THE VALUE OF TRANSMISSION DURING WINTER STORM ELLIOTT

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As families gathered for the holidays at the end of last year, in many regions they were joined by an unwelcome guest: bitter cold. From December 22-26, 2022, Winter Storm Elliott brought near-record low temperatures and wind chills across much of the Central and Eastern U.S. In the power sector, record winter electricity demand coincided with the large-scale loss of fossil power plants due to equipment failures and interruptions to natural gas supplies. Parts of the Southeast experienced rolling blackouts as electricity demand exceeded supply, while power prices spiked in many regions.

Additional transmission capacity would have protected consumers from those blackouts and price spikes by bringing in power from other regions. The large differences in power prices across regions as Winter Storm Elliott moved west-to-east across the country, plus the economic cost of outages in parts of the Southeast, indicate the value a stronger power grid could have provided during the event. This report finds that in some areas modest investments in interregional transmission capacity would have yielded nearly $100 million in benefits during the 5-day event, while most areas could have saved tens of millions of dollars. The following map summarizes the benefits a hypothetical one gigawatt (GW) expansion of interregional transmission capacity could have provided in different areas.

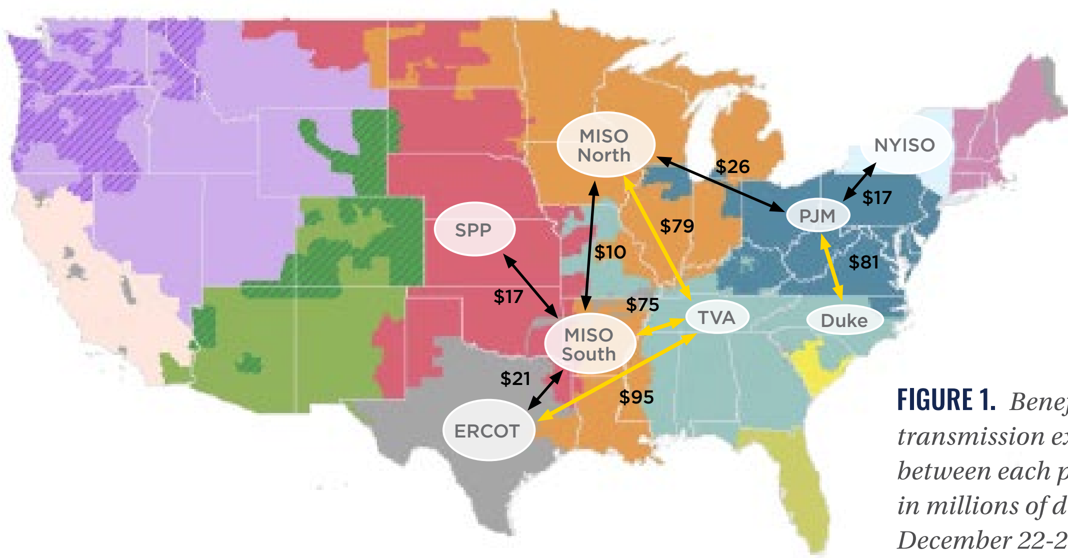


FIGURE 1. *Benefit of 1 GW transmission expansion between each pair of regions, in millions of dollars, December 22-26, 2022*

Additional transmission into the Duke/Progress utility area in the Carolinas and the Tennessee Valley Authority (TVA) would have provided the largest benefit by alleviating customers' rolling outages. The value of additional transmission into these regions was calculated by using power prices at TVA's interface with MISO as well as Duke's interface with PJM during hours without outages, and an assumed Value of Lost Load of $9,000/MWh during time periods with outages.[1] For all other regions in our analysis the value of transmission was calculated based entirely on the difference in hourly power prices, as these regions did not experience rolling outages.

1 https://pubs.naruc.org/pub/2AF1F2F3-155D-0A36-3107-99FCBC9A701C, at 3, footnote 7.

As shown in Figure 2 below, a one GW transmission line between the Electric Reliability Council of Texas (ERCOT) and TVA would have provided nearly $95 million in value, mostly to TVA customers. That adds to the nearly $1 billion in value that line, flowing in the other direction, would have provided Texans suffering through outages during Winter Storm Uri in February 2021.[2] Similarly, one GW of additional transmission capacity from PJM into the Duke/Progress operating areas in the Carolinas could have provided those customers with electricity valued at over $80 million by helping to keep the lights on.

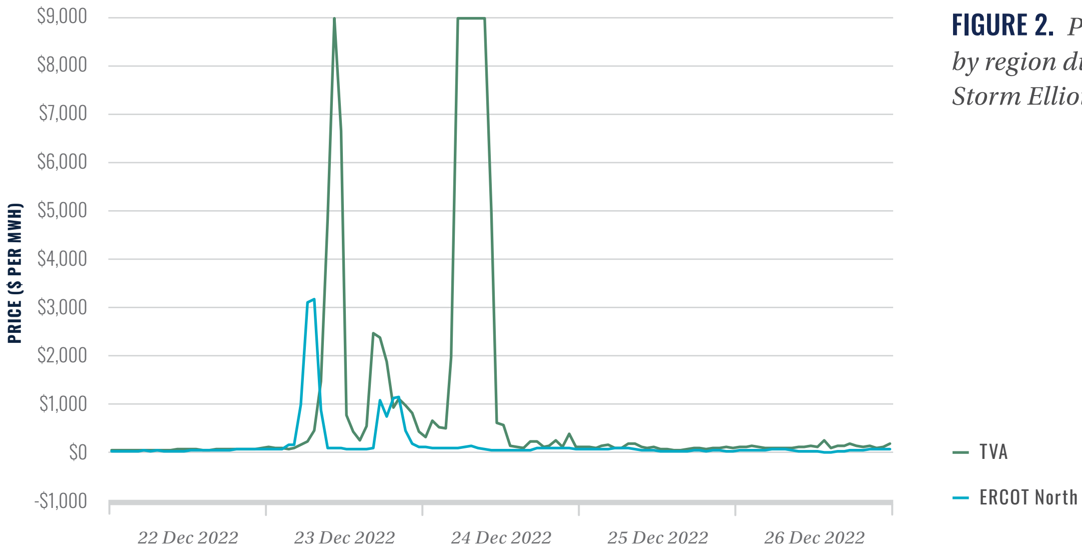
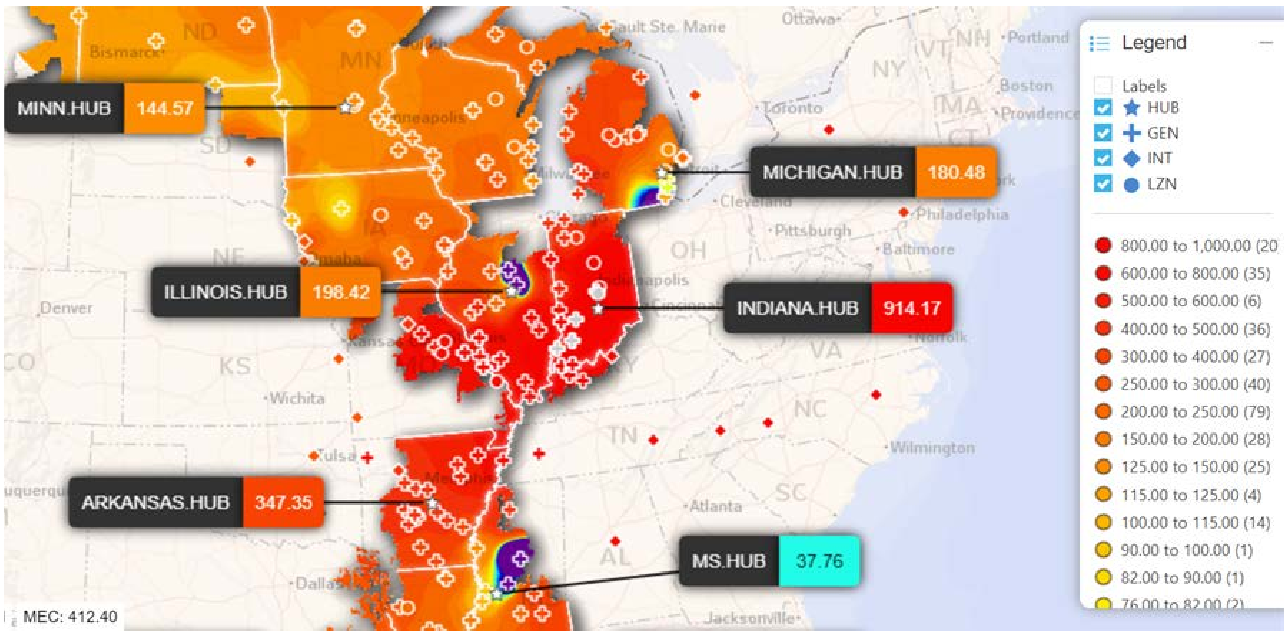


FIGURE 2. *Power prices by region during Winter Storm Elliott*

2 https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

One GW lines from neighboring Louisiana or Illinois, parts of the Midcontinent Independent System Operator (MISO), into TVA could have provided around $75 million or $79 million in value, respectively. As an influx of polar air caused record low wind chills, it also drove up wind energy output across the MISO, Southwest Power Pool (SPP), ERCOT, and PJM grid operating areas, driving power prices down. Unfortunately, there was insufficient transmission to deliver that wind energy to areas that needed it. It appears that on Christmas Eve morning, wind plants in parts of western MISO were forced to curtail their output while the lights went out in neighboring TVA. At several points in time that morning power prices were slightly negative in western MISO, likely reflecting the curtailment of wind energy. The large west-to-east gradient in Locational Marginal Prices (LMPs) within MISO at one point on the morning of December 24 is shown below.

FIGURE 3. *MISO LMPs on December 24, 2022 at 8:00 am, Eastern Time*



Additional transmission within MISO and SPP would have enabled additional low-cost wind energy to reach customers who needed it, saving nearly $9 million within MISO and $6 million within SPP, and could have helped to alleviate outages in TVA. Congestion and seams issues between MISO and PJM, and between MISO and the Southeast, appear to have caused the localized pockets of negative prices seen in Mississippi, Illinois, and Michigan in the map above.

As shown in Figure 4 below, power prices across parts of MISO North were very low or even slightly negative the morning of December 24, reflecting seams congestion and possibly the curtailment of wind energy.

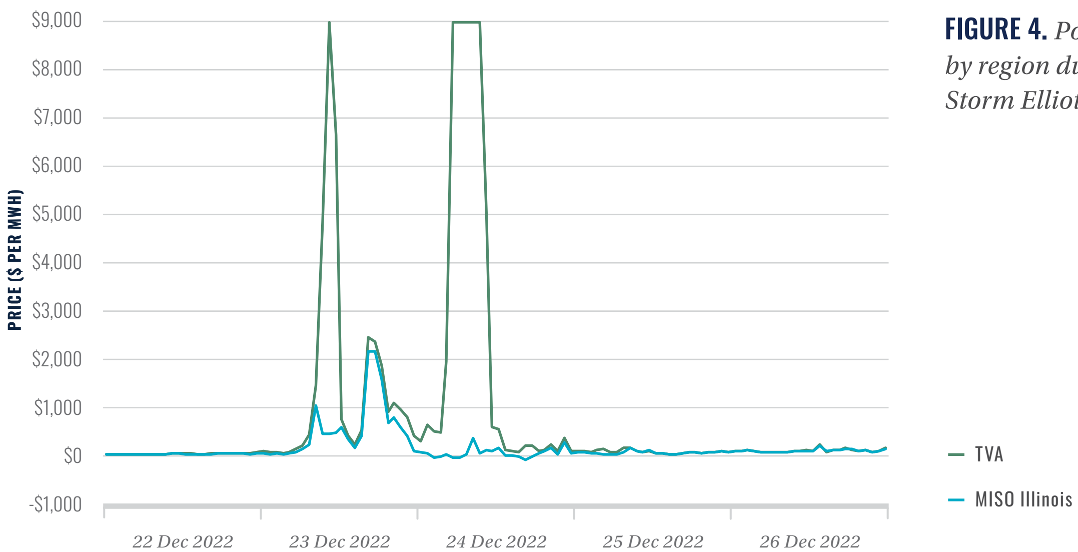


FIGURE 4. *Power prices by region during Winter Storm Elliott*

Over December 22-26, each GW of additional transmission capacity across the MISO-PJM seam in Illinois, between MISO's Illinois hub and the Commonwealth Edison zone in PJM, would have provided around $27 million in economic value. Both regions would have benefited significantly, reflecting that over the course of the event prices and power flows reversed as the extreme cold moved from west to east across the country. As shown below, power prices spiked in MISO on the morning of December 23, while it was not until that evening and the next morning that the extreme cold reached much of PJM.

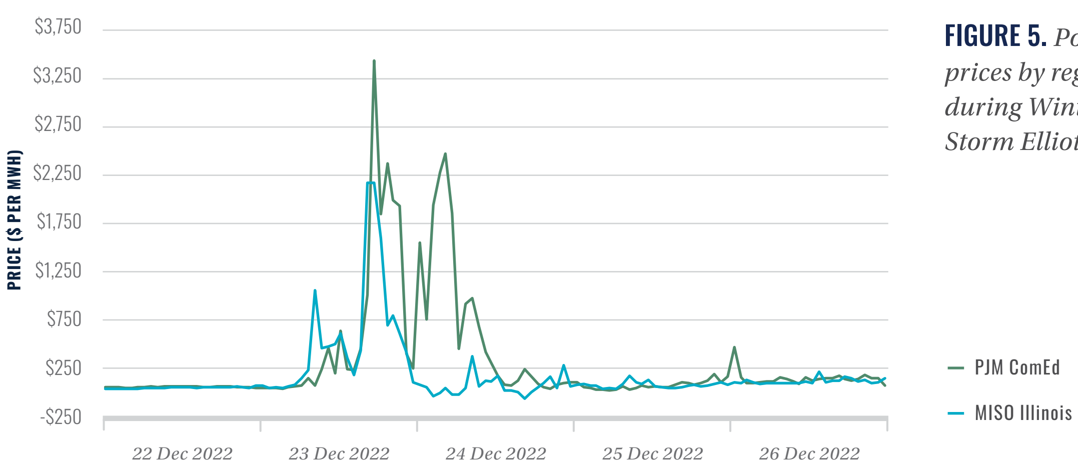
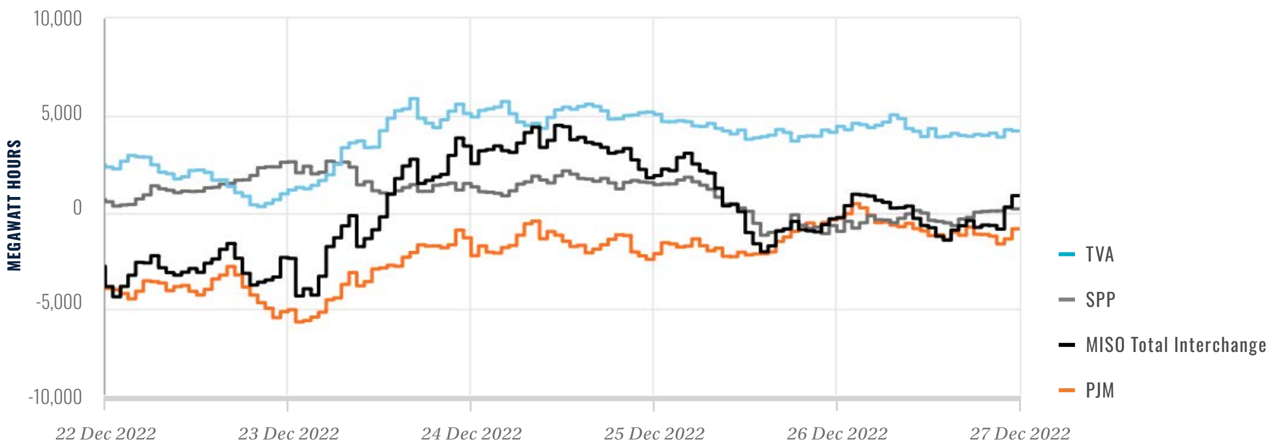


FIGURE 5. *Power prices by region during Winter Storm Elliott*

MISO swung from initially importing nearly 4,500 MW as it and SPP dealt with the worst of the extreme cold, to exporting nearly 4,500 MW later in the event after the extreme cold moved farther east, as shown below. Bidirectional flips in power flows and prices have occurred during past events as the area of most severe weather migrates over time.[3]

FIGURE 6. *MISO electricity interchange with neighboring balancing authorities 12/22/2022–12/26/2022, Eastern Time (positive = export, negative = import)*



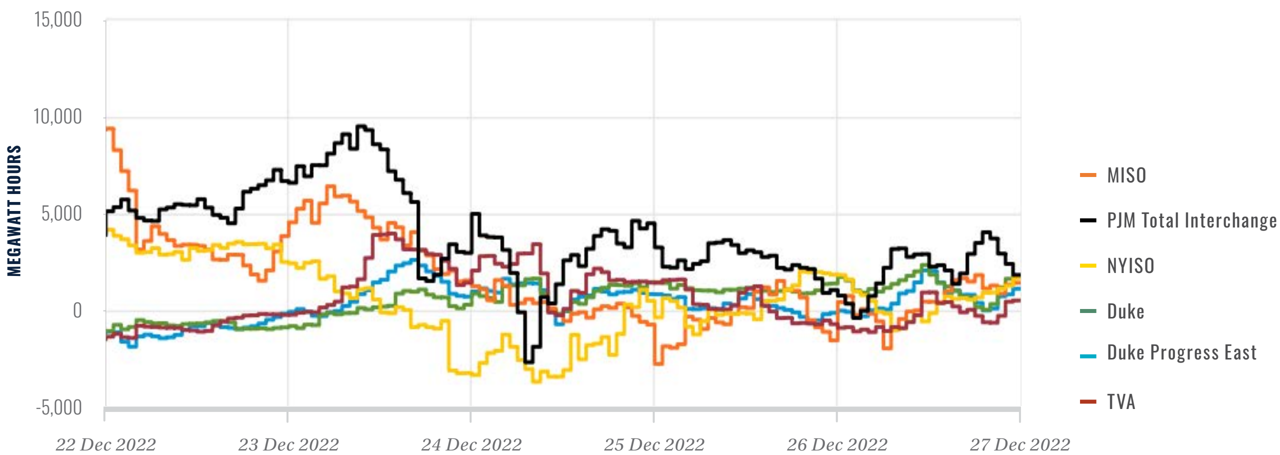
Similarly, a region that primarily exports power during one severe weather event is likely to benefit from imports during another event. While Winter Storm Elliott had the largest impact on the Southeast, Winter Storm Uri primarily affected the Central U.S. and had minimal impact on the Eastern U.S. As a result, expanded ties between Texas and the Southeast would have helped keep the heat on in Texas during Winter Storm Uri and in the Southeast during Winter Storm Elliott. Other studies have confirmed that expanded ties between ERCOT and the Southeast have large reliability value, due to diversity in weather patterns and generation resources and because the main Texas grid lacks strong transmission ties to other states.[4]

3 https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

4 https://www.esig.energy/wp-content/uploads/2022/07/EStvIG-Multi-Value-Transmission-Planning-report-2022a.pdf.

In less than 24 hours between December 23 and the morning of December 24, PJM also flipped from exporting nearly 10,000 MW to importing more than 2,500 MW, as shown in Figure 7. Much of that swing involved transactions with New York. While PJM power prices spiked during the evening of December 23 and the morning of December 24, prices in New York remained relatively low because the extreme cold had not yet reached the Northeast, so additional transmission capacity could have allowed additional electricity exports to PJM and other regions facing the brunt of the storm. Over the course of the 5-day event, additional transmission between PJM and NYISO would have saved nearly $17 million.

FIGURE 7. *PJM electricity interchange with neighboring balancing authorities 12/22/2022–12/26/2022, Eastern Time (positive = export, negative = import)*



One GW of additional transmission capacity within PJM, between Commonwealth Edison in Illinois and the Dominion zone in Virginia, also would have yielded nearly $27 million in savings during the event. Similarly, expanding ties between the Louisiana hub in MISO South and the Illinois hub in MISO North would have saved around $10 million, with those benefits fairly evenly split between those zones. As indicated in the chart below, this occurred because power prices peaked at alternating times between MISO South and North, reflecting the movement of the storm and the lack of strong transmission ties between those MISO subregions.

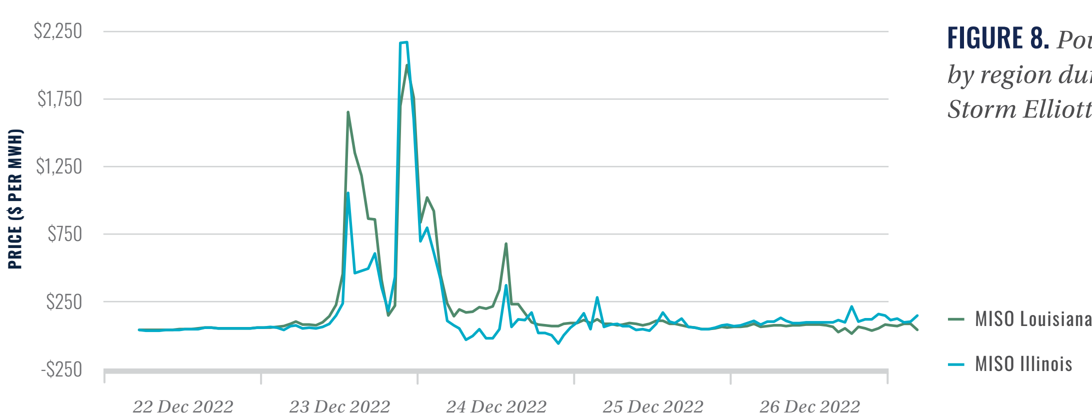


FIGURE 8. *Power prices by region during Winter Storm Elliott*

Additional transmission also would have helped to alleviate significant congestion among ERCOT, SPP, and MISO. An additional GW connection between ERCOT and the Louisiana hub in MISO South would have saved over $20 million over those five days, with the benefits nearly evenly split between ERCOT and MISO customers. As shown below, one GW of expanded transmission between SPP's South hub and the MISO Louisiana hub would have saved around $17 million.

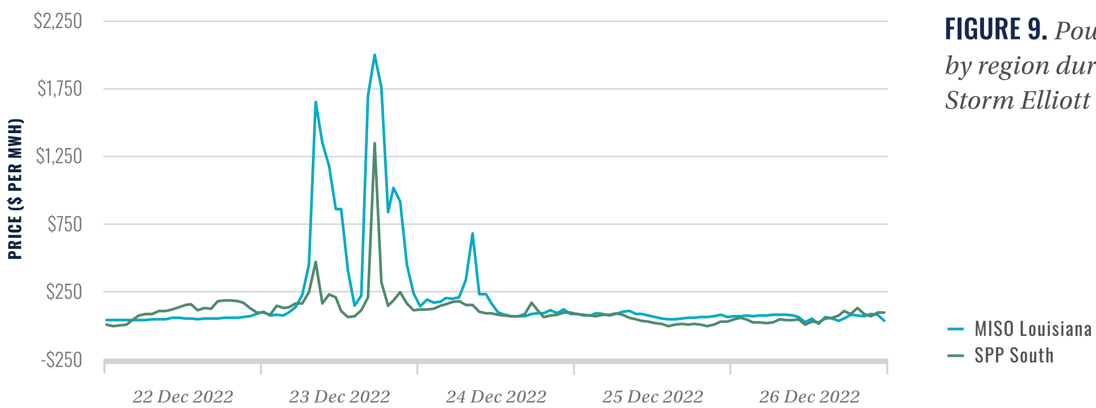


FIGURE 9. *Power prices by region during Winter Storm Elliott*

Table 1 summarizes the benefits of expanding transmission across the 12 regional and interregional interfaces discussed above.

TABLE 1. *Benefit of 1 GW transmission expansion between each pair of regions, December 22-26, 2022*

Region-to-region interface (primary exporting region listed first)	Benefit of 1 GW transmission expansion
ERCOT North-TVA	$95 million
PJM Dominion-Duke/Progress intertie	$81 million
MISO North-TVA	$79 million
MISO South-TVA	$75 million
PJM ComEd-PJM Dominion	$27 million
MISO North-PJM ComEd	$26 million
ERCOT North-MISO South	$21 million
SPP South-MISO South	$17 million
NYISO- PJM Dominion	$17 million
MISO North- MISO South	$10 million
Western MISO-MISO North	$9 million
Western SPP-SPP South	$6 million

Making the grid bigger than the weather

Transmission is becoming increasingly valuable as climate change causes more frequent and more severe extreme weather events. Changes in the generation mix are also making interregional transmission more valuable. A primary cause of the outages and price spikes during Elliott appears to have been the loss of gas generators due to a systemic failure of the natural gas system, as was also the case during Uri and other recent cold snaps, including the 2014 and 2019 Polar Vortex events, the 2018 Bomb cyclone and South Central U.S. cold snaps, and the 2011 Southwest outages. As the press reported after Elliott:

On Dec. 23, US natural gas production suffered its worst one-day decline in more than a decade, with roughly 10% of supplies wiped out because of wells freeze-offs. Output was as low as 84.2 billion cubic feet on Saturday, a 16% decline from typical levels, before a slow recovery started, according to BloombergNEF data based on pipeline schedules… Most of the output loss was seen in the Northeastern Appalachia basin, where supplies plunged to the lowest level since 2018. US natural gas futures posted gains on Tuesday as supplies remained severely constrained by freeze-offs. Supplies from Appalachia to the Tennessee Valley and the Midwest more than halved from typical levels, according to pipeline flow data compiled by BloombergNEF.[5]

Equipment failures across all types of power plants also played a significant role in electricity shortfalls during Elliott, as was the case in previous cold snaps. At one point on December 23,

5 Gerson Freitas, Jr. et al., *America's electrical grid barely escaped a calamity as massive storm exposes a vulnerable natural-gas infrastructure*, Fortune (Dec. 27, 2022, 2:36 PM EST), https://fortune.com/2022/12/27/america-electrical-grid-barely-escaped-a-calamity-as-massive-storm-exposes-a-vulnerable-natural-gas-infrastructure/.

2022, TVA lost more than 6,000 megawatts of power generation or nearly 20% of its load at the time, including three large coal units.[6] Preliminary data for MISO,[7] PJM,[8] and SPP[9] show all fuel types were taken offline, though gas makes up the largest share of lost capacity.

Investigations are underway to determine which generators failed during Winter Storm Elliott, and why. Regardless of which energy sources failed, strengthening transmission is an essential part of the solution for preventing future outages due to all types of severe weather, including extreme heat, cold, and drought. Extreme weather events tend to be most severe in relatively small areas, so stronger transmission ties to neighboring regions can be a lifeline to keep homes warm and people safe. Transmission ties cancel out local fluctuations in the weather that affect electricity demand, primarily due to heating and cooling needs, and supply, including changes in wind and solar output as well as failures of conventional power plants due to extreme weather. A few weeks before Winter Storm Elliott, nearly all panelists at a Federal Energy Regulatory Commission (FERC) workshop endorsed expanding interregional transmission as an insurance policy against severe weather events that affect all energy sources.[10]

Most transmission planning processes do not account for severe weather events in the net benefit calculations that determine whether grid investments move forward.[11] This is despite the fact that recent analysis by Lawrence Berkeley National Laboratory indicates that half of transmission's value accrues in only 5% of hours, typically when the power system is being stressed by extreme weather.[12] Policy changes are therefore needed to account for transmission's value as an insurance policy for grid resilience, such as through a minimum interregional transfer requirement as was discussed at FERC's December 2022 workshop.

Making the grid bigger than the weather will become even more important as wind and solar provide a larger share of our electricity.[13] Just as transmission helps cancel out the localized impact of severe weather events, it also captures geographic diversity in wind and solar output across larger regions. This reduces the variability of wind and solar output and ensures a higher level of dependable output during periods of peak need. Transmission also captures complementary output profiles between wind and solar resources in different regions on a daily and seasonal basis. For example, transmission will allow the Southeast to export solar power to the Midwest during the day and during summer months, and then import wind energy from the Midwest at night and during the winter.[14]

6 Dave Flessner, *Chattanooga area hit with 1-minute power outages as cold weather forces rolling blackouts*, Chattanooga Times Free Pres (Dec. 24, 2022, 9:42 AM), https://www.timesfreepress.com/news/2022/dec/24/power-outages-tfp/.

7 https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

8 https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx.

9 SPP, "December 2022 Winter Storm Elliott."

10 https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission

11 https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf, at 36, 82.

12 https://emp.lbl.gov/news/regional-and-interregional-transmission-have

13 https://www.ferc.gov/media/panel-3-christopher-clack-vibrant-clean-energy-llc.

14 https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf.

Methodology

The transmission benefits in this report were primarily calculated by comparing Locational Marginal Prices (LMPs) within Regional Transmission Organizations (RTOs) and at interfaces with non-RTO areas in each hour during December 22-26, 2022.[15] The Cimarron River LMP node in western SPP and LMPs at the NSP/OTP interface in western MISO were used to represent prices in the wind-heavy western parts of those RTOs, while all other calculations were based on prices at the major RTO hubs and interfaces listed in Table 1 above. As noted above, a $9,000/MWh value was assumed for deliveries into TVA[16] and Duke/Progress[17] during their rolling outages.

The analysis conservatively used hourly average LMPs instead of prices at 5-minute intervals, as current practices for scheduling transactions between regions include market seam inefficiencies that limit the ability to use transfers to address short-term fluctuations in price. To test the impact of this assumption, the hourly results were compared against results using 5-minute prices for the SPP West-SPP South and NYISO-PJM ties, which indicated that using 5-minute prices would increase the calculated value of transmission by 5.4% in SPP and 4.1% for the NYISO-PJM tie.

This understatement of savings is about equal to the estimated overstatement of savings because this analysis did not account for increases in LMPs in exporting regions due to the 1 GW increase in demand that would be caused by the expansion of transmission ties. Our 2021 analysis found comparably modest increases in prices in exporting regions due to that effect, as the price increase on the delivering end of a line is generally much smaller than the price decrease on the receiving end because the electricity supply curve slopes much more steeply upward when demand is high.[18] Because those two factors roughly offset each other, they are not accounted for in this analysis.

15 MISO LMP and TVA interface price data obtained from https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AReal-Time%20Final%20Market%20LMPs%20(csv)&t=10&p=0&s=MarketReportPublished&sd=desc; PJM LMP, NYISO interface, and Progress/Duke interface price data at the Roxboro intertie obtained at https://dataminer2.pjm.com/feed/rt_hrl_lmps; SPP LMP data from https://marketplace.spp.org/pages/rtbm-lmp-by-location#%2F2022%2F12%2FBy_Day; and ERCOT North LMPs from https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=886632075.

16 https://www.wbir.com/article/news/local/tva-artic-blast-rolling-blackouts-east-tennessee/51-9fac437b-6cce-40eb-a0ce-650be785b1de indicates the TVA outages on December 23 extended from 9:31 AM to 11:43 AM, while on December 24 they extended from 4:51 AM to 10:31 AM.

17 https://ncpolicywatch.com/2023/01/04/several-crises-malfunctions-at-duke-energy-led-to-rolling-blackouts-on-christmas-eve-utility-officials-tell-state-regulators/ indicates Duke/Progress outages occurred from 6:14 AM to 4 PM on December 24.

18 https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf, at 20-21.