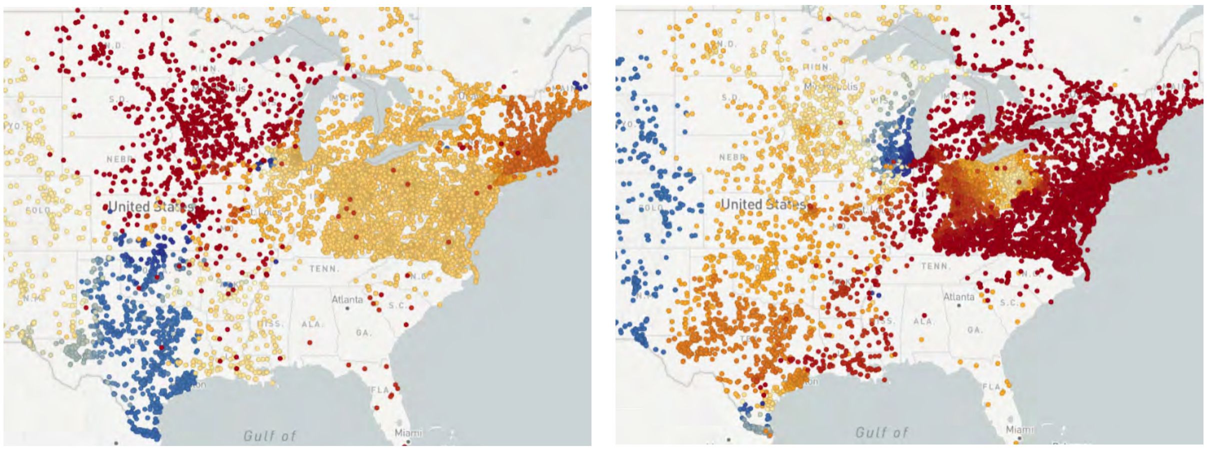
34 SPP, *LMP By Location*, https://portal.spp.org/pages/rtbm-lmp-by-location

35 Grid Status, N*odal Analysis REEVES_1_REEVES3GNODE*, https://www.gridstatus.io/nodes/loc_caiso_f87af1bfde1b8851?time_filter=2026&dataset=caiso_lmp_real_time_5_min

36 J. Kemp *et al.*, *Electric transmission value and its drivers in United States power markets*, https://www.researchsquare.com/article/rs-3957695/v1, at 10

The left map in Figure 3 shows a snapshot of these locational power prices on January 23 as the cold was moving into the Central U.S., while the right map shows power prices once the cold had reached the Eastern U.S. on January 25.[37] Red dots indicate high prices, blue dots indicate low prices. On January 23, additional transmission could have delivered low-cost electricity to MISO from SPP, ERCOT, and PJM, while on January 25 additional transmission could have delivered power to the East Coast from MISO and western PJM.

Figure 3: Differences in power prices during Winter Storm Fern



January 23, 2026, 4:30 PM ET **January 25, 2026, 4:30 PM ET**

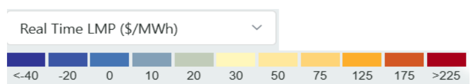


FIgure 4 shows that throughout Winter Storm Fern, there were large differences in the price of electricity between western PJM (Northern Illinois) and eastern PJM (Virginia). Once the cold moved eastward on January 24, power prices were persistently higher in eastern PJM, so additional transmission could have delivered low-cost power from western PJM. In past events the prevailing flows and pricing patterns were reversed, as when Winter Storm Uri hit the middle of the country but spared the coasts.[38] Other events such as Winter Storm Elliott saw power flows change as the weather systems moved over time.[39] In part because it is bidirectional, transmission expansion acts like an insurance policy against the effects of severe weather, as a region that is spared in one weather event will likely be affected by another event in the future. For example, expanded transmission between Texas and the Southeast could have kept the lights on for customers in the Southeast during Elliott,[40] while the same connections could have kept the heat on for Texans during Uri,[41] providing more than $1 billion in value.

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37 Grid Status, *Nodal Map*, https://www.gridstatus.io/map

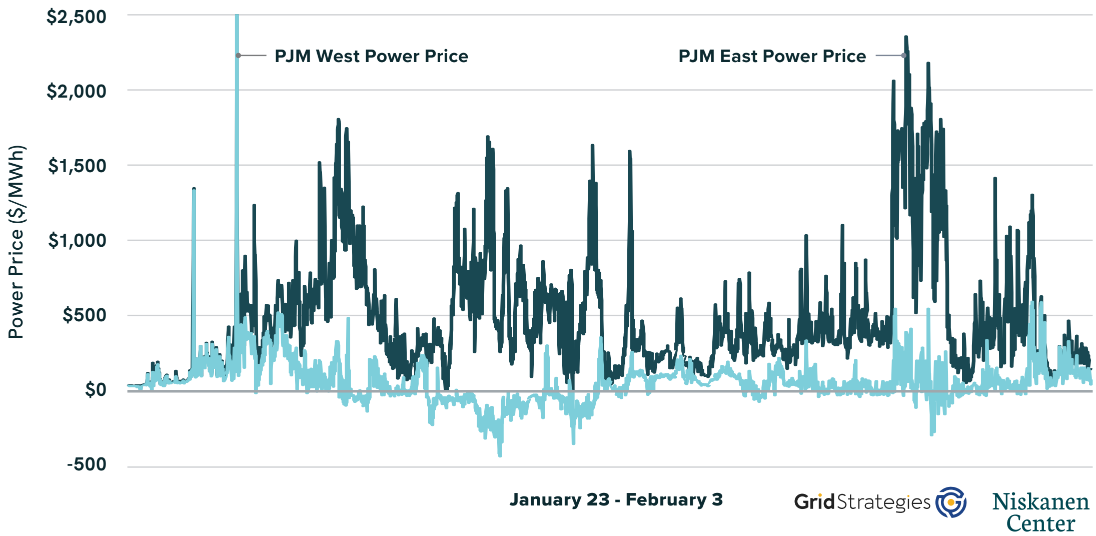
38 M. Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

39 M. Goggin and Z. Zimmerman, *The Value of Transmission During Winter Storm Elliott*, https://acore.org/wp-content/uploads/2023/02/ACORE-The-Value-of-Transmission-During-Winter-Storm-Elliott.pdf

40 *Id.*

41 M. Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

Figure 4: Power prices in eastern and western PJM during Winter Storm Fern



Wind and solar projects in some areas faced significant curtailment during Fern because there was not enough transmission capacity to deliver power to customers at peak demand. For example, the curtailed wind and solar generation in SPP alone could have saved MISO consumers nearly $37 million had there been enough transmission to deliver it.[42]

However, most of transmission's value is from providing consumers with more reliable and lower-cost power, regardless of energy type. If there is enough transmission to aggregate electricity supply and demand over a larger area, the total need for generating capacity is less than the sum of the parts from each individual utility. This is due to variation in when regions experience peak demand or supply shortfalls. A stronger transmission grid protects against localized generator outages and fuel supply disruptions that increase price by allowing imports from other regions with surplus lower-cost generation.

Figure 5 shows how, for the severe weather event shown in each row, different regions experienced their peak need at different times.[43] Weather events tend to be at their most severe in a limited geographic area, and they also move over time, so imports from neighboring regions that are less affected are a key tool for cost-effectively keeping the lights on during severe weather. By making the grid bigger than the weather, interregional transmission reduces the need for each region to overbuild generating capacity for these outlier events.

42 SPP, *VER Curtailments*, https://portal.spp.org/pages/ver-curtailments

43 M. Goggin *et al.*, *Quantifying a Minimum Interregional Transfer Capability Requirement*, https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf, at 4

Figure 5: Differences in the timing of peak need among regions during 2014 Polar Vortex, 2018 Bomb Cyclone, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022

Each region's net load during severe weather events, as a percent of that region's maximum net load across all nine years

	ERCOT	SPP	MISO S	TVA	MISO N	PJM	NYISO	ISO-NE	Carolinas	SOCO	Florida
1/17/2014 7 AM ET	58%	60%	74%	86%	75%	100%	68%	64%	88%	87%	60%
1/17/2018 10 AM ET	60%	67%	100%	81%	61%	70%	61%	63%	56%	85%	61%
1/18/2018 6 AM ET	58%	50%	65%	76%	55%	66%	51%	55%	63%	100%	79%
2/15/2021 10 AM ET	100%	99%	83%	61%	69%	63%	56%	59%	58%	68%	55%
12/23/2022 6 PM ET	68%	87%	88%	99%	86%	85%	60%	56%	88%	91%	65%
12/24/2022 6 AM ET	63%	87%	87%	91%	77%	85%	49%	50%	100%	95%	66%

The Grid Strategies analysis in the Figure 5 data above found that over a nine-year period, building enough transmission to aggregate supply and demand across these subregions of the Eastern U.S. and Texas would have reduced the need for generating capacity by 137 GW, which at the current cost of generating capacity would provide more than $175 billion in savings.[44] Said another way, the 137 GW in savings is roughly twice the capacity required to meet the expected increase in electricity demand from data centers, so expanding interregional transmission can provide more than enough spare capacity to maintain reliability while meeting load growth.

Variation across these regions in the timing of peak load and conventional generator failures drove more than 87 percent of the capacity benefit of expanding interregional transmission ties in the analysis above, with diversity in renewable resource output accounting for only 13 percent of the benefit.[45] As gas generation grows to provide a larger share of our peaking capacity, interregional transmission connections to counteract regional generator outages or disruptions to the gas supply will become more valuable.

CONGRESS AND FERC SHOULD STEP IN TO CORRECT MARKET FAILURES AND PROTECT CONSUMERS

A more interconnected and flexible grid would be better positioned to maintain reliability and limit price spikes when the next winter storm hits. Expanding transmission is also essential to reliably accommodate electricity demand growth by 1) reducing the need for regions to overbuild generating capacity for outlier events; and 2) by enabling the interconnection of new loads and the new generators that will power them. Under direction from Congress in the Fiscal Responsibility Act of 2023, NERC's Interregional Transfer Capability Study identified 35

44 PJM, *CONE, Operating Parameters for Net EAS, and Net CONE Updates*, https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250822-special/cone-operating-parameters-for-net-eas-and-net-cone-updates.pdf, at 4

45 M. Goggin *et al.*, *Quantifying a Minimum Interregional Transfer Capability Requirement*, https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf, at 5

GW of "prudent additions" to interregional transmission that are needed to maintain reliability.[46] Notably, that study was published in 2024, so the identified transmission need predates nearly all of the recent upswing in load growth projections.

FERC should, of its own accord or under the direction of Congress, establish an interregional planning requirement, or a minimum interregional transfer capacity requirement. FERC's February 2026 report to Congress[47] on the NERC study declined to recommend a capacity requirement. FERC noted that the NERC study did not include an economic assessment, though many assessments of the economic value of transmission have been published, including by national labs.[48] Economic analysis by Grid Strategies showed that the 35 GW of prudent additions that NERC identified in its report would be highly net beneficial.[49]

FERC should also require markets to standardize assessments of and compensation for high voltage direct current (HVDC) transmission technology,[50] which is well-suited for long-distance and interregional power transfer. Standardization would facilitate the interconnection of these lines and provide a revenue stream for the capacity and grid-stability services these lines can provide.

Congress should establish a narrow and clear federal siting authority for high-capacity interstate transmission, reflecting federal interests in the interstate and interregional flow of electricity.

Interregional transmission projects take years to complete, though. In the interim, state and federal policymakers and regulators should pursue practical "no regrets" upgrades that increase transfer capability while larger projects are developed.[51] Grid-enhancing technologies, strategically sited batteries, and reconductoring existing lines with advanced conductors can be deployed quickly to increase transfer capability.

46 NERC, *Interregional Transfer Capability Study*, https://www.nerc.com/globalassets/initiatives/itcs/itcs_final_report.pdf, at xiii, xvii

47 FERC, *FERC Sends Interregional Transfer Capability Report to Congress* https://www.ferc.gov/news-events/news/ferc-sends-interregional-transfer-capability-report-congress

48 J. Kemp *et al.*, *Electric transmission value and its drivers in United States power markets*, https://eta-publications.lbl.gov/sites/default/files/2025-09/task_1_empricalvalue_and_drivers_formatted.pdf

49 M. Goggin and Z. Zimmerman, *NERC's Recommended Grid Expansion Would Save Consumers Billions*, https://gridstrategiesllc.com/wp-content/uploads/GS_NRDC_NERCs-Recommended-Grid-Expansion-Report54.pdf

50 R. Allen and R. Levine, *Unlocking HVDC: How Congress can enable a more resilient grid*, https://www.niskanencenter.org/how-congress-can-enable-a-more-resilient-grid/

51 Niskanen Center, *Niskanen comments on Department of Energy's Speed to Power RFI*, https://www.niskanencenter.org/niskanen-comments-on-department-of-energys-speed-to-power-rfi/

VI. What is the outlook for grid reliability, and what should be done about it?

Electricity demand is increasing, though there is considerable uncertainty about how quickly it will grow. NERC's 2025 Long Term Reliability Assessment likely overstates the risk of generation shortfalls, as Grid Strategies documented in a recent report.[52] NERC's report likely underestimates the addition of new generating resources and may overstate growth in electricity demand because it is based on utility projections that in some cases are now out of date. The report also does not account for imports from neighboring grid operators due to diversity among regions in the timing of peak demand and generator outages, which as discussed earlier have played a key role in keeping the lights on during severe weather events.

The primary solution to reliably meeting load growth is to let markets work and to respect utility planning and state regulatory processes. Electricity markets are inherently self-correcting as they send price signals to increase supply when demand is growing faster than supply. Permitting obstacles that block market entry for new low-cost resources that increase the diversity of the generation mix, and mandates that block market exit for uneconomic and underperforming coal generation disrupt market signals and increase the costs to consumers. Renewable and storage account for 92 percent of the resources trying to connect to the grid.[53] Incentivizing more gas generation that is dependent on the same gas supply fields, while suppressing investment in renewable and storage projects, exposes consumers to more risk of correlated outages and price volatility. Diversity builds a more economic, reliable, and resilient generation mix. A diverse generation mix, and transmission that taps into regional diversity, are the best solutions for ensuring Americans have affordable and reliable power in the face of extreme weather, wars, and other uncertainties that are certain to occur.

52 A. Brooks *et al.*, *Review of NERC's 2025 Long-Term Reliability Assessment*, https://gridstrategiesllc.com/wp-content/uploads/FINAL-2025-LTRA-Review.pdf

53 J. Rand *et al.*, *Queued Up: 2025 Edition*, https://emp.lbl.gov/publications/queued-2025-edition-characteristics