QUANTIFYING A MINIMUM INTERREGIONAL TRANSFER CAPABILITY REQUIREMENT

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FOR

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BY

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INTRODUCTION

This report demonstrates a straightforward method by which a minimum interregional transfer capability requirement can be set based on objective historical data. Applying this approach to historical data from the last decade indicates that a minimum interregional transfer capability requirement equivalent to 20-25% of peak load conservatively approximates the need for and reliability benefit of interregional transmission in all regions.

The minimum transfer requirement can be calculated based on how transmission accesses geographic diversity across regions in the timing of peak demand, generator output, and correlated generator outages. The methodology compares the capacity need if sources of electricity supply and demand are aggregated across the Interconnect, which accounts for how geographic diversity in hourly electricity demand and supply patterns decreases the need for capacity, against the larger sum of the component regions' stand-alone capacity needs. Interregional transmission reduces the amount of generating capacity that is needed to achieve the same level of reliability, mostly by canceling out the weather's localized and short-lived impacts on electricity supply and demand.

That geographic diversity benefit should set the interregional transfer capability requirement. This reflects that a certain megawatt (MW) amount of interregional transmission allows the component regions to achieve the same level of reliability with that many fewer MW of generating capacity by accessing geographic diversity. This method was applied to nine years of historical data, which captures the largest reliability threats over the last decade: Winter Storm Elliott in December 2022, Winter Storm Uri in February 2021, the South Central event in January 2018, and the Polar Vortex event in January 2014.

That analysis indicates that the Federal Energy Regulatory Commission specifying a default minimum interregional transfer capacity requirement in the range of 20-25% of peak load would conservatively approximate the need for and reliability benefit of interregional transmission in all regions. This report also outlines a similar methodology a region can use if it seeks to demonstrate its need for transfer capacity differs from that default. However, a specific default transfer capacity requirement applied uniformly to all regions is likely superior to more complex region-specific analytical approaches due to 1. Significant intractable uncertainty about factors including future weather and climate patterns, the generation mix and location, load patterns, and the geography of gas supply and demand and pipeline networks, 2. The fact that future severe weather and other extreme events will never perfectly replicate past events, 3. Challenges that arise from individual regions using different methodologies and assumptions to determine their interregional transfer capacity needs, and 4. The fact that all regions within an Interconnect are inherently affected by power flows resulting from the balancing of electricity supply and demand across all other regions in the Interconnect.

A straightforward requirement applied uniformly to all regions reflects that interregional transmission functions like an insurance policy against unexpected events, in that it is

impossible to precisely predict when, where, or for what that insurance policy will be needed, but over the long term all regions will be affected by such an event and will benefit from that interregional transfer capacity. Favoring an elegant uniform requirement over more complex methods is consistent with the use of default standards to approximate other reliability and resilience needs, like the 1-day-in-10-year Loss of Load Expectation standard that serves as the foundation for resource adequacy planning in most regions. A minimum interregional transfer capability requirement set in the range of 20-25% of peak demand would ensure high levels of reliability and resilience in the face of evolving threats to the bulk power system. Transmission is bidirectional so it provides a capacity benefit to both interconnected regions, and transmission is largely immune to the correlated outages that affect many types of generation. As a result, expanding interregional transmission can increase electric reliability and resilience more effectively and at lower cost than increasing the redundancy of generating resources. Europe has set a similar target for each country's interregional transfer capacity to cover 15% of its installed generating capacity by 2030.[1] In the U.S. installed capacity is about 67% greater than peak load2 and increasing, so Europe's 15% installed capacity requirement is roughly equivalent to a transfer capability requirement for 25% of peak load.

1 European Commission, "Electricity interconnection targets," available at https://energy.ec.europa.eu/topics/infrastructure/electricity-interconnection-targets_en

2 1,241,578 MW installed capacity over a peak demand of approximately 742,000 MW = 1.6733, per installed capacity for 2021 https://www.eia.gov/electricity/data/eia860/ and recent peak demand https://www.eia.gov/electricity/gridmonitor/expanded-view/custom/pending/ElectricityOverview-2/edit

RESULTS

A minimum interregional transfer capacity requirement can be calculated from publicly available hourly electricity supply and demand data. This methodology was applied to 9 years of historical data for ERCOT and the U.S. portion of the Eastern Interconnect, a time period that captures the largest reliability threats over the last decade: Winter Storm Elliott in December 2022, Winter Storm Uri in February 2021, the South Central cold weather event in January 2018, and the Polar Vortex event in January 2014. The results of this analysis are shown below.

TABLE 1. *Reduced capacity need from interregional transmission in Eastern and ERCOT Interconnections*

Reduction in capacity needs, as a share of peak load	21%
Reduction in capacity needs, in MW	137,146
Economic value of reduced capacity needs	$113 billion

Aggregating electricity supply and demand across ERCOT and the U.S. portion of the Eastern Interconnect over this time period reduced the peak need for capacity by 137,146 MW,[3] with the vast majority of this benefit accruing from geographic diversity within the Eastern Interconnect. This geographic diversity benefit equates to 20.99% of the sum of the peak loads of the component regions over the last five years, supporting the creation of a default minimum requirement for all regions somewhere in the range of 20-25% of peak load. The reduced capacity need from interregional transmission can be translated to $113 billion in economic savings based on the avoided capital cost of an equivalent amount of gas combustion turbine capacity.[4]

This geographic diversity benefit results from the timing mismatch in when regions experience peak demand and reductions in generator output, typically because individual severe weather events do not affect all regions equally and move over time. As summarized in the table below, and shown in more detail in the maps in Appendix A, when some regions are experiencing generation shortfalls during a severe weather event, other regions tend to have abundant spare capacity available. Each row in the table shows the net load[5] of each region during one hour of a severe weather event, as a percent of the maximum net load that region experienced across all nine years of the analysis. Regions at or near 100% and shown in red are experiencing their maximum shortfall in generation supply, while regions with low percentages shown in green tend to have abundant spare capacity at that point in time. By aggregating regions with spare

3 This refers to MW of unforced generating capacity, generating capacity that has been derated to account for outages and derates during peak periods, and thus equates to theoretical capacity that is perfectly dependable.

4 Conservatively using an assumed $785/kW cost of a frame combustion turbine from U.S. Energy. Info. Admin., *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022* (March 2022), available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf and the conservative assumption that a new combustion turbine offers 95% of its nameplate capacity as dependable capacity value. To be conservative, ongoing fixed O&M costs for maintaining that gas capacity were also not accounted for.

5 As explained in Appendix B, "net load" is defined as electricity demand minus renewable output plus conventional generator forced outages, to reflect the impact of conventional generator forced outages and changes in renewable output on the need for other capacity.

capacity with regions experiencing shortfalls, interregional transmission is an effective tool for countering the localized reliability impacts of extreme events.

TABLE 2. *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%

This analysis was based on data for the years 2012-2015 and 2018-2022. As documented in Appendix B, the period 2012-2015 was included because data tracking hourly conventional generator forced outage rates by NERC regional entity are available for that time period from Murphy et al. 2018-2022 was chosen because that time period captures three severe weather events (the 2018 South Central event and Winter Storms Uri and Elliott) for which FERC-NERC reports or other public data sources tracking hourly generator forced outages are available, and because EIA Form 860 began to track Balancing Authorities' hourly generation by fuel type in July 2018.

Our analysis also evaluated how several sensitivities affected the need for and reliability benefit of interregional transmission, relative to the results presented above which are repeated in bold in the table below. First, we found that the need for interregional transmission is only slightly lower if diversity benefits within the Eastern Interconnect are evaluated without accounting for diversity benefits with ERCOT. Second, we found that renewable output diversity is currently a small contributor to the total reliability benefit of interregional transmission, confirming that geographic diversity in electricity demand and conventional generator correlated outages drive more than 87% of the need for a minimum interregional transfer capability requirement. These results are presented in the following table, and were derived using the same general methodology described above and documented in Appendix B.

TABLE 3. *Reduced capacity need from geographic diversity as a share of peak load, under different assumptions*

	With Renewables	Without Renewables
With ERCOT	20.99%	18.35%
Without ERCOT	18.25%	14.42%

In addition to this analysis of the Eastern Interconnect and ERCOT, Grid Strategies previously conducted analysis for the U.S. portion of the Western Interconnect that examines geographic diversity in demand and renewable output. Grid Strategies presented analysis on behalf of the American Clean Power Association at the Commission's December 2022 workshop[6] indicating that in 2021, aggregating demand and renewable output across the Western Interconnect reduced peak net load by 14% or 19,400 MW, relative to the sum of individual Balancing Authorities' peak net loads.

This is a conservative estimate of the total geographic diversity benefit in the West, as it does not account for geographic diversity in correlated conventional generator outages, even though it has been publicly reported that Winter Storms Elliott, Uri, and the cold snap that caused the 2011 Southwest outages did cause parts of the West to experience high forced outage rates. Geographic diversity in correlated outages of conventional generators was not included in that analysis as Murphy et al.'s 2012-2015 dataset tracks outages at the NERC Regional Entity level, so forced outage rates are reported uniformly for all of WECC, precluding analysis of geographic diversity in conventional generator forced outage rates within that region.

Based on localized forced outage rates observed in parts of the West during recent events, as well as geographic diversity in forced outages observed in the Eastern Interconnect, it is likely that the West sees at least a 5-10% additional benefit from geographic diversity in conventional generator forced outages. As a result, 20-25% of peak load is a conservative estimate of the total geographic diversity benefit of aggregating supply and demand in the Western Interconnect.

These results indicate a uniform minimum interregional transfer requirement of 20-25% of peak load for all parts of the Eastern, Western, and ERCOT Interconnections would conservatively approximate the need for and reliability benefit of interregional transmission. As explained above, a universal default requirement based on objective data offers many advantages over more complex region-specific analyses, and these results indicate a single universal requirement in the range of 20-25% of peak load is a conservative approximation of the need in all regions. If a region wants to conduct a more complex analysis to justify a different requirement, the next section discusses minimum criteria for inputs and methodology that FERC should require for such an analysis.

These results are almost certain to be a conservative underestimate of the value of and need for interregional transmission for several reasons. First, hourly forced outage data is not publicly

6 See https://www.ferc.gov/media/panel-3-opening-statement-michael-goggin-grid-strategies-acpa and https://www.ferc.gov/media/panel-3-michael-goggin-grid-strategies-acpa

available for 2018-2022, unlike 2012-2015, as explained in Appendix B. Due to a lack of data, it was conservatively assumed that forced outages were at the same uniform rate (3% for NYISO and ISO-NE, and 5% for all other regions) for regions for which information on forced outages during the cold snap events was not available, and for all regions in all hours outside of the three major cold snaps. This greatly understates the actual geographic diversity in forced outages rates across these regions seen in the 2012-2015 data.

In addition, our analysis does not attempt to model specific interregional power flow needs because future events will not exactly replicate the relatively small sample of events observed over the last decade. However, because power flows often cross multiple regions during such an event and flows to and from larger regions may cross smaller regions, it is more likely for peak power flows into and across some regions to be greater than that region's pro rata share of the Interconnect-wide diversity benefit. As a result, setting each region's requirement as a share of its peak load is more likely to understate than overstate the transmission need in some regions.

The net load analysis of the Western Interconnect is also likely to be conservative as it is based on only one year of data. Analysis over a longer time horizon would likely indicate a larger need and reliability benefit from interregional transmission in the West, as extreme events tend to drive the transmission need and more such events are captured by a longer time horizon.

Finally, the above analysis was based entirely on historical data to keep it founded in incontrovertible objective data, given the inherent uncertainty with projections of the future generation mix and load patterns. However, multiple trends are further coupling electricity supply and demand to the weather, further increasing the value of transmission for tapping into geographic diversity that mitigates the impact of localized weather events. The largest trend in the generation mix over the last 15 years has been the increasing penetration of gas. Multiple cold snap events over that period have shown gas generators are more prone to correlated outages during cold weather than other fuel sources. Peak winter electricity demand coincides with peak demand for gas to meet building heating demand, straining gas supply and pipeline capacity, particularly when supply from gas fields is reduced due to wellhead freeze-offs.[7]

The growth of wind and solar generation is also increasing the impact of localized weather on electric supply, though wind and solar output tend to be negatively correlated during most extreme weather events, increasing the chance that one resource will be available if the other is not.[8] Finally, electrifying heating will further tie electricity demand to the weather and increase electricity demand during extreme cold weather events, further increasing the value of transmission for tapping into geographic diversity that helps cancel out localized weather impacts.

7 A drop in fuel supply to gas generators in at least some affected regions appears to have been a major factor in all of the cold weather electricity reliability events discussed in this report. For example, see the FERC-NERC reports for Winter Storm Uri (https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and) and the 2018 South Central cold weather event (https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf), the NERC report for the 2011 Southwest outages (https://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/SW_Cold_Weather_Event_Final.pdf), the NERC report on the 2014 Polar Vortex (https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf) as well as press reports on Winter Storm Elliott (https://fortune.com/2022/12/27/america-electrical-grid-barely-escaped-a-calamity-as-massive-storm-exposes-a-vulnerable-natural-gas-infrastructure/)

8 For example, wind output has been high during most recent cold snap events, while solar output is often high during summer high pressure heat dome events that often coincide with low wind output but high electricity demand.

As a result, the Commission may want to set the default minimum transfer capability requirement at or above the high end of the 20-25% range, as the 21% of peak load requirement calculated from conservative analysis of data from the last decade likely understates the need going forward.

Methodology for Regions Proposing to Deviate from the Default Minimum

As explained above, a straightforward default transfer capacity requirement applied uniformly to all regions is likely to be superior to more complex analytical approaches developed by each region, due to intractable uncertainty in key inputs into the analysis and challenges that arise from regions using different methodologies and assumptions to determine their interregional transfer capacity needs. However, this section offers a method by which a region can calculate a different requirement if it believes its needs significantly differ from the default minimum requirement. FERC establishing minimum requirements for the assumptions and methods used in such an analysis, and particularly requiring that such an analysis look across the Interconnect, will help ensure that any analyses conducted by regions are compatible.

For geographic scope, FERC should require that regions look at geographic diversity in load, generator output, and generator forced outage rates across the Interconnect. This geographic scope reflects the physical reality that all regions within an Interconnect are inherently affected by power flows resulting from the balancing of electricity supply and demand across all other regions in the Interconnect. For example, during Winter Storm Uri, SPP was importing power from MISO which was importing from PJM, while during Winter Storm Elliott the Southeast was importing from MISO which was importing from Canada and other regions. The power system is a network of interdependent regions, so looking at a small number of regions in isolation misses the benefits of aggregation across a larger area.

For chronological scope, FERC should require a region to use enough historical data to capture extreme events that tend to drive the long-term need for capacity. For example, this could include a requirement that the region use data for at least the last 10 years, but that time period could be expanded to ensure that at least one severe event (as indicated by an anomaly in peak load, temperature, etc.) in each region is included in the dataset.

While the default requirement presented above was calculated solely based on historical data to keep the calculation straightforward and incontrovertible, if a region proposes to add complexity by doing analysis to justify deviating from that default, it should be required to account for expected future trends in the resource mix and load patterns.[9] On the demand side, this should account for the impacts of climate change[10] and increasing electrification on hourly patterns of electricity demand. On the supply side, historical rates of conventional generator correlated outage rates by fuel type could be applied to the expected future generation mix. Existing renewable output profiles can be scaled up using statistical techniques that account for the inherent geographic diversity from adding new resources, or the output from additions of wind and solar capacity can be even more accurately modeled using synthetic hourly resource profiles.[11] The future generation mix in that region and across the Interconnect can be projected based on inputs like the 10-year outlooks in NERC's annual Long-Term Reliability Assessment,[12] with reasonable assumptions for the expected completion rate for planned resources. Utility

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9 FERC could make this requirement consistent with the requirements it sets in its pending rulemaking on Regional Transmission Planning and Cost Allocation, available at https://ferc.gov/media/rm21-17-000.

10 To conduct this analysis, planners could use inputs such as this 50-year historical dataset of hot and cold snaps that has been adjusted for the impacts of climate change to develop a forward projection.https://www.osti.gov/servlets/purl/1885888

11 For example, see https://www.nrel.gov/grid/wind-integration-data.html

12 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf

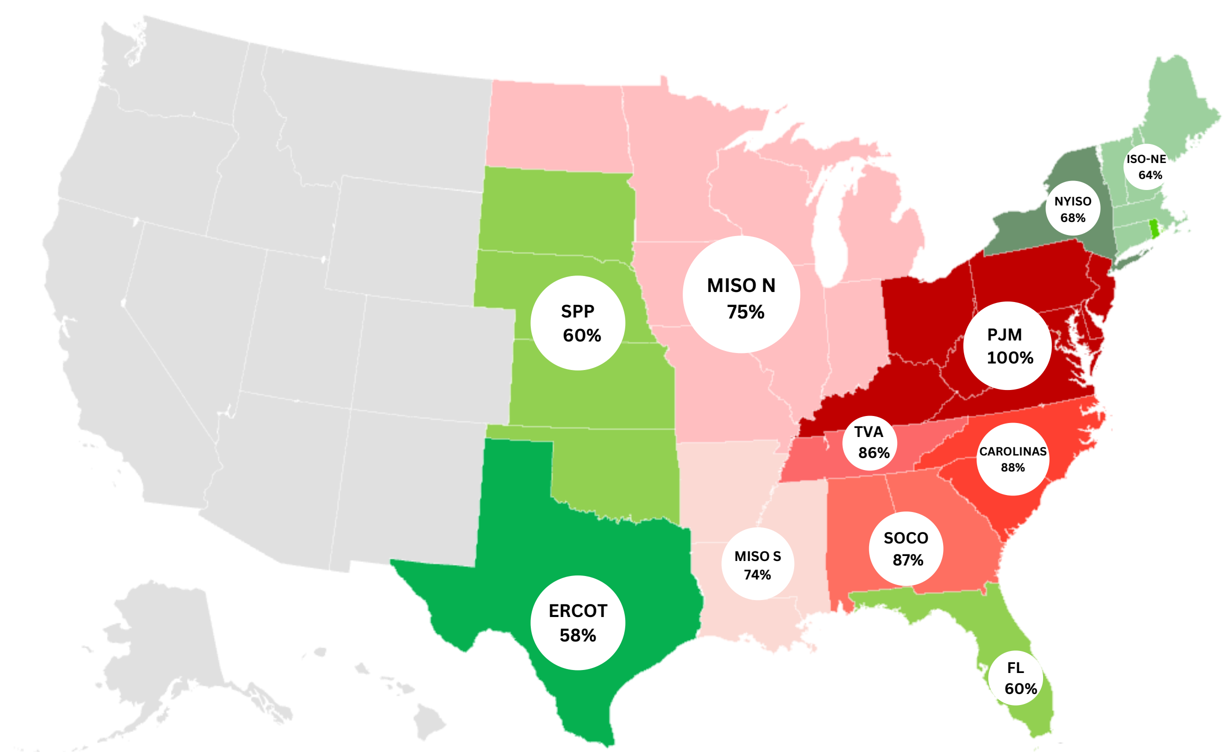
Integrated Resource Plans and utility and state carbon and renewable targets should also be accounted for, where they exist. Regions should be required to file their analysis justifying a different requirement in a contested proceeding at FERC, where intervenors and FERC staff should be given discovery rights that allow them to critically review the model and input assumptions.

APPENDIX A

MAPS OF NET LOAD DIVERSITY DURING SEVERE WEATHER EVENTS

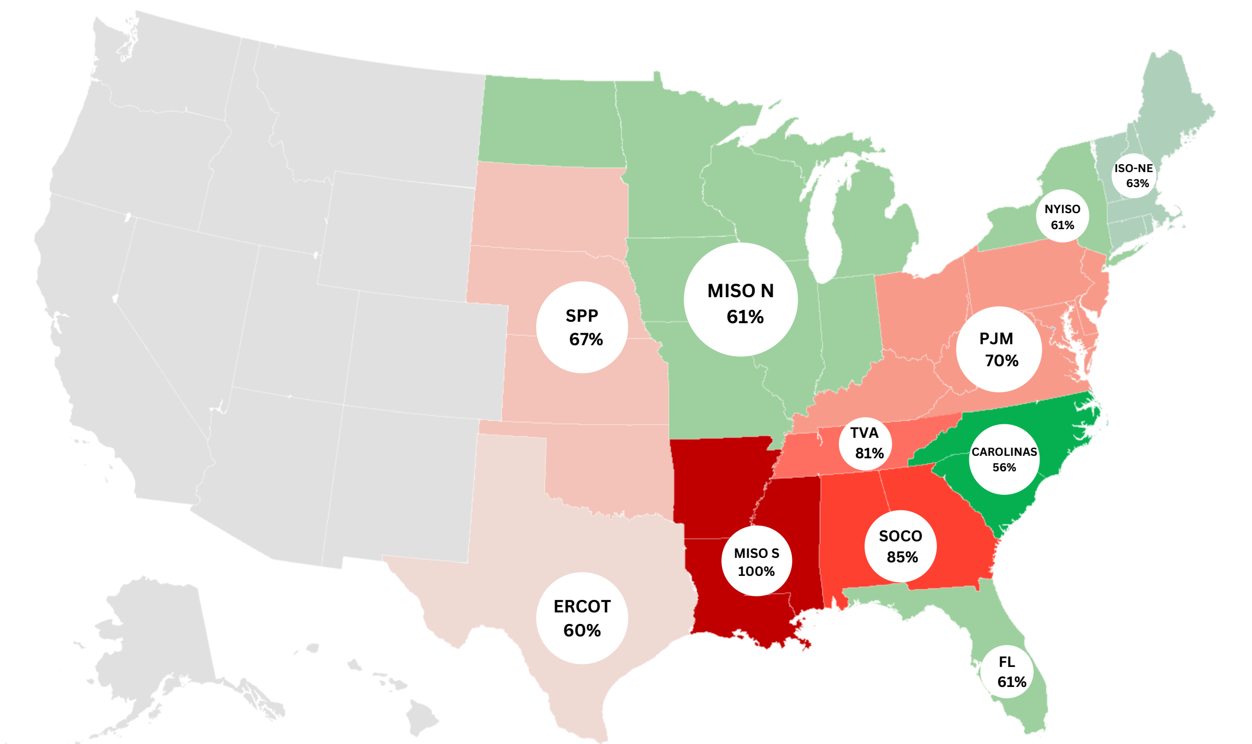
As explained above, geographic diversity benefits result from the timing mismatch in when regions experience peak demand and reductions in generator output, typically because individual severe weather events do not affect all regions equally and move over time. As summarized in the maps below, when some regions are experiencing generation shortfalls, other regions tend to have abundant spare capacity available. Each map shows the net load (defined as electricity demand - renewable output + conventional generator forced outages) of each region during one hour of a severe weather event, as a percent of the maximum net load that region experienced across all nine years of the analysis. Regions at or near 100% and shown in red are experiencing their maximum shortfall in generation supply, while regions with low percentages shown in green tend to have abundant spare capacity at that point in time.[13] By aggregating regions with spare capacity with regions experiencing shortfalls, interregional transmission is an effective tool for countering the localized reliability impacts of severe weather events.

2014 POLAR VORTEX EVENT, JANUARY 17, 2014, AT 7 AM ET

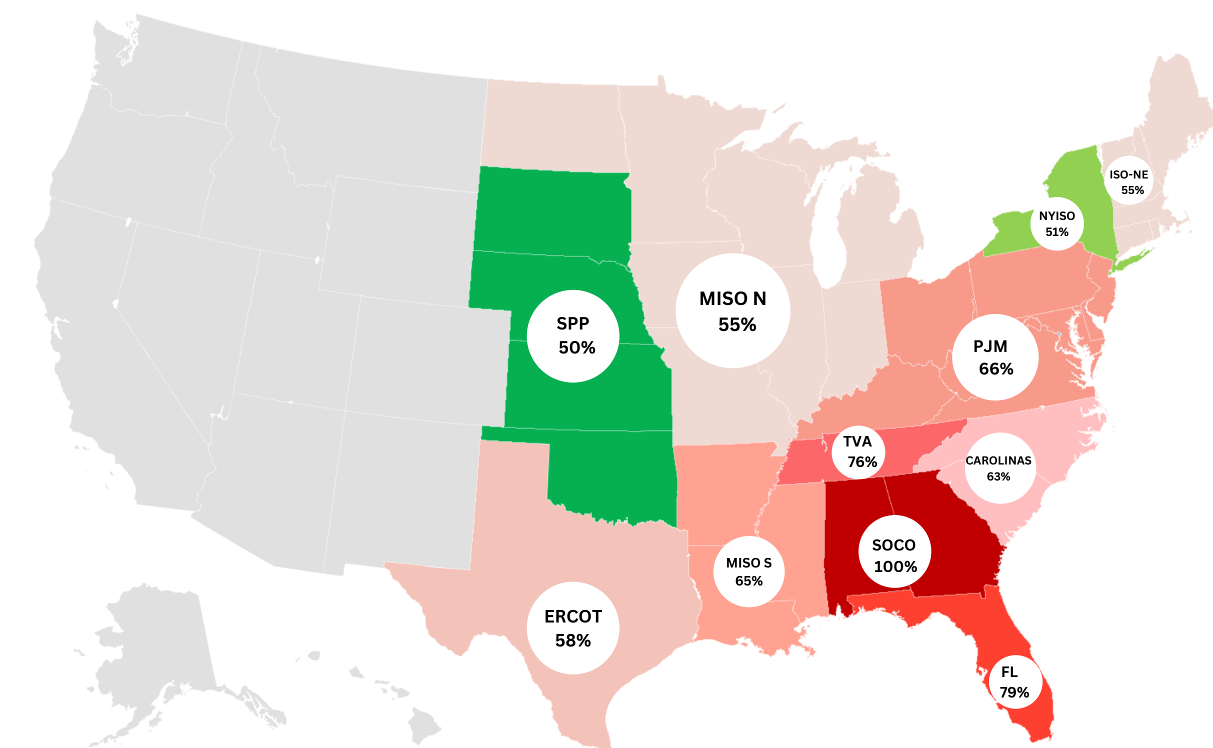


13 These maps approximate the boundaries of grid operators and other regions to the nearest state border for graphical simplicity. The analysis was conducted on data for each grid operator and thus reflects their actual boundaries.

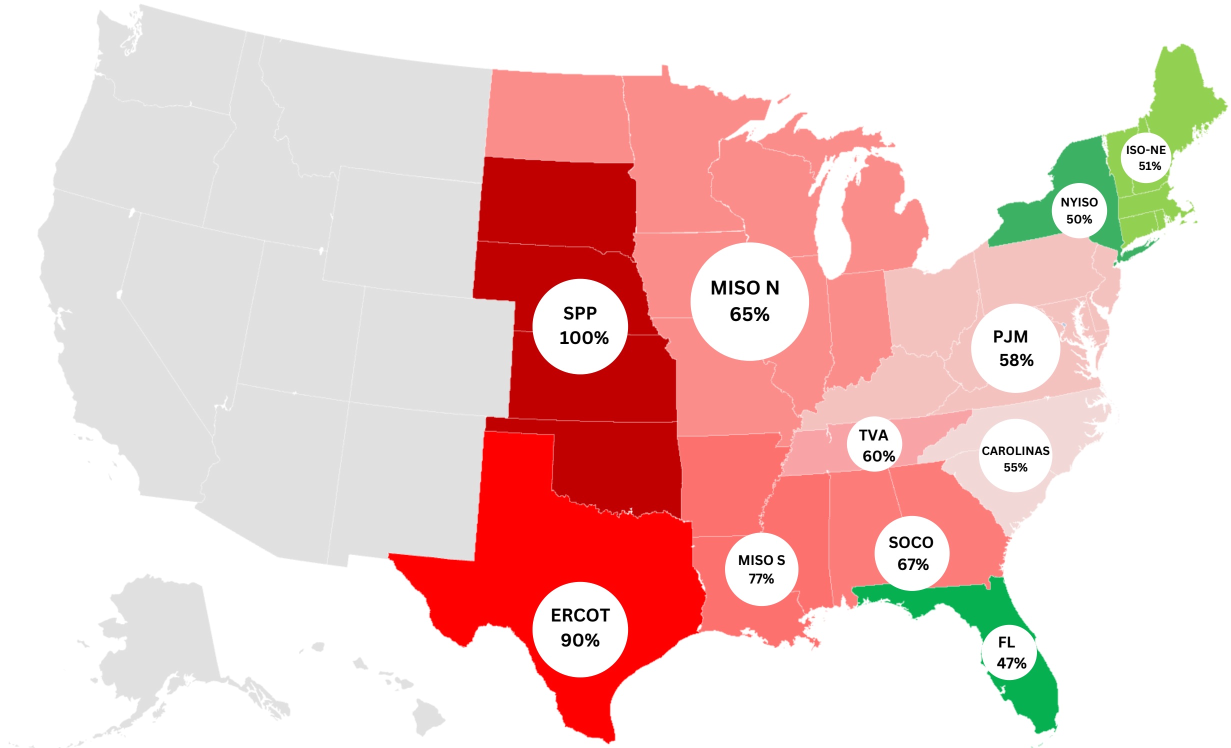
2018 SOUTH CENTRAL COLD WEATHER EVENT, JANUARY 17, 2018, AT 10 AM ET



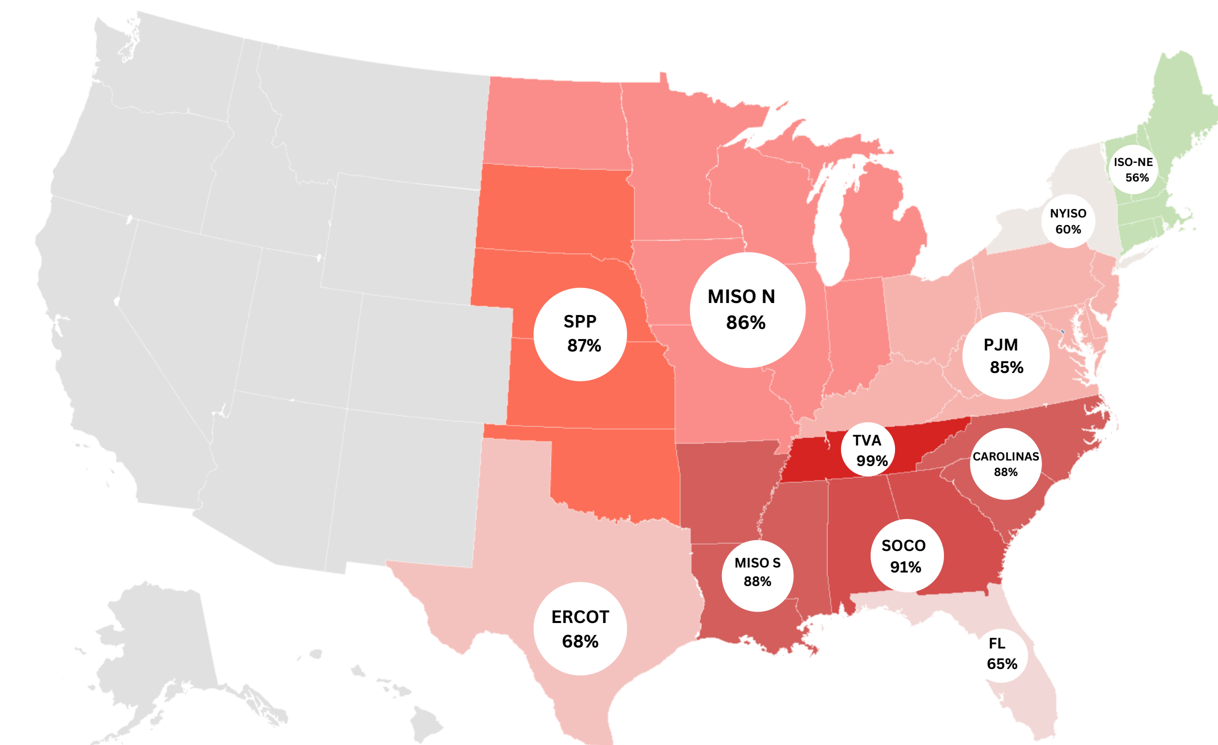
2018 SOUTH CENTRAL COLD WEATHER EVENT, JANUARY 18, 2018, AT 6 AM ET



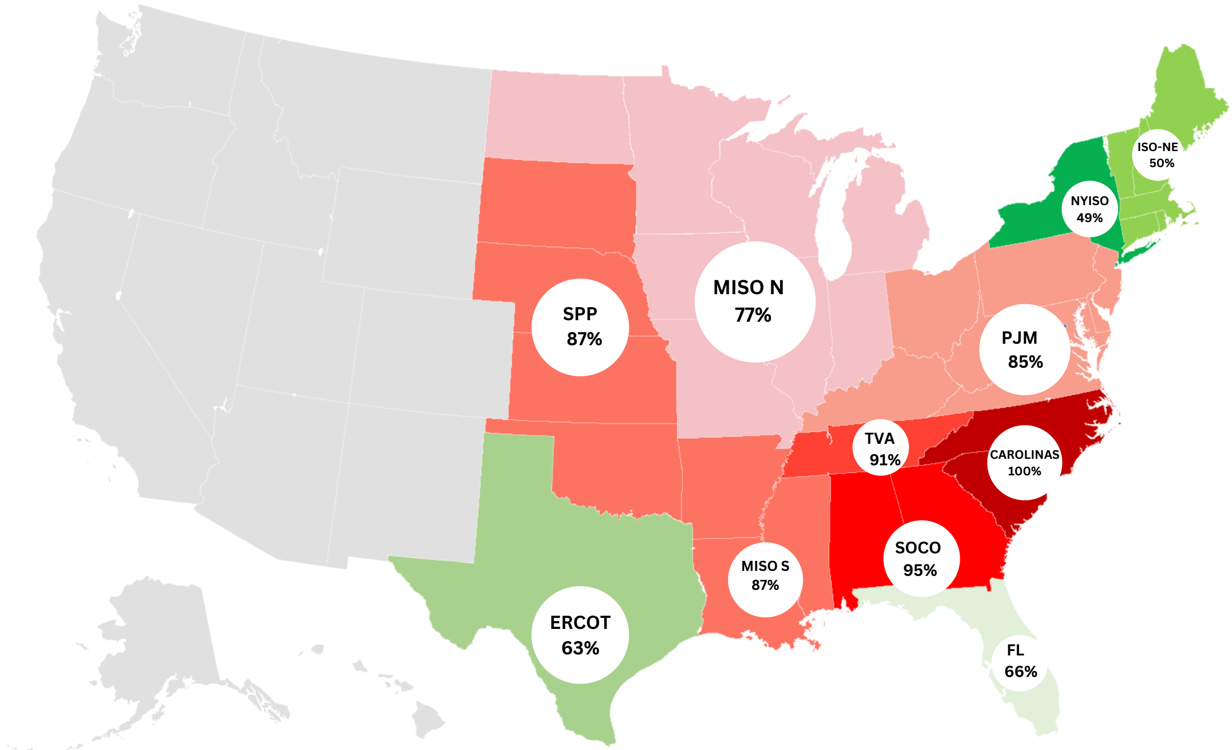
2021 WINTER STORM URI, FEBRUARY 15, 2018, AT 10 AM ET



2022 WINTER STORM ELLIOTT, DECEMBER 23, 2022, 6 PM ET



2022 WINTER STORM ELLIOTT, DECEMBER 24, 2022, 6 AM ET



APPENDIX B

DETAILED METHODOLOGY FOR ANALYSIS OF EASTERN U.S. AND ERCOT

The analysis of geographic diversity across the U.S. portions of the Eastern Interconnection plus ERCOT was conducted for the periods 2012-2015 and 2018-2022. As noted above, the time period 2012-2015 was chosen because data tracking hourly conventional generator forced outages by NERC regional entity are available for that time period from Murphy et al.[14] 2018-2022 was chosen because that time period captures three severe weather events (the 2018 South Central event and Winter Storms Uri and Elliott) for which FERC-NERC reports or other public data sources tracking hourly generator forced outages are available, and because EIA Form 860 began to track Balancing Authorities (BAs') hourly generation by fuel type in July 2018.

The basic methodology was to compare the difference between the aggregated capacity need across the Eastern Interconnect and ERCOT, which accounts for how geographic diversity in hourly electricity demand and supply patterns decreases the need for capacity, against the larger sum of the component regions' stand-alone capacity needs. To calculate capacity needs, hourly renewable output was subtracted from demand and hourly forced outages were added to demand, reflecting that those factors decrease or increase the amount of generation that must be supplied by other resources on a 1:1 basis, equivalent to an identical change in demand.[15] The difference between the maximum aggregated capacity need across the Eastern Interconnect and ERCOT over the nine years versus the sum of the component regions' maximum stand-alone capacity needs over the nine years was then calculated (a difference of 137,146 MW) and reported as a percentage of the sum of the regions' stand-alone peak demands (20.99%).

2012-2015 Hourly Net Load Analysis

For 2012-2015 we collected hourly load and wind generation data from ERCOT,[16] ISO-NE,17 NYISO,[18] PJM,[19] and SPP.[20] We then multiplied the GADS hourly forced outage rate (the sum of hourly derates, start failures, and forced outages) by the installed conventional generator

14 https://www.sciencedirect.com/science/article/pii/S0306261917318202; Supplementary data file available at https://ars.els-cdn.com/content/image/1-s2.0-S0306261917318202-mmc1.zip

15 In this appendix, "net load" is used to refer to hourly load minus wind and solar output plus conventional generator forced outages. "Outages" or "forced outages" is used to refer to conventional generator forced outages, and includes conventional generator failures to start, derates, and forced outages.

16 Hourly Load: https://www.ercot.com/gridinfo/load/load_hist. Hourly Wind: https://www.ercot.com/gridinfo/generation

17 Hourly Load: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info. Hourly Wind: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type

18 Hourly Load: https://www.nyiso.com/custom-reports. Hourly Wind: Did not use wind generation for 2012-2015.

19 Hourly Load: https://dataminer2.pjm.com/feed/inst_load. Hourly Wind: https://dataminer2.pjm.com/feed/wind_gen/definition

20 Hourly Load: https://marketplace.spp.org/pages/hourly-load. Hourly Wind: https://marketplace.spp.org/pages/generation-mix-historical

capacity (Table 1 from Murphy et al.)[21] for each region. Because the GADS outage rate and installed capacity data in Murphy et al. is reported at the NERC region level, which groups ISO-NE and NYISO into NPCC along with the eastern Canadian provinces, we used the installed capacity for NYISO[22] and ISO-NE[23] as reported by those regions' Independent Market Monitors (IMMs) for 2012-2015, but assumed that the NPCC GADS hourly outage rate applied for both regions.

For the entire analysis we separated MISO N and MISO S to account for the limited transmission ties between those areas, and the fact that Entergy was its own BA prior to joining MISO on December 19, 2013. For MISO N a similar issue arose as with NYISO and ISO-NE due to the misalignment of MRO and MISO. To account for this misalignment, we pulled hourly load and wind generation for the entire MISO region for 2012-2015[24] and used IMM reported installed capacity for MISO for 2012-2015.[25] To account for the addition of MISO S at the end of 2013 we subtracted hourly load and MISO S installed capacity from our MISO N hourly load and installed capacity. MISO S is discussed further below. For MISO N, we assumed that the MRO GADS hourly outage rate would apply uniformly across MISO N and multiplied the MRO GADS Hourly Outage by MISO N installed capacity.

To collect Entergy hourly load data before it joined MISO and its load was included in MISO zonal data, we used FERC Form Number 714 data to pull Entergy hourly load for 2012 through December 18, 2013.[26] We then added MISO S reported load for December 19, 2013, through the end of 2015 using MISO's reported load data. For MISO S installed capacity, we used 2012-2015 EIA 860 nameplate capacity (MW) data for Entergy.[27] We then applied Murphy's SERC hourly forced outage rate to Entergy's (MISO S) installed capacity for 2012-2015 to get hourly outages in MISO. No renewable generation was included as MISO S and Entergy had limited installed renewable capacity during this period.

For the non-RTO parts of the Eastern Interconnection we divided it up into four regions: the Southeast,[28] TVA, the Carolinas,[29] and Florida.[30] We again pulled hourly load data from FERC Form Number 714 for the Balancing Authorities that make up each of those regions.[31]

21 Murphy's installed capacity in Table 1 did not include wind or solar capacity. Throughout this appendix we use the term "installed capacity" to refer to conventional generator capacity which does not include wind or solar generating capacity.

22 2012-2015 installed wind capacity, page 66, https://www.nyiso.com/documents/20142/2226467/2015-Load-Capacity-Data-Report-Gold-Book.pdf/63d6d932-7a50-4972-1cc9-e3f1eaa7ab90; 2012-2012 installed capacity, page 339, https://www.potomaceconomics.com/wp-content/uploads/2017/02/NYISO-2015-SOM-Report.pdf

23 For ISO-NE's installed capacity we used FCM results, see page 80, https://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2012/amr12_final_051513.pdf

24 Hourly Load: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/market-report-archives/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AArchived%20Historical%20Regional%20Forecast%20and%20Actual%20Load%20%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc. Hourly Wind: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market- reports/market-reportarchives/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AArchived%20Historical%20Hourly%20Wind%20Data%20%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc

25 2012 installed capacity, page 11, https://www.potomaceconomics.com/wp-content/uploads/2017/02/2012-State-of-the-Market-Report.pdf; 2013 installed capacity, page 23, https://www.potomaceconomics.com/wp-content/uploads/2017/02/2014-State-of-the-Market-Report.pdf; 2014-2015 installed capacity, page 26, https://www.potomaceconomics.com/wp-content/uploads/2017/02/2015-State-of-the-Market-Report.pdf

26 https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data

27 https://www.eia.gov/electricity/data/eia860/

28 The Southeast region is composed of all Southern Company Power Companies (including Gulf Power Co) Balancing Authorities (BAs).

29 The Carolinas region is comprised of the following BAs in North and South Carolina: Duke, Dominion, South Carolina Public Service Authority, and Yadkin.

30 Florida is composed of the following BAs: City of Tallahassee, Florida Municipal Power Agency, Florida Power & Light, Gainesville Regional Utilities, Gulf Power Co (2018-2022 only), JEA, Lakeland Electric, Orlando Utilities Commission, Duke Energy Florida, Seminole Electric Cooperative, and Tampa Electric.

31 The BAs that comprise each region are based on the footnotes above and EIA 930 designations, per https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

For Florida we used Murphy et al.'s installed capacity MW for 2012-2015.[32] For the Carolinas, Southeast, and TVA's installed capacity we used Nameplate Capacity MW from EIA 860 for each Balancing Authority for 2012-2015 and summed it to get a total installed capacity for each region. We then applied Murphy's SERC GADS hourly all outage rate to the Southeast, TVA, and the Carolinas and multiplied it by the installed capacity in each region to Total Hourly MW Outages. No renewable generation was included for any of the three regions as each had limited installed renewable capacity during this period.

All regions were standardized to the Eastern Time Zone and then Total Hourly Outages (MW) were calculated by multiplying Installed Capacity by the NERC region GADS Hourly Outage Percent. We then calculated Total Hourly Net Load by subtracting Hourly Wind Generation from Hourly Load and then adding Total Hourly Outages (MW).

2018-2022 Analysis

For 2018-2022 a similar methodology was used with some changes to the data sources to analyze the Eastern Interconnection and ERCOT. 2018-2022 hourly load and 2019-2022 hourly wind and solar generation was compiled using EIA 930 data for ERCOT, ISO-NE, NYISO, PJM, SPP, TVA, and the Southeast, Carolinas, and Florida regions.[33] EIA 930 did not start reporting hourly wind and solar generation until July 1, 2018, so regionally reported hourly wind and solar generation for 2018 was used for ERCOT, ISO-NE, PJM, and SPP using the same sources as the 2012-2015 analysis. For TVA, Southeast, Carolinas, and Florida, the renewable generation for January 1, 2018, through June 30, 2018, was not included due to limited installed capacity. Hourly MISO data which separates load, wind, solar generation into MISO N and MISO S was used instead of EIA 930 data, which does not distinguish between MISO N and S.[34]

For the RTO regions (except MISO), we again used installed capacity for ERCOT,[35] ISO-NE,[36]

32 Table 1 from Murphy et al.

33 https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48

34 2021-2022 Load: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AHistorical%20Daily%20Forecast%20and%20Actual%20Load%20by%20Local%20Resource%20Zone%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc; 2018-2020 Load: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/market-report-archives/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AArchived%20Historical%20Regional%20Forecast%20and%20Actual%20Load%20%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc; 2021-2022 Wind and Solar: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AHistorical%20Generation%20Fuel%20Mix%20(xlsx)&t=10&p=0&s=MarketReportPublished&sd=desc ; 2018-2020 Wind and Solar: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/market-report-archives/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AArchived%20Historical%20Generation%20Fuel%20Mix%20%20%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc

35 2022: Assumed same installed capacity in 2022 as 2021. 2021: Wind, page 35; Solar, page 32; Installed capacity based on estimate from Figure A16, page A-26, https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/ERCOT_annual_reports/2021annualreport.pdf; 2020: Wind page 25; Solar page 23; Installed capacity based on estimate from Figure A-14, page A-20; https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/ERCOT_annual_reports/2020annualreport.pdf; 2019: Solar based on stated additions in 2020 report, page 22; Wind, page 24; Installed capacity based on estimate from Figure A14, page A-18; https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/ERCOT_annual_reports/2019annualreport.pdf.; 2018: Solar based on estimate from page A-18 in 2019 report; Wind page 80; Installed capacity based on estimate from Figure 64, page 77; https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/ERCOT_annual_reports/2018annualreport.pdf.

36 For ISO-NE's installed capacity we used FCM results, see page 205. For 2018-2020 wind and solar we used a MW of installed capacity that also included DR, Coal, Other, and Battery Storage, Figure 6-2, page 195, https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf.

NYISO,[37] PJM,[38] and SPP[39] as reported by the IMM. For ERCOT, ISO-NE, and SPP, 2021 installed capacity was used for 2022.

For MISO N[40] we used IMM reported total installed capacity minus MISO S installed capacity, which we calculated by summing the EIA 860 nameplate installed capacity for all Entergy Utilities for 2018-2022. For MISO N and S, 2021 installed capacity was used for 2022.

For the Carolinas, Southeast, and TVA, installed capacity was calculated using Nameplate Capacity MW from EIA 860 for each Balancing Authority for 2018-2021 which was then summed to get a total installed capacity for each region. 2021 installed capacity was used for 2022 as 2022 EIA 860 data is not yet available. For Florida, we used installed capacity from the Southern Alliance for Clean Energy's SENFO database for Florida BAs for 2018-2021, which were then summed to get a total installed capacity for Florida for 2018-2021. For Florida's installed renewable capacity we summed the installed nameplate renewable capacity from EIA's 860 data for 2018-2021. For the Carolinas, Southeast, TVA, and Florida installed capacity for 2021 was used for 2022.

For 2018-2022, we did not have access to NERC GADS Hourly Outage data, but we did have hourly outage data for some regions for three extreme weather events during that time period: 2022 Winter Storm Elliott, 2021 Winter Storm Uri, and the 2018 South Central Cold Weather Event. For each of these events there was often post-event reports that tracked outage MWs in the affected regions. We compiled this data to track hourly MW of forced outages at the regional level during those events.

For the 2018 South Central Cold Weather Event, the best outage data came from the FERC-NERC report.[41] Figure 22 from the report details outages for MISO S, SPP, TVA and SERC for January 17, 2018. We manually extracted the numerical hourly MW outages for each region during the event from the figure. For MISO S and TVA, we assumed outages did not include any renewable outages since both regions had limited installed renewables. For SPP and SERC (our Southeast region) a 5% outage rate was assumed for installed renewables during the event and these outages were subtracted from the FERC-NERC Figure 22 outages. For the rest of the Eastern Interconnection Regions and ERCOT we did not have actual hourly outages and an hourly outage rate of 5% was used, except for ISO-NE and NYISO where a 3% outage rate was assumed, approximating those regions' average forced outage rate over the 2012-2015 period per Murphy et al.

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37 2022 Installed capacity, wind, and solar assumed same as 2021. 2020-2021 Installed capacity, wind, and solar, page 71, https://www.nyiso.com/documents/20142/2226333/2021-Gold-Book-Final-Public.pdf/b08606d7-db88-c04b-b260-ab35c300ed64. 2018-2019 Installed capacity, wind, and solar, page 43, https://www.nyiso.com/documents/20142/2226333/2019-Gold-Book-Final-Public.pdf/a3e8d99f-7164-2b24-e81d-b2c245f67904?t=1556215322968.

38 2022 Installed capacity, wind and solar, page 313, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-vol2.pdf. 2021 Installed capacity, wind, and solar, page 295, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol2.pdf. 2020 Installed capacity, wind, and solar, page 272, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol2.pdf. 2019 Installed capacity, wind, and solar, page 262, pg 262; https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-volume2.pdf. 2018 Installed capacity, wind, and solar, page 262, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf

39 2019-2021 installed capacity, wind, and solar, page 52, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf. 2018 installed capacity, wind and solar, page 30, https://www.spp.org/documents/65161/2020%20annual%20state%20of%20the%20market%20report.pdf

40 2020-2021 installed capacity, wind, and solar, page 6, https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf. 2018-2019 installed capacity, wind, and solar, page 6, https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-MISO-SOM_Report_Final_6-16-20r1.pdf

41 Pg 46, https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

For 2021 Winter Storm Uri, the best data also came from the FERC-NERC report for that event.[42] Figure 66b from the report details outages for ERCOT, MISO, and SPP for February 8-20, 2021. From the figure, we manually extracted the numerical MW outages for approximately each 12-hour interval for each region during the event, and then the hourly outages within each 12-hour period were interpolated linearly. However, the report does not include renewable outage rates during the event. For MISO S a 5% outage rate was assumed for installed renewables during the event and these outages were subtracted from the interpolated FERC Figure 66b hourly outages for February 13-20, 2021. For ERCOT, EIA 930 Forecasted Load was used for February 14, 2021 through February 20, 2021, as this better reflected what load would have been without the large loss of load during that period.

Generator outage data for ERCOT and SPP were compiled from those RTOs' outage reports. Both RTOs' reports provide forward-looking projections of outages, which tend to have decreasing accuracy over time. As a result, only the initial hours from each report were used and a linear interpolation was used to fill in the gaps between reports. To account for renewable outages during February 13-20, 2021, 10 real-time ERCOT outage reports from February 13-17, 2021 were used to interpolate renewable outages. The first 6 hours from each report was used and a linear interpolation was used to fill in the gaps between reports. From February 17 at 14:00 through the end of the day February 20th a thermal outage rate was extrapolated using the ratio of the previous total hourly outage compared to thermal outages. For SPP, wind outages were pulled from the first hour of SPP forecasted generator outage reports for February 13, 2021.[43] The first hour of renewable outages from the report was linearly interpolated to February 14th. For February 14th through February 20th, reported wind outages were used from Figure 23 of an SPP report.[44] From the figure we manually extracted the numerical MW outages roughly every 12 hours for SPP wind outages and then the hourly outages in between were interpolated linearly. For the rest of the Eastern Interconnection, we did not have hourly forced outage data, so as above, an hourly forced outage rate of 5% was used, except for ISO-NE and NYISO where a 3% forced outage rate was assumed.

For Winter Storm Elliott, conventional generator correlated outage data was pieced together from preliminary event reports from different regions. For SPP, slide 22 of an SPP Staff Presentation[45] shows outages by generator type for December 19th through December 26th. From the slide we manually extracted the numerical MW outages for roughly every 12 hours during the event, and then the hourly outages in between were interpolated linearly for each 12-hour period. We only used Gas and Coal outages from the chart as outages from other fuel types were negligible and the impact of renewable forced outages is captured in the EIA 930 hourly renewable output data. For PJM, we used Slide 2 from a PJM Winter Storm Elliott Presentation,[46] which shows outages by generator fuel type for December 23rd through December 25th on a two-hour basis. From the slide we manually extracted the numerical MW outages for two-hour blocks during the event. MISO reported system-wide daily average

42 Pg 126, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

43 https://marketplace.spp.org/pages/capacity-of-generation-on-outage

44 Pg 48, https://spp.org/documents/65037/comprehensive%20review%20of%20spp%27s%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf

45 SPP, "DECEMBER 2022 WINTER STORM ELLIOTT," Staff Presentation by C.J. Brown, January 17, 2023, slide 22.

46 Slide 2, https://www.pjm.com/-/media/committees-groups/committees/oc/2023/20230413/20230413-item-04---winter-storm-elliott-fuel-supply-issues.ashx

unplanned generation outages by fuel type for December 22nd through December 24th.[47] The reported daily averages were entered for Hour 12 of December 22, 23, and 24, and then a linear interpolation was done between those hours. The outages were then split proportionally between MISO N and MISO S based on installed capacity. For TVA and the Carolinas, outages were determined by taking the difference between the EIA 860 installed thermal capacity for the region in 2022 and comparing it to the lowest hour of thermal generation (coal, gas, and nuclear) during each region's rolling blackout period(s) during Winter Storm Elliott, based on the assumption that all thermal generation would have been fully dispatched during this period.[48] We did not have hourly outage data for the rest of the Eastern Interconnection and ERCOT, so as above an hourly outage rate of 5% was used, except for ISO-NE and NYISO where a 3% outage rate was assumed.

All hourly data for demand, renewable output, and forced outages were converted to the Eastern Time Zone. Total Hourly Outages (MW) were then calculated outside of the three extreme weather events by multiplying by the assumed 5% or 3% outage rate discussed above. We then calculated Total Hourly Net Load for 2018-2022 by subtracting Hourly Wind and Solar Generation from Hourly Load and then adding Total Hourly Outages (MW).

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47 Slide 10, https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf

48 Reported rolling blackouts for both TVA and Duke during Winter Storm Elliot from this article: https://rmi.org/wasted-wind-and-tenable-transmission-during-winter-storm-elliott/