UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Technical Conference Docket No. AD21-11-000

COMMENTS OF AMERICANS FOR A CLEAN ENERGY GRID

Pursuant to the Commission's Notice Inviting Post-Technical Conference Comments issued on January 7, 2022, Americans for a Clean Energy Grid (ACEG)[1] submits these Comments in support of the development of interregional capacity requirements to maintain electric system reliability during extreme weather and everyday risks and challenges.

I. INTRODUCTION AND SUMMARY

Severe weather events have challenged nearly every part of the U.S. power grid in the last decade.[2] They are becoming more common and more extreme. For example, in February 2021, millions of Americans experienced prolonged power outages as electricity demand exceeded supply when record cold weather hit much of the Central U.S. The February power outages contributed to hundreds of deaths in Texas and elsewhere.[3] Severe weather events

[1] ACEG represents a diverse coalition of stakeholders focused on the need to expand, integrate and modernize the high-voltage grid in the United States. The ACEG coalition includes multi-state utilities that develop, own, and operate transmission, trade groups that include transmission owners and transmission equipment manufacturers among their members, renewable energy trade groups and advocates, environmental advocacy organizations, buyers of energy, and energy policy experts. ACEG seeks to educate the public, opinion leaders, and public officials about the needs and potential of the transmission grid. These comments do not necessarily reflect the views of individual members.

[2] Grid Strategies LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2021) (***Attachment 2***) (citing NOAA National Centers for Environmental Information, *Billion-Dollar Weather and Climate Disasters: Overview* (2021) *available at* https://www.ncdc.noaa.gov/billions/events/US/2021).

[3] Grid Strategies LLC, *The One-Year Anniversary of Winter Storm Uri, Lessons Learned and the Continued Need for Large-Scale Transmission* at 2 (February 13, 2022) (***Attachment 3***). *See also* ***Attachment 2*** at 1 (citing Peter Aldhous, Stephanie M. Lee, and Zahra Hirji, *The Texas Winter Storm*

are estimated to cost Americans between $25-70 billion each year.[4]

Strengthening the transmission grid and increasing interregional ties are essential for preventing future outages. Stronger transmission ties to neighboring regions can be a lifeline to prevent power outages by cancelling out local fluctuations in the weather that affect electricity demand. This is primarily due to fluctuations in heating/cooling needs and electricity supply, including changes in wind and solar output as well as failures of conventional power plants due to extreme weather. Many severe weather events migrate from region to region, allowing one region to import electricity during its time of need and then export to other regions once the storm moves on. Grid operators have confirmed that connecting large geographic areas via transmission saves consumers billions of dollars per year, during severe weather and otherwise, by reducing the need for power plant capacity by reducing variability in electricity supply and demand.[5] An integrated transmission grid network also provides valuable resilience, so if some power lines or power plants are taken offline by any type of disaster, there are alternative sources of power available.

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and Power Outages Killed Hundreds More People Than the State Says (May 26, 2021) *available at* https://www.buzzfeednews.com/article/peteraldhous/texas-winter-storm-power-outage-death-toll).

[4] ***Attachment 2*** at 1, 12 (citing Executive Office of the President, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages* (August 2013) *available at* https://www.energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf).

[5] ***Attachment 2*** at 1 (citing PJM, *PJM Value Proposition* (2019) *available at* https://www.pjm.com/%20about-pjm/~/media/about-pjm/pjm-value-proposition.ashx; MISO, *Value Proposition* (2020) *available at* https://cdn.misoenergy.org/2020%20MISO%20Value%20Proposition%20Flyer%20One%20Pager521883.pdf).

In the January 7, 2022 Notice, the Commission asked for comments on issues related to the reliability of the Bulk Power System, including what changes could be made to the NERC Reliability Standards to increase resilience:

> Should transmission planning Reliability Standards be revised to require the system to meet more stringent planning criteria for extreme weather conditions? Should the TPL Reliability Standards be revised so that certain amounts of transmission capacity between regions are maintained for use during extreme weather events?[6]

The answer to both of these questions is yes. The benefits of interregional coordination, including capacity sharing in times of need, are widely accepted. The essential role of large-scale transmission for reliability was emphasized by multiple panelists at the technical conference. Jim Robb, NERC President and CEO, pointed out that "transmission infrastructure will be required to support reliability as the grid continues to transform. This includes infrastructure to support resilience, and to deliver renewable resources from remote areas to load centers."[7] Former FERC Commissioner Cheryl LaFleur stated that transmission "helps keep the lights on"[8] and Debra Lew of the Energy Systems Integration Group recommended that it is "in our best interest as a country to take advantage of our huge geographic diversity to smooth the variability with increased large scale transmission that connects this diversity."[9] Mark Ahlstrom from NextEra expressed support for a national macro grid, stating that it is "the best answer to resilience you can find" and "has all kinds of economic benefits as well."[10]

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[6] January 7, 2022 Notice at 4 (Section 2.d.i).

[7] Reliability Technical Conference, Tr. at 19:20-24, Docket No. AD21-11-000 (Sept. 30, 2021).

[8] *Id.* at 90:10-12.

[9] *Id.* at 263:17-21.

[10] *Id.* at 280:17-23.

At the February 16, 2022 Joint Federal-State Task Force on Electric Transmission meeting, Commissioner Christie raised the issue of whether there should be a mandatory interregional capacity requirement. ACEG agrees that an interregional capacity requirement would be a useful tool to maintain reliability among regional electric systems. As discussed below and in the attached reports, there is extensive evidence that interregional capacity transfers can prevent power outages during severe weather events, support normal grid operations at lower cost and provide invaluable resilience benefits in all parts of the U.S. The Commission should establish a minimum interregional capacity requirement to ensure that these benefits are available when needed. The Commission could also be effective in establishing planning rules that enhance transmission coordination and operations across regional seams. If the Commission does not establish a required amount of interregional capacity, it should at least require planning regions to start using a uniform modeling approach with common assumptions, methods and timelines.

II. ATTACHMENTS

ACEG's Comments discuss the findings and conclusions reached in the attached reports that analyze the value of interregional capacity availability:

Attachment 1	*Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights On When There is a Loss of Generation*, by Grid Strategies LLC (November 2021)
Attachment 2	*Transmission Makes the Power System Resilient to Extreme Weather*, by Grid Strategies LLC (July 2021)
Attachment 3	*The One-Year Anniversary of Winter Storm Uri, Lessons Learned and the Continued Need for Large-Scale Transmission*, by Grid Strategies, LLC (February 13, 2022)
Attachment 4	*Potential Customer Benefits of Interregional Transmission*, General Electric International, Inc. (Nov. 29, 2021)
Attachment 5	*A Roadmap to Improved Interregional Transmission Planning*, Brattle Group (Nov. 30, 2021)

III. COMMENTS

A. Interregional Capacity Requirements Can Save Billions of Dollars by Providing Added Energy Security During Extreme Weather Events.

The attached 2021 report, *Transmission Makes the Power System Resilient to Extreme Weather*, analyzes five recent severe weather events that have occurred across the U.S. in just the past decade. It determines the dollar value that additional transmission ties would have provided:[11]

- Winter Storm Uri (February 2021) – An additional 1 gigawatt (GW) of transmission ties between ERCOT and the Southeastern U.S. could have saved nearly $1 billion and kept power flowing to hundreds of thousands of Texans. Each 1 GW of transmission ties could have saved an additional $100 million to consumers in the Great Plains (SPP region) and Gulf Coast States (MISO region).

- Texas Heatwave (2019) – An additional 1 GW of transmission ties between ERCOT and the Southeastern U.S. could have saved consumers $75 million in higher power prices.

- Polar Vortex (2019) – An additional 1 GW of transmission could have saved Midwest consumers $2.4 million, but this event was more notable for showing how transmission expansion benefits both interconnected regions. Higher wind production in PJM was able to move westward to support the MISO grid during its time of peak demand, a reversal of the typical eastward flow of power.[12]

- North East Bomb Cyclone (December 2017-January 2018) – New England, New York and Mid-Atlantic regions could have *each* saved $30-40 million for each GW of stronger transmission ties. Stronger transmission ties between the Mid-Atlantic region and Chicago could have provided an additional $40 million in benefits during this same event.

- North East Polar Vortex (January 2014) – New England, New York and Mid-Atlantic regions could have each saved between $9 to $21 million with stronger transmission ties.

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[11] Grid Strategies LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2021) (***Attachment 2***).

[12] *Id.* at 17.

It is estimated that transmission lines cost approximately $700 million per GW of transfer capacity.[13] In the case of the February 2021 Texas outages, the value of power delivered to Texas could have fully covered the cost of new transmission to the Southeast.[14] For other lines and severe weather events the value of added transmission ties for just one event could have defrayed a significant portion of the cost of building transmission.

B. Interregional Capacity Requirements Can Make the Transmission Grid Stronger Every Day.

A stronger transmission grid with robust interregional ties will be valuable every day, not just during extreme weather events.[15] For example, transmission ties that are valuable during severe weather events can also deliver the Midwest's low-cost wind resources to electricity demand centers in the Eastern U.S. Power can flow in both directions on transmission, so consumers at both ends of the transmission line benefit. Most of the time these transmission lines will export wind generation from the Midwest, but during an emergency power can flow to the Midwest. Recent studies show that interregional transmission ties become increasingly valuable as wind and solar generation increases in different parts of the country.[16] Just as these transmission lines aggregate diverse sources of

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[13] This estimate is based on the average cost for 18 above-ground, shovel-ready projects identified in a recent report, though costs vary considerably based on the length of the line and other factors. See ***Attachment 2*** at 3-4 (citing Michael Goggin, Rob Gramlich, and Michael Skelly, *Transmission Projects Ready to Go: Plugging Into America's Untapped Renewable Resources* (April 2021) *available at* https://cleanenergygrid.org/wp-content/uploads/2019/04/Transmission-Projects-Ready-to-Go-Final.pdf).

[14] Brattle Group, *A Roadmap to Improved Interregional Transmission Planning* at 1 (Nov. 30, 2021) (***Attachment 5***) at 1.

[15] ***Attachment 3*** at 1.

[16] ***Attachment 2*** at 6. *See also* General Electric International, Inc., *Potential Customer Benefits of Interregional Transmission* at 8 (Nov. 29, 2021) (***Attachment 4***) (identifying three areas of reliability opportunity as the nation shifts to variable renewables: adequacy, operations and stability).

electricity supply and demand to balance out localized disruptions during extreme weather, they provide a similar value by canceling out local fluctuations in wind or solar output.

The Nation's power grid has approximately 600,000 circuit miles of transmission lines, with about 240,000 miles of intra and interregional high-voltage transmission lines.[17] Events that interrupt generation tend to be more localized, allowing for regions to call upon these interregional transmission lines to import electricity from regions experiencing different weather patterns to cancel out local fluctuations in electricity supply and demand. A region can also take advantage of ties between regions to export electricity to avoid renewable generation curtailments as well as manage internal congestion and transmission flows. Interregional transmission ties are the "lifelines" that keep the grid up and running when these types of interruptions occur.[18]

Today's regional planning analyses consider an overly narrow set of benefits, with many benefits either not considered or not quantified.[19] As a result, despite the positive role interregional transmission plays in supporting grid resiliency, annual regionally planned transmission investment in RTOs and ISOs has decreased steadily over the last decade.[20] There have been no major interregional transmission projects built in the U.S. during that time.[21] This trend must be reversed.

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[17] Grid Strategies LLC, *Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights On When There is a Loss of Generation* at 1 (November 2021) (***Attachment 1***).

[18] ***Attachment 4*** at 20 (concluding that coordinated interregional transmission is a proven enabler for resilient decarbonization.).

[19] ***Attachment 5*** at vi, 4, 20-25.

[20] *Id.* (citing Gramlich and Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 25 (January 2021)).

[21] ***Attachment 5*** at iii, 3.

C. The Commission Should Establish Minimum Interregional Capacity Requirements to Ensure that Reliability Benefits Will Be Available in the Future.

Despite the large savings of interregional capacity availability discussed above, transmission planning and cost allocation analyses typically do not account for transmission's value for making the grid more resilient against severe weather and other unexpected threats. Transmission planning processes usually assume normal electricity supply and demand patterns, and do not account for the value of transmission for increasing resilience or the hedging or insurance value from protecting consumers against the economic and reliability impacts of severe weather events.

There is a growing consensus in the industry that the benefits of a minimum interregional capacity requirement exceed the costs. Some form of a minimum interregional capacity requirement is supported by dozens of commenters in the Commission's Transmission Planning ANOPR in Docket No. RM21-17.[22] The benefits include delivering renewable resources to load, along with increased reliability, resiliency, market efficiency, and resource adequacy.[23] In fact, as noted above, there are substantial costs and risks to not expanding interregional transmission planning.

The Commission should establish pro-transmission policies that account for the many benefits of interregional transmission. "Just as President Eisenhower created the interstate highway system to protect national security and facilitate interregional trade, there is a clear national interest in ensuring that the backbone of the 21st century economy — the power grid

[22] ***Attachment 5*** at iii, 3. Approximately 32 commenters favored improving interregional planning processes, including LS Power, PJM, Kansas Corp. Commission, Arizona Corp. Commission, Mass. Dept. Energy Resources, New Jersey BPU, and AEP.

[23] ***Attachment 5*** at iii.

— is strong and secure."[24] Among other things, the Commission should require greater regional and interregional coordination in how transmission is planned and funded. The Commission should require minimum levels of interregional transmission to maximize grid reliability and to ensure that these benefits are available when needed. The Commission should also establish planning rules that enhance transmission coordination and operations across regional seams on a planning basis. Even if the Commission does not establish a required amount of interregional capacity, it should at least require planning regions to use a uniform modeling approach that incorporates common assumptions, methods and timelines.

IV. CONCLUSION

As discussed above, ACEG supports the development of interregional capacity requirements to maintain electric system reliability during extreme weather and everyday other risks and challenges. ACEG respectfully requests that the Commission establish minimum interregional capacity requirements to ensure that reliability benefits will be available in the future.

Respectfully submitted,

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Date: February 22, 2022

[24] ***Attachment 2*** at 5.

Attachment 1

Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights On When There is a Loss of Generation
by Grid Strategies LLC (November 2021)

Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights on When There Is a Loss of Generation[1]

Michael Goggin
Rob Gramlich
Jay Caspary
Jesse Schneider

November, 2021

I. Overview

Resilience of the US power grid is a foundational building block for the safe, reliable, and secure delivery of electricity across the country. Our grid, however, is subject to an increasing variety and magnitude of threats, both natural and man-made, which can serve to interrupt generation resources and much needed service to load centers. What's more, researchers have found that correlated, unplanned generator outages are present in most NERC regions and represent a significant resource adequacy risk.[2] All generation resource types can be affected by unplanned outages, whether the events are caused by an extreme weather event or even a targeted attack on the grid.

The US power grid boasts over 600,000 circuit miles of transmission lines, approximately 240,000 of which are intra and interregional high-voltage transmission lines.[3] Events that interrupt generation tend to be more localized, allowing for regions to call upon these interregional transmission lines to import electricity from regions experiencing different weather patterns to cancel out local fluctuations in electricity supply and demand. A region can also take advantage of ties between regions to export electricity to avoid renewable curtailments as well as manage internal congestion and transmission flows. In a sense, interregional transmission ties are the "lifelines" that keep the grid up and running when these types of interruptions occur. Despite the role interregional transmission plays in supporting grid resiliency, annual regionally planned transmission investment in RTOs/ISOs has decreased steadily over the last decade.[4]

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[1] This report was not commissioned by any entity but is related to work for various clients interested in clean energy and reliability.
[2] Murphy, Apt, Moura, and Sowell, *Resource Adequacy Risks to the Bulk Power System in North America*, Carnegie Mellon Electricity Industry Center Working Paper, (n.d.); Murphy and Sinnot, *Correlated Generator Failures and Power System Reliability*, Carnegie Mellon University, 2019.
[3] Edison Electric Institute, "Transmission," (n.d.)
[4] Gramlich and Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 25, January 2021.

In a Commission-led proceeding on grid resilience, grid operators and experts highlighted the importance of interregional transmission during threats to the system:

- NYISO: "[R]esiliency is closely linked to the importance of maintaining and expanding interregional interconnections, [and] the building out of a robust transmission system."[5]

- ISO-NE: "The system's ability to withstand various transmission facility and generator contingencies and move power around without dependence on local resources under many operating conditions . . . results in a grid that is, as defined by the Commission, resilient."[6]

- PJM: "Robust long-term planning, including developing and incorporating resilience criteria into the [Regional Transmission Expansion Plan], can also help to protect the transmission system from threats to resilience."[7]

- SPP: "The transmission infrastructure requirements that are identified through the [Integrated Transmission Plan (ITP)] process are intended to ensure that low cost generation is available to load, but the requirements also support resilience in that needs are identified beyond shorter term reliability needs. For example, the ITP identified the need for a number of 345 kV transmission lines connecting the panhandle of Texas to Oklahoma. These lines were identified as being economically beneficial for bringing low-cost, renewable energy to market, but their construction has also supported resilience by creating and strengthening alternate paths within SPP."[8]

- Brattle Group analysts: "The power system can be vulnerable to disruptions originating at multiple levels, including events where a significant number of generating units experience unexpected outages. The transmission system provides an effective bulwark against threats to the generation fleet through the diversification of resources and multiple pathways for power to flow to distribution systems and ultimately customers. By providing customers access to generation resources with diverse geography, technology, and fuel sources, the transmission network buffers customers against extreme weather events that affect a specific geographic location or some external phenomenon (unavailability of fuel and physical or cyber-attacks) that affect only a portion of the generating units."[9]

This report documents numerous instances of broad failures of generation, beyond what is considered in typical capacity markets or integrated resource plans (which typically assume all

[5] *Response of the New York Independent System Operator, Inc.*, Docket No. AD18-7, at 4, March 9, 2018
[6] *Response of ISO New England Inc.*, Docket No. AD18-7, at 15, March 9, 2018.
[7] *Comments and Responses of PJM Interconnection, L.L.C.*, Docket No. AD18-7, at 49, March 9, 2018.
[8] *Comments of Southwest Power Pool, Inc. on Grid Resilience Issues*, Docket No. AD18-7, at 8, March 9, 2018
[9] Chupka and Donohoo-Vallett, *Recognizing the Role of Transmission in Electric System Resilience*, at 3, May 9, 2018.

generator outages are independent of one another). When some event affects a broad set of generation in an area, this "common mode failure" is often not incorporated into generation capacity planning, but should be incorporated into interregional transmission planning because as many ISO/RTOs have said, interregional transmission often saves the day by sharing resources from one area with another.

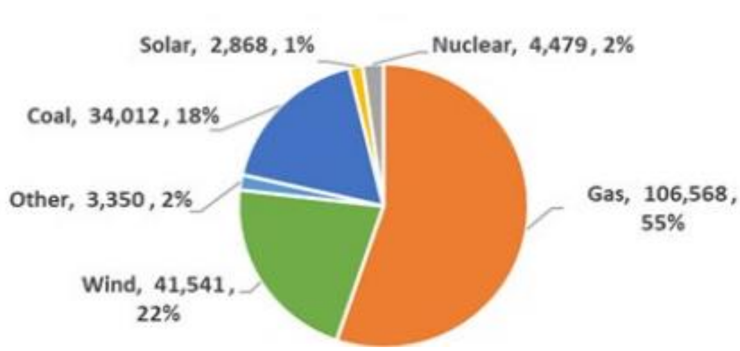
A closer look at a handful of recent ex post extreme weather event analyses from RTOs and ISOs demonstrates how outages can affect a wide range of generation resource types. Data from these analyses and the U.S. Energy Information Administration's "Hourly Electric Grid Monitor"[10] also provide a snapshot of imports and exports to and from affected regions over the event time frames, which tells the compelling story of how interregional transmission helps keep the lights on when local supply is unavailable and demand spikes.

II. Recent Extreme Weather Event Examples

a. Winter Storm Uri (February 2021)

The extreme cold weather event affecting Texas and other parts of the Central US during the week of February 14, 2021 led to the most unplanned cold weather-related generation outages of any cold weather event in the area in the last decade. According to the FERC, NERC and Regional Entity Joint Staff Inquiry, ERCOT experienced capacity outages from generating units of all fuel types averaging 34,000 MW for two consecutive days – nearly half of its 2021 all-time winter peak load of 69,871 MW.[11] Unplanned outages and derates for the entire event area reached 192,818 MW, as shown in Figure 1 below:

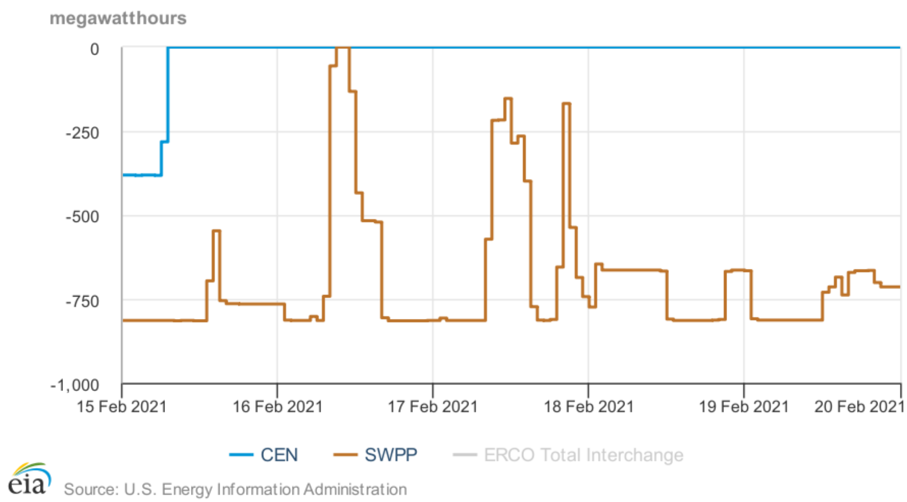
Figure 1: Fuel type of generating units that experienced unplanned outages and derates (by MW of nameplate capacity), total event area[12,13]



[10] U.S. Energy Information Administration, "Hourly Electric Grid Monitor," last accessed November 23, 2021.
[11] FERC, NERC, and Regional Entity Joint Staff, *February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations*, at 5, last updated September 23, 2021.
[12] *Ibid*.
[13] It would be more appropriate to use accredited capacity rather than nameplate capacity.

Due to a lack of interregional ties, ERCOT was only able to import approximately 800 MW of power from SPP during the week of the cold snap, as shown in Figure 2 below.[14] SPP experienced shortfalls itself, as demonstrated by the spikes on the 15th and 16th, which were exacerbated due to the scheduled outages of three of seven western interconnection DC ties – Eddy County, Blackwater, and Rapid City.[15] ERCOT was able to import an additional 400 MW from Mexico up until the 15th, when Mexico experienced natural gas supply shortages.

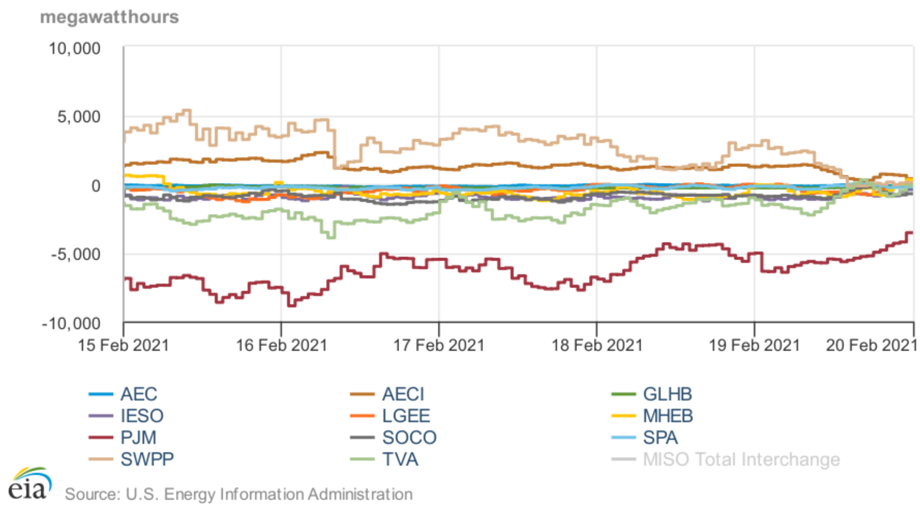
Figure 2: Electric Reliability Council of Texas, Inc. (ERCO) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time



While MISO and SPP also experienced similar cold weather conditions, those RTOs were able to import electricity from other regions experiencing milder temperatures. For example, at maximum, MISO was able to import approximately 9,000 MW from PJM, a few thousand MW from the Tennessee Valley Authority (TVA), and a combined 3,000 MW from Southern Company, Louisville Gas and Electric and Kentucky Utilities Company, and Canada. As a result of its interregional capacity, MISO was able to import a total of 13,000 MW during the peak of the event - about 15 times as much power as ERCOT was able to import. MISO was also able to export 5,000 MW and 2,500 MW to SPP and Associated Electric Cooperative Incorporated, respectively, over the course of the cold snap.[16]

[14] Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, at 8, July 2021.
[15] SPP, *A Comprehensive Review of Southwest Power Pool's response to the February 2021 Winter Storm*, at 68, July 19, 2021.
[16] Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, at 8, July 2021.

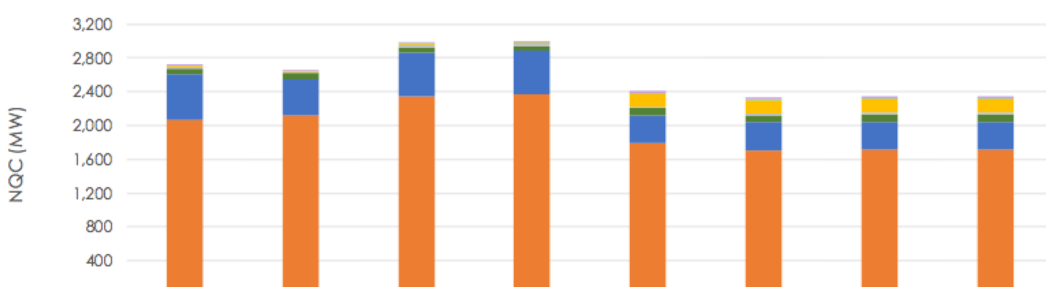
Figure 3: Midcontinent Independent System Operator, Inc. (MISO) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time



b. CAISO Extreme Heat Wave (2020)

On August 14-15, 2020, CAISO experienced a "1-in-30-year" weather event that forced the grid operator to institute rotating electricity outages throughout the state. As shown in figure 4 below, net qualifying capacity (NQC) outages over the two-day event ranged from 2,333 to 2,996 MW and impacted a variety of resources. Most of these outages, however, were natural gas units, as thermal resources were derated or taken offline by the high temperatures.

Figure 4: CAISO resource adequacy outage snapshot during 2020 heat wave (August 14-15)[17]



	8/14, Stage 2 (3:25 pm)	8/14, Peak (4:56 pm)	8/14, Stage 3 (6:38 pm)	8/14, Net demand peak (6:51 pm)	8/15, Peak (5:37 pm)	8/15, Stage 2 (6:16 pm)	8/15, Net demand peak (6:26 pm)	8/15, Stage 3 (6:28 pm)
Other	10	5	7	7	27	26	26	26
Wind	0	0	13	13	6	6	6	6
Solar	6	7	7	7	155	155	155	155
Import	29	19	29	29	20	29	29	29
Geothermal	69	69	60	60	79	79	79	79
Hydro	535	424	508	509	336	335	335	335
Natural gas	2,070	2,123	2,352	2,371	1,788	1,704	1,714	1,714
Grand total	2,719	2,647	2,976	2,996	2,411	2,333	2,344	2,344

[17] CAISO, *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, at 87, January 13, 2021

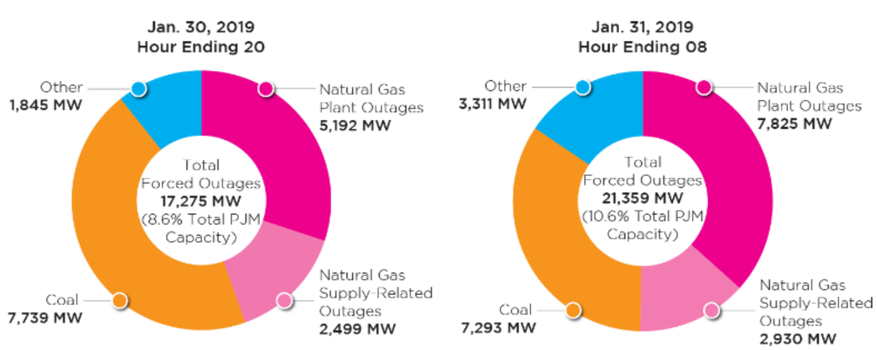
As these outages were taking place, real-time imports needed to meet high loads and counter outages increased by 3,000 and 2,000 MW on the 14th and 15th, respectively.[18] CAISO, however, notes it could have imported even more capacity if it had not had to derate the California Oregon Intertie (COI) prior to the event due to a damaged, upstream transmission line in the Pacific Northwest. CAISO stated, "...more energy was available in the north than could be physically delivered, and the total import level was less than the amount the CAISO typically receives."[19] Just as CAISO acknowledges more interregional transmission would have allowed capacity imports to reduce or eliminate the need for outages, all regions would similarly benefit from increased interregional transmission during extreme weather events.

The ability to move power between the existing interconnections is limited by the relatively small size of Back-to-Back (B2B) HVDC ties which are aging and in most cases approaching their end-of-life. The aggregate nameplate capacity of the B2B HVDC ties between the eastern and western grids in North America is only 1,320 MW and in most cases is limited by the capability of the equipment in the B2B HVDC tie substations and not the capacity of the adjacent AC systems. During the most recent blackouts in California, significant resources, which were primarily wind, were available in SPP but were not deliverable into the western grid due to the lack of capacity on the critical interface between the eastern and western interconnections.

c. Polar Vortex (January 2019)

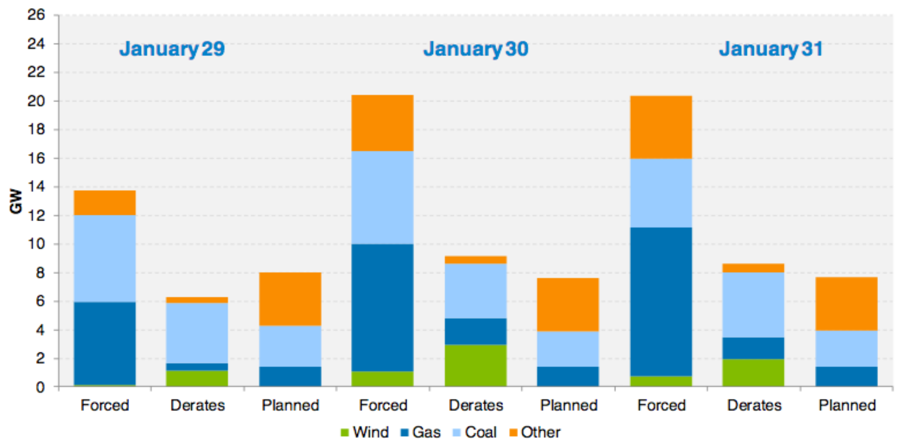
A polar vortex affecting PJM and MISO during the week of January 28, 2019 caused both RTOs to experience higher than normal levels of unplanned outages. Ex post analyses show generating units of all fuel types were impacted by forced outages. Between January 30th and 31st, PJM and MSO experienced forced outages averaging 19,317 MW and 20,500 MW, respectively. Figure 5 below depicts forced outages by fuel type in PJM from January 30th through 31st, and Figure 6 shows the total of forced outages, planned outages and derates in MISO from January 29th through 31st:

Figure 5: Forced outages in PJM during the 2019 polar vortex (January 30-31)[20]



[18] *Ibid*., at 49.
[19] *Ibid*., at 48.
[20] PJM, *Cold Weather Operations Summary January 28-31, 2019*, at 4, 2019.

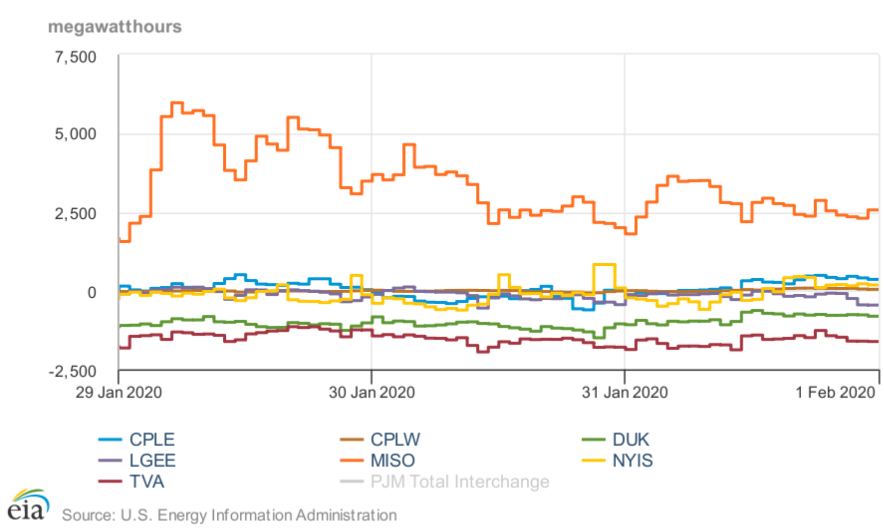
Figure 6: Generation outages and derates in MISO north/central during the 2019 polar vortex (January 29-31)[21]



During the extreme cold weather event, PJM was able to import a combined 3,500 MW from TVA, Duke Energy Carolinas, Duke Energy Progress East and West, Louisville Gas and Electric and Kentucky Utilities Company, and NYISO. At the same time, PJM was able to export over 5,000 MW to MISO on the 29th, at least partially due to higher than average wind output.

A look at MISO's import and exports during the polar vortex tells a similar story. On the 29th, MISO was able to import 7,500 MW from neighboring balancing authorities and RTOs, while exporting around 2,000 MW to TVA over the same time frame. Figures 7 and 8 below show the breakdown of imports and exports to and from PJM and MISO during the Polar Vortex.

Figure 7: PJM Interconnection, LLC (PJM) electricity interchange with neighboring balancing authorities 1/29/2019-1/30/2019, Eastern Time



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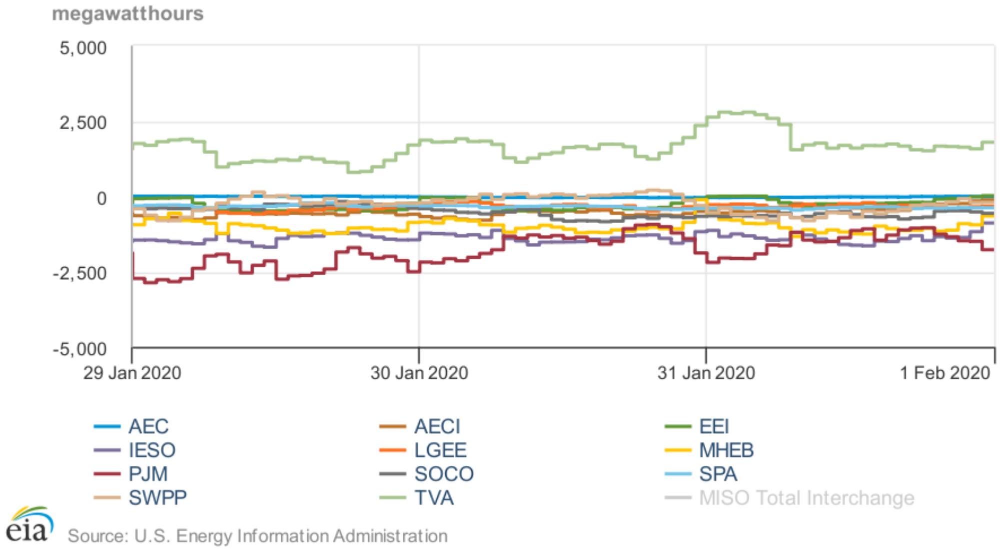
[21] MISO, *MISO 2018-2019 Winter Assessment Report: Market and Operations Analytics*, at 20, April 2019.

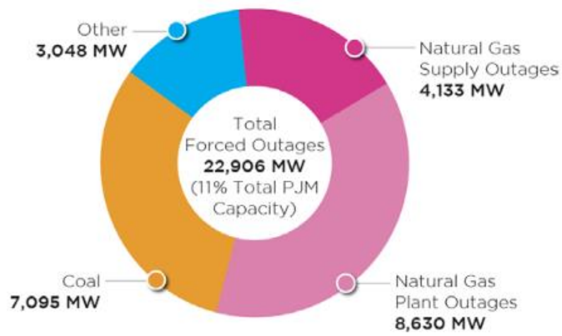
Figure 8: Midcontinent Independent System Operator, Inc. (MISO) electricity interchange with neighboring balancing authorities 1/29/2019-1/30/2019, Eastern Time



d. Bomb Cyclone (2017-2018)

The Northeast experienced a prolonged cold spell as well as a rapid plunge in barometric pressure, known as a "Bomb Cyclone," between December 26th and January 7th, which brought heavy snow and ice to the region. The weather event, which caused the coldest twelve-day stretch in New England since 1980 and three of PJM's top 10 winter peak demand days of all time, spared no resource when it came to unplanned outages. PJM found that total forced outages on the morning of January 6th totaled 22,906 MW, with most outages affecting natural gas and coal units:

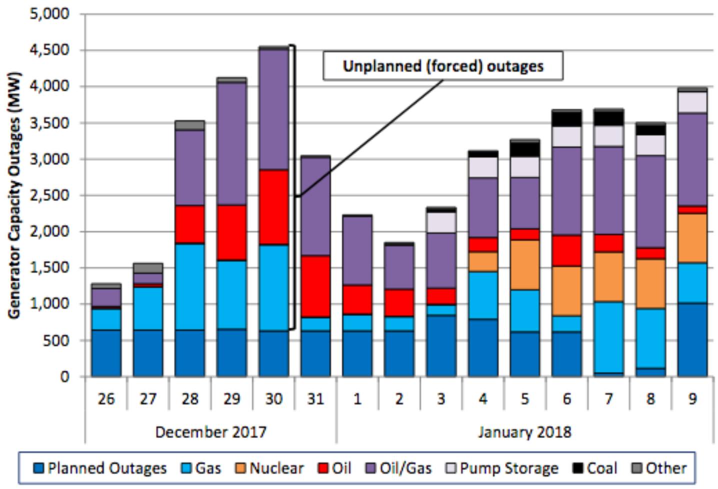
Figure 9: Forced outages in PJM during 2017/2018 bomb cyclone (January 6th)[22]



[22] Ott, *Examining the Performance of the Electric Power Systems Under Certain Weather Conditions*, Testimony of Andrew L. Ott, President & CEO PJM Interconnection, L.L.C. before the United States Senate Committee on Energy and Natural Resources, at 5, January 23, 2018.

Similarly, ISO New England found a variety of resource-types were affected by forced outages over the course of the event:

Figure 10: Average generation out of service in ISO New England by fuel type (December 26-January 9)[23]

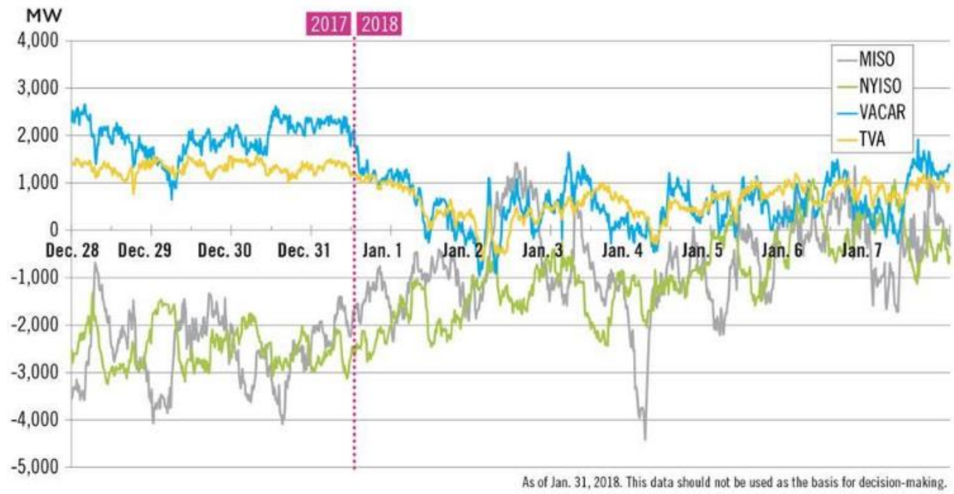


ISO New England notes in their ex post analysis that although outages peaked on December 30 at approximately 4,500 MW, consisting of predominantly oil and gas units, outages increased days later after a nuclear unit was forced out of service due to a weather-related transmission line trip.

When asked about interregional transmission during the US Senate Committee on Energy and Natural Resources hearing on the performance of the of the northeast power grid during bomb cyclone, PJM President and CEO Andrew Ott stated power was able to flow from MISO to PJM for a number of hours during the cold snap. The following graph shared in the testimony also shows NYISO was able to export approximately 2-3 GW to PJM during the first few days of the cold snap:

[23] ISO New England Internal Market Monitor, *Winter 2018 Quarterly Markets Report*, at 35, May 2, 2018.

Figure 11: PJM interchange, Dec. 28 2017 to Jan. 7, 2018[24]



e. Browns Ferry Nuclear Plant Derate Due to Extreme Heat (2010)

Much like coal-fired power plants, nuclear facilities require large quantities of water for cooling operations. Extreme weather can indirectly impact nuclear power plant operations due to cooling water intake disruptions. In 2010, a prolonged spell of hot weather forced the Browns Ferry 3.8 GW nuclear power plant in Alabama to operate at 50% of its maximum output, as surrounding river water was too warm for the plant to draw in to cool the plant's reactors.[25]

Extreme heat can cause intake and discharge water temperatures to reach levels unsuitable for cooling operations (and water quality standards in the case of discharge water), and drought conditions brought on by extreme heat can lead to a lack of cooling water. In each case, power generators can be required to curtail power generation or shut down completely. Such events are not rare occurrences. One NREL report documenting thermal generator outage and curtailment events between 2000 and 2015 found there were 25 incidents in which nuclear facilities had to curtail output or shut down operations because intake water was too warm, discharge water was too warm, both intake and discharge water too was warm, or there was a lack of intake water.[26] It's likely that these incidents will continue in both frequency and intensity as 61% of nuclear capacity in the lower 48 states is expected to face medium-high to extremely high water stress by the year 2030.[27]

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[24] *See* Questions for the Record Submitted to Mr. Andrew Ott, U.S. Senate Committee on Energy and Natural Resources, January 23, 2018 Hearing: The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone at 10, 2019.

[25] Climate Central, "Heat and Drought Pose Risks for Nuclear Power Plants," July 18, 2012.

[26] McCall, Macknick, and Hillman, *Water-Related Power Plant Curtailments: An Overview of Incidents and Contributing Factors*, at 8, December 2016.

[27] Whieldon and Kuykendall, "Climate Change Poses Big Water Risks for Nuclear, Fossil-Fueled Plants," October 21, 2020.

III. Conclusion

The interconnectedness of our power grid is one of its greatest attributes. Interregional transmission can help keep power flowing when widespread, unplanned generation outages occur, as demonstrated by the extreme weather event examples described above. As planners, stakeholders, states, and regulators consider how to plan for the grid of the future, it should consider these common mode failures and should incorporate them into regional and interregional planning.

Attachment 2

Transmission Makes the Power System Resilient to Extreme Weather
by Grid Strategies LLC (July 2021)

TRANSMISSION MAKES THE POWER SYSTEM RESILIENT TO EXTREME WEATHER

Grid Strategies LLC

ACORE
AMERICAN COUNCIL ON RENEWABLE ENERGY

PREPARED FOR ACORE, WITH SUPPORT FROM THE MACRO GRID INITIATIVE

AUTHOR
MICHAEL GOGGIN
Grid Strategies LLC

JULY 2021

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This February, millions of Americans experienced prolonged power outages when electricity demand exceeded supply as record cold gripped much of the Central U.S. Power outages are always life-threatening for those who rely on electric medical devices, but they can be dangerous for anyone during a period of extreme cold or heat. Tragically, it appears the February power outages contributed to hundreds of deaths in Texas alone.[1] Electricity is also increasingly the lifeblood of America's economy, and is essential for powering first responders and national security workers. The Congressional Research Service estimates that weather-related power outages cost Americans $25-70 billion annually.[2]

Investigations are underway to determine what caused February's outages. Regardless of which energy sources failed, strengthening transmission is an essential part of the solution for preventing future outages. 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. This is primarily due to heating/cooling needs and supply, including changes in wind and solar output as well as failures of conventional power plants due to extreme weather.

Many severe weather events migrate from region to region, allowing one region to import during its time of need and then export to other regions once the storm moves on. Grid operators have confirmed that connecting large geographic areas via transmission saves billions of dollars per year by reducing the need for power plant capacity by reducing variability in electricity supply and demand.[3] A strongly integrated grid network also provides valuable resilience, so if some power lines or power plants are taken offline by any type of disaster, there are alternative sources of power available.

1 Peter Aldhous, Stephanie M. Lee, and Zahra Hirji, "The Texas Winter Storm and Power Outages Killed Hundreds More People Than the State Says," (May 26, 2021), available at: https://www.buzzfeednews.com/article/peteraldhous/texas-winter-storm-power-outage-death-toll.

2 Executive Office of the President, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*, (August 2013), available at: https://www.energy.gov/sites/default/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf.

3 For example, see PJM, "PJM Value Proposition," (2019) available at: https://www.pjm.com/about-pjm/-/media/about-pjm/pjm-value-proposition.ashx, MISO, "Value Proposition," (n.d.), available at: https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/.

EXECUTIVE SUMMARY

Severe weather events are becoming more common and more extreme, with severe events challenging nearly every part of the U.S. power grid in the last decade alone.[4] This analysis reviews five recent severe weather events to determine the value additional transmission would have provided.

February 2021 Winter Storm Uri — Each additional 1 GigaWatt (GW) of transmission ties between the Texas power grid (ERCOT) and the Southeastern U.S. **could have saved nearly $1 billion, while keeping the heat on for hundreds of thousands of Texans**. With stronger transmission ties, other parts of the Central U.S. also could have avoided power outages while saving consumers hundreds of millions of dollars. In particular, consumers in the Great Plains, served by the Southwest Power Pool (SPP), and those in the Gulf Coast states, served by the southern part of the Midcontinent Independent System Operator (MISO), **each could have saved in excess of $100 million** with an additional 1 GW of transmission ties to power systems to the east.

Texas heat wave in August 2019 — An extended heat wave in Texas led to high power prices across 12 days in August 2019. An additional 1 GW transmission tie to the Southeast could have **saved Texas consumers nearly $75 million**. As summer heat waves become more frequent and severe, the value of transmission for delivering needed electricity supplies from regions that are less affected will grow.

The "Bomb Cyclone" cold snap across the Northeast in December 2017-January 2018 — New England, New York, and the Mid-Atlantic region suffered cold weather for nearly three weeks, causing natural gas price spikes and nearly exhausting fuel oil supplies in New England. **Each of these regions could have saved $30-40 million** for each GW of stronger transmission ties among themselves or to other regions. These regions routinely switched between importing and exporting as the most severe cold migrated among the regions over the course of the three-week event, demonstrating that transmission benefits all users across broad geographic areas. In addition, one GW of stronger transmission ties between eastern and western PJM, the grid operator for much of the region between the Mid-Atlantic and Chicago, would have provided over $40 million in net benefits during this event.

4 See, e.g. NOAA National Centers for Environmental Information, "Billion-Dollar Weather and Climate Disasters: Overview," (2021), available at: https://www.ncdc.noaa.gov/billions/.

The January 2014 "polar vortex" event in the Northeast — New England, New York, and the Mid-Atlantic region suffered several days of extreme cold in early January 2014. The grid operator for the Mid-Atlantic region, PJM, resorted to voltage reductions to avoid the need for rolling outages. **Greater transmission ties within and among these regions could have saved consumers tens of millions of dollars and prevented reliability concerns.** Like the 2017/2018 Bomb Cyclone event, regions switched between importing and exporting as the most extreme cold migrated from region to region.

The "polar vortex" event in the Midwest in 2019 — While an additional 1 GW of transmission between MISO and PJM would have only saved a few million dollars during this short-lived cold snap, this event was notable for illustrating how transmission expansion benefits both interconnected regions. As the extreme cold moved eastward from MISO to PJM, so did the high power prices, and transmission flows switched from westward to eastward.

These results for these five events are summarized in the table below. For reference, long-distance transmission costs around $700 million per GW of transfer capacity, based on the average cost for the 18 above-ground shovel-ready projects identified in a recent report, though costs vary considerably based on the length of the line and other factors.[5] In the case of the February 2021 Texas outages, the value of power delivered to Texas could have fully covered the cost of new transmission to the Southeast, while for other lines and severe weather events the value could have defrayed a significant share of the cost of building transmission.

TABLE 1. *Value of 1 GW of additional transmission by region for each event*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
WINTER STORM URI, FEBRUARY 2021	
ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82
TEXAS HEAT WAVE, AUGUST 2019	
ERCOT – TVA	$75
NORTHEAST BOMB CYCLONE, DECEMBER 2017 – JANUARY 2018	
Eastern PJM (VA) – Western PJM (Northern IL)	$43
NYISO – PJM	$41
PJM – MISO	$38
NYISO – ISONE	$29
NORTHEAST POLAR VORTEX EVENT, JANUARY 2014	
PJM – MISO	$17
NYISO – PJM	$9
NYISO – MISO	$21
MIDWEST POLAR VORTEX EVENT, JANUARY 2019	
MISO – PJM	$2

For each event, the savings across the multiple potential new lines are not always additive, with the total savings tending to be somewhat lower than the sum of all lines' savings. This is because building the first line into a region will alleviate some of the congestion, reducing the value of additional lines into that region.

5 Michael Goggin, Rob Gramlich, and Michael Skelly, *Transmission Projects Ready to Go: Plugging Into America's Untapped Renewable Resources*, (April 2021), available at: https://cleanenergygrid.org/wp-content/uploads/2019/04/Transmission-Projects-Ready-to-Go-Final.pdf.

Across these events, transmission congestion tends to recur at certain notable points on the grid, confirming the need for expanded transmission in those areas. Expanding transmission between ERCOT and the Southeast, from SPP and MISO to power systems to the east like PJM and the Southeast, between western and eastern PJM, and among eastern PJM, New York, and New England appears to be particularly valuable for protecting against the impact of severe weather.

These events demonstrate that all generation sources are vulnerable to severe weather, making increased transmission to broaden the pool of available resources one of the best options for increasing resilience. ERCOT[6] and SPP[7] data for the February 2021 event show that coal, gas, diesel, wind, solar, nuclear, and hydropower plants were all taken offline by the record cold and ice; however, gas generators accounted for the majority of outages, with the cold causing generator equipment failures as well as fuel interruptions due to overwhelmed pipeline capacity and frozen gas wells.

Despite the large savings identified above, transmission's value for making the grid more resilient against severe weather and other unexpected threats is not typically accounted for in transmission planning and cost allocation analyses. Grid operator transmission planning processes typically assume normal electricity supply and demand patterns, and in most cases do not account for the value of transmission for increasing resilience. Transmission's hedging or insurance value from protecting consumers against the economic and reliability impacts of these rare events is also not typically accounted for.

As a result, pro-transmission policies need to be enacted to account for the resilience benefits of transmission. Just as President Eisenhower created the interstate highway system to protect national security and facilitate interregional trade, there is a clear national interest in ensuring that the backbone of the 21st century economy — the power grid — is strong and secure.

6 ERCOT, "Hourly Resource Outage Capacity," (2021), available at: http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13103&reportTitle=Hourly%20Resource%20Outage%20Capacity&showHTMLView=&mimicKey.

7 SPP, "Capacity of Generation on Outage," (2021), available at: https://marketplace.spp.org/pages/capacity-of-generation-on-outage#%2F2021%2F02.

Federal legislation and action by the Federal Energy Regulatory Commission (FERC) can enable the needed investment. A tax credit for building high-voltage transmission lines is now under consideration in Congress. FERC can require greater regional and interregional coordination in how transmission is planned and paid for, and could require minimum levels of interregional transmission to ensure grid reliability. Congress could also pass legislation directing FERC to make those changes.

A stronger grid will be valuable every day, not just during extreme weather events. Many of the new transmission lines that would have been highly valuable during these severe weather events are the same ones needed to deliver the Midwest's low-cost wind resources to electricity demand centers to the east. Power can flow in both directions on transmission, so both ends of the line benefit. Most of the time these lines will export wind generation from the Midwest, but during an emergency power can flow back into the Midwest.

Many recent studies show that interregional transmission lines like those discussed in this paper become increasingly essential as wind and solar penetrations increase in different parts of the country. Just as these lines aggregate diverse sources of electricity supply and demand to balance out localized disruptions during extreme weather, they provide a similar value by canceling out local fluctuations in wind or solar output.[8]

There have also been other extreme temperature and severe weather events in other regions over the last decade in which stronger transmission ties would have been similarly valuable.[9] However, those events occurred in regions without centralized power markets or in regions that were not adjacent to those with centralized power markets, making it more difficult to quantify the value of transmission due to the lack of transparent market price information. It is likely that these regions could have seen benefits from transmission expansion that are comparable to those quantified in this report.[10] The following section discusses in more detail the value additional transmission could have provided during the five recent severe weather events.

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8 For example, *see* Patrick Brown and Audun Botterud, "The Value of Interregional Coordination and Transmission in Decarbonizing the US Electricity System," (January 20, 2021), Joule, Volume 5, Issue 1, at 115-134, available at: https://www.sciencedirect.com/science/article/abs/pii/S2542435120305572?dgcid=author; Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, (December 15, 2020), available at: https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf; Aaron Bloom et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, (October 2020), available at: https://www.nrel.gov/docs/fy21osti/76850.pdf; NREL, Renewable Electricity Futures Study," (2012), available at: https://www.nrel.gov/docs/fy13osti/52409-ES.pdf; Christopher Clack, Michael Goggin, Aditya Choukulkar, Brianna Cote, and Sarah McKee, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, (October 2020), available at: https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf.

9 For example, many parts of the Western U.S. have experienced record heat or cold, or natural gas supply interruptions like the Aliso Canyon leak and British Columbia pipeline explosion, that resulted in power outages or extreme price spikes. See, e.g. outages and price spikes in the Southwest following extreme cold and gas supply interruptions, FERC and NERC Staff, *Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations*, (August 2011), available at: https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf. Similarly, many utilities in the Southeast have been challenged by unusual cold snaps or extreme heat and drought. See, e.g. FERC and NERC Staff, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, (July 2019), available at: https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf.

10 For example, in August 2020 California experienced power outages and high prices when a high level of generator outages coincided with record-breaking heat across many parts of the Western U.S. While this event was highly unusual in that the extreme heat affected much of the West at the same time, additional transmission capacity to other regions still could have helped alleviate the outages and price spikes. The California grid operator has calculated that congestion on transmission ties with other regions, mostly the Pacific Northwest, added around $45 million in consumer costs, while transmission congestion within California imposed an additional $37 million in costs.

RESULTS: VALUE OF TRANSMISSION DURING RECENT SEVERE WEATHER EVENTS

These events demonstrate that all generation sources are vulnerable to severe weather, making increased transmission to broaden the pool of available resources one of the best options for increasing resilience. Almost all severe weather events are at their most extreme in a relatively narrow geographic area, so transmission allows surplus electricity supplies to be delivered from neighboring regions that are not experiencing extreme electricity demand or loss of generating supply.

Winter Storm Uri in February 2021

The value of transmission for resilience can be seen in the drastically different outcomes of MISO and SPP relative to ERCOT during the February 2021 cold snap event. SPP and MISO were able to weather the storm with much less severe power outages thanks to stronger transmission ties to neighboring regions that allowed them to import more than 15 times as much power as ERCOT.

While SPP and MISO also experienced extreme cold, they were able to avoid major power shortfalls by importing electricity from regions experiencing milder temperatures, mostly to the east. As shown in the bottom half of the Department of Energy chart below, at maximum MISO was importing nearly 9,000 megawatts (MW) from PJM, several thousand MW from the Tennessee Valley Authority (TVA), and around an additional 1,000 MW each from Southern Company, Louisville Gas and Electric, and Canada.[11] Total MISO imports were consistently over 13,000 MW during the most challenging period from midday February 15 to midday February 16.

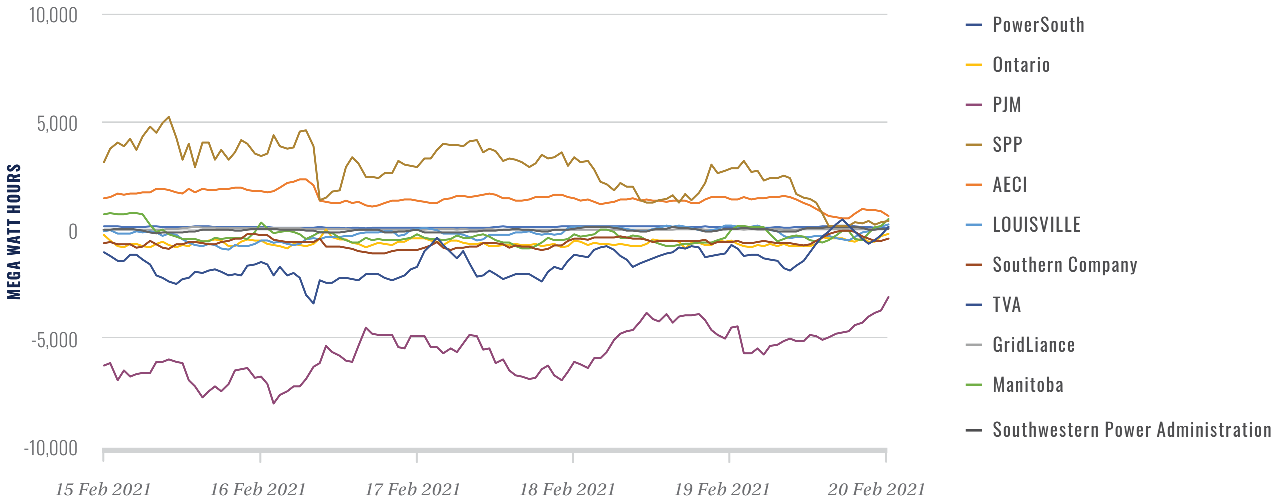

FIGURE 1. *Midcontinent Independent System Operator, Inc. (MISO) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time*

In turn, MISO was exporting to power systems to its west, delivering over 5,000 MW to SPP and nearly 2,500 MW to the Associated Electric Cooperative Incorporated, as shown in the top part of the chart. Thus around half the power MISO was importing was effectively flowing through MISO to reach power systems farther to the west.

In contrast to the 13,000 MW MISO was importing during the peak of last month's event, ERCOT was only able to import about 800 MW of power throughout the event, as shown below. ERCOT was initially able to import nearly 400 MW from Mexico, though those imports were cut early on February 15 when Mexico also experienced generator outages due to a loss of gas supply. Imports from SPP were also briefly cut at various points as SPP experienced its own shortages, particularly on February 16.

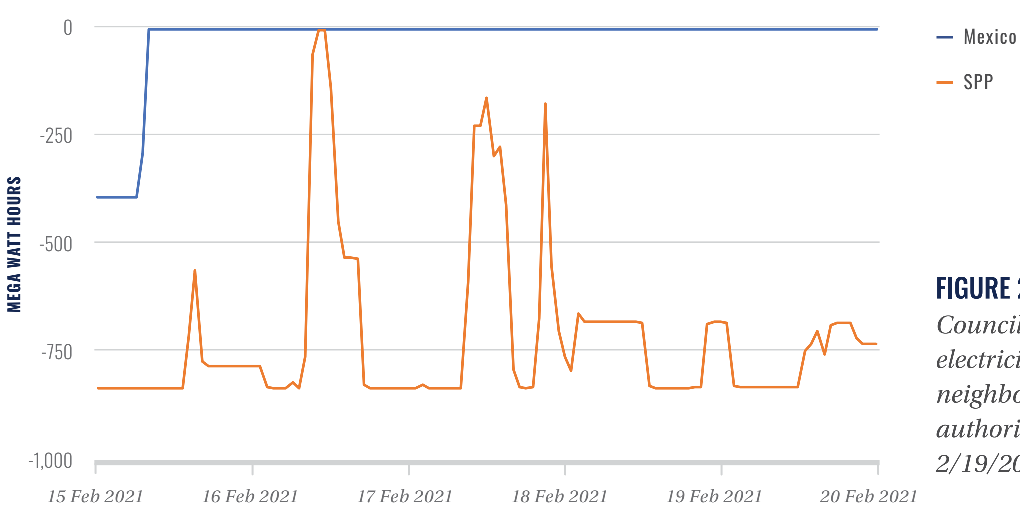

FIGURE 2. *Electric Reliability Council of Texas, Inc. (ERCOT) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time*

MISO and SPP also could have benefited from stronger transmission ties to neighboring regions, as well as stronger ties between northern and southern MISO. Power prices in SPP and southern MISO spiked during the event, reaching or exceeding the $1,000/MWh price cap in those markets as prices for natural gas spiked.[12] The need for more transmission capacity was also reflected in the strong west-to-east price gradient across MISO and PJM shown below, with prices in the hundreds of dollars per MWh in MISO versus around $50/MWh in eastern PJM on the morning of February 15.

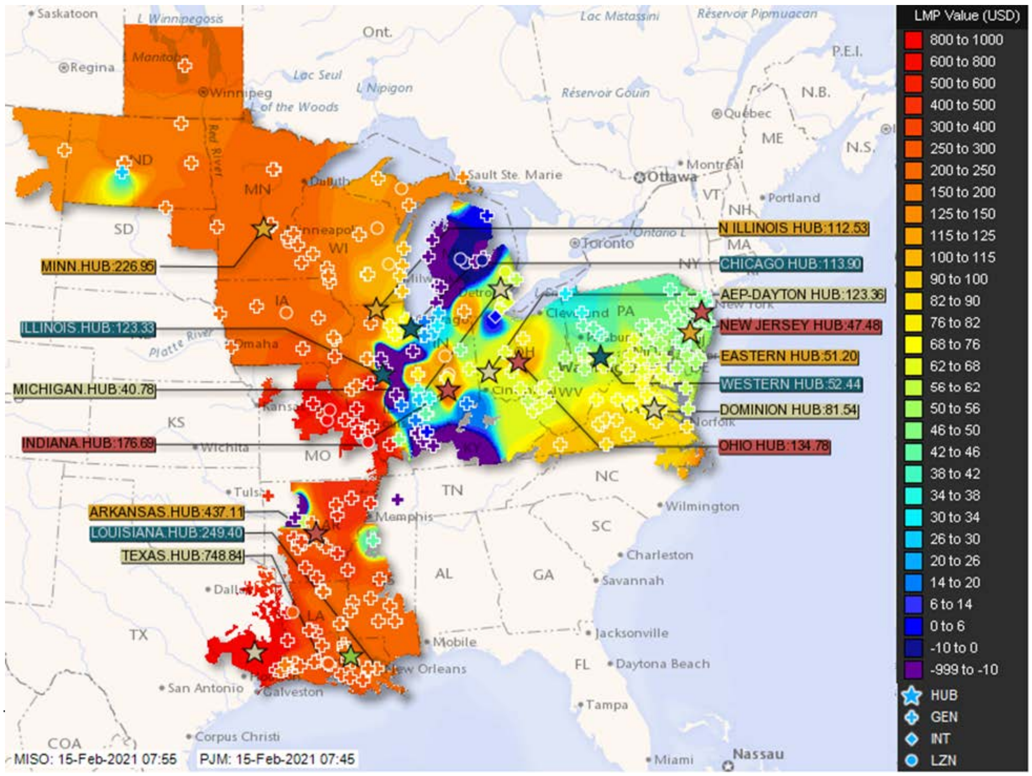

FIGURE 3. *Snapshot of power prices on the morning of February 15, 2021*

Transmission congestion costs at the seams between PJM, MISO, and SPP routinely approached $2,000/MWh throughout the event, reflecting the need for more transmission.[14] In many cases those costs flow to consumers who are forced to buy more expensive power because there was insufficient transmission capacity to deliver lower-cost imports. As is often the case, a large amount of transmission congestion at the MISO-PJM seam in Illinois and Indiana prevented more power from reaching SPP and MISO. Grid-enhancing technologies that allow more power to be transferred across transmission lines likely would have reduced the outages and price spikes in MISO and SPP.[15] Long-standing operational issues at the seams between the markets may have also contributed to the congestion and caused the localized pockets of very low

12 SPP, "Order 831 Verification Frequently Asked Questions," (April 1, 2021), available at: https://www.spp.org/documents/64402/spp%20mmu%20order%20831%20verifcation%20faq%20v4.pdf.

13 Screenshot taken February 15, 2021, from Joint and Common Market Contour Map, available at https://www.miso-pjm.com/markets/contour-map

14 MISO, "SRW Hourly Market-to-Market Settlements," (2021), available at: https://docs.misoenergy.org/marketreports/M2M_Settlement_srw_2021.csv.

15 T. Bruce Tsuchida, Stephanie Ross, and Adam Bigelow, *Unlocking the Queue With Grid-Enhancing Technologies,"* (February 1, 2021), available at: https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

prices along the seam shown in the map above.[16]

Throughout the event, transmission constraints within MISO were also limiting the transfer of power from areas with more abundant power to areas with higher prices. The quantity and price impact of binding transmission constraints within MISO were at least an order of magnitude higher than a typical winter day.[17] Price differences between northern MISO and southern MISO were also extreme throughout the event, routinely hitting $500/MWh.[18]

The following chart shows our analysis of the extreme price differences among these neighboring grid areas during Winter Storm Uri, illustrating the value of expanding transmission ties among these regions. Power prices in PJM, TVA, and MISO Illinois remained relatively low throughout the event, while prices in ERCOT were consistently high. Interestingly, power prices in SPP South and MISO South were minimally or even negatively correlated throughout much of the event, indicating that increased transmission capacity could have significantly benefited both regions. About two-thirds of our calculated $110 million in savings per GW of increased transmission between those regions would have accrued to SPP ($72 million), while one-third would have accrued to MISO ($38 million). As discussed below, it is common for transmission to benefit both ends of the transmission line over the course of many severe weather events, as the area of the most severe weather often migrates over time.

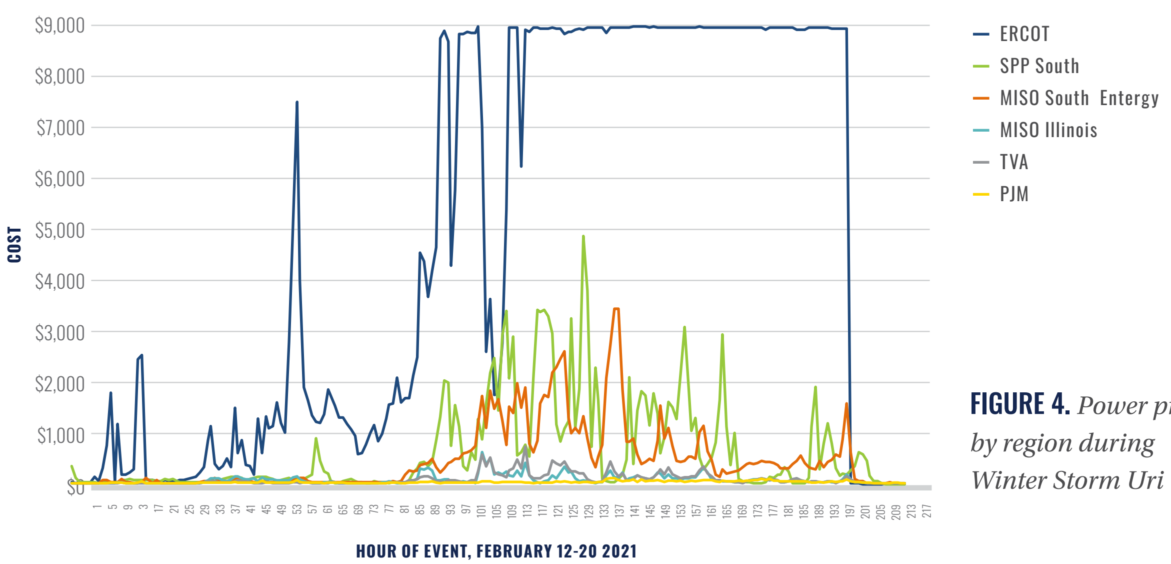

FIGURE 4. *Power prices by region during Winter Storm Uri*

16 David Patton and Mike Wander, "Identification of Seams Issues for OMS/SPP RSC," (March 19, 2021), available at: https://www.spp.org/documents/59674/oms_rsc_seamsissuesmemo.pdf.

17 MISO, "Real-Time Binding Constraints," (2021), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AReal-Time%2FMarketReportName%3AReal-Time%20Binding%20Constraints%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc.

18 MISO, "Real-Time Binding Sub-Regional Power Balance Constraints," (2021), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AReal-Time%2FMarketReportName%3AReal-Time%20Binding%20Sub-Regional%20Power%20Balance%20Constraints%20(csv)&t=10&p=0&s=MarketReportPublished&sd=desc.

Additional Transmission Could Have Alleviated Price Spikes and Kept the Heat on During Uri

More transmission capacity from ERCOT, MISO, and SPP to power systems to the east, such as PJM and TVA, and between northern MISO and southern MISO, and could have greatly alleviated these price spikes. Using the methodology described in the Appendix, our analysis finds large consumer savings for each potential 1 GW addition of transmission capacity, with savings approaching $1 billion for 1 GW of additional ties between ERCOT and the Southeast, and over $100 million for most of the other lines.

TABLE 2. *Savings per additional GW of transmission, February 12-20, 2021*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82

Because ERCOT, MISO, and SPP were all forced to resort to rolling power outages during this event, the value of transmission is not only measured in dollars. A stronger transmission network could have kept the heat and power on for millions of homes and businesses, avoiding devastating loss of life and property. ERCOT says that one MW powers 200 homes during times of peak usage, so each additional 1 GW of transmission could have kept the lights on for around 200,000 Texas homes. The total electricity shortfall in ERCOT was around 10-20 GW during February's event, so multiple high-capacity transmission lines could have greatly alleviated the pain inflicted by the outages. Because many of the gas generator failures in ERCOT were due to interdependencies between the electric system and the gas supply system, like the use of electricity to power pipeline compressors and wellhead equipment, it is possible that several high-capacity transmission lines could have entirely prevented the power outages. Transmission also helps to protect national security. During Winter Storm Uri, several military bases were forced to close due to a loss of power, or the loss of water service when water utilities lost power.[19]

Transmission projects have been proposed for many of the interregional paths identified in the table above. Pattern Energy has proposed the 2 GW Southern Cross transmission line between ERCOT and Southeastern power systems like TVA. FERC and Texas regulators have determined that this line would not interfere with ERCOT's independence from FERC regulation, so those

19 Rose L. Thayer, "Winter Weather Causes More Than a Dozen Military Bases to Close," (February 16, 2021), available at: https://www.stripes.com/news/us/winter-weather-causes-more-than-a-dozen-military-bases-to-close-1.662417.

concerns should not prevent the construction of this or other transmission between ERCOT and FERC-regulated power markets.[20] Our analysis showing nearly $1 billion in savings per GW of transmission indicates that, had Southern Cross been in service during Winter Storm Uri, it could have provided nearly $2 billion in value by delivering 2 GW from the Southeast to ERCOT for the duration of the event. This value greatly exceeds the $1.4 billion estimate cost for the transmission project in this single event, without even considering the additional billions of dollars in benefits it would provide over the many decades of the project's life.[21]

Other proposed lines would have benefited SPP and MISO. Grain Belt Express, originally developed by Clean Line and now owned by Invenergy, is proposed to run between SPP South and PJM. The Clean Line Plains and Eastern line, the Oklahoma portion of which is now owned by NextEra Energy, would have connected SPP South with the Southeast. MISO's transmission planning processes routinely examine stronger transmission ties between northern and southern MISO, and studies have shown significant value for transmission between SPP, MISO, and PJM. Unfortunately none of those lines have been built, primarily due to disagreements over who should pay for the transmission.

Those two lines could have provided hundreds of millions of dollars in benefits during Winter Storm Uri alone. While that is not enough to cover the full cost of those transmission lines, it adds to the savings they provide during normal operations. Across the half century or longer life of a typical transmission line, it is almost certain that the line will provide critical supplies of power during at least one severe weather event — particularly with the frequency and magnitude of severe weather increasing. Accounting for resilience benefits in transmission planning and cost allocation would significantly increase the calculated benefit-to-cost ratio of transmission, enabling more transmission projects to move forward.

The experience of MISO and SPP during February's Winter Storm Uri likely would have been even worse had they not made large internal investments in transmission over the last decade.

During a recent MISO Board meeting, MISO President Clair Moeller stated that the Multi-Value Project transmission lines that his organization has built over the last decade, at a cost of around $6.5 billion,[22] provided around $18 billion in benefits across three days of Winter Storm Uri.[23]

20 Pattern Energy, "Pattern's Southern Cross Transmission Project Receives Key FERC Approvals," (December 19, 2011), available at: https://www.prnewswire.com/news-releases/patterns-southern-cross-transmission-project-receives-key-ferc-approvals-135852828.html.

21 *Southern Cross Transmission LLC*, Direct Testimony of David Parquet on Behalf of Southern Cross Transmission LLC, (2017), Attachment A, 2017-UA-79, at 7, available at: https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=385777.

22 MISO, "Regionally Cost Allocated Project Reporting Analysis: 2011 MVP Portfolio Analysis Report," (January 2021), available at: https://cdn.misoenergy.org/MVP%20Dashboard%20Q4%202020117055.pdf.

23 This calculation is different from that presented in this paper, as it is based on the cost of the more extensive power outages that would have happened without recent transmission investments, at an assumed cost of around $20,000/MWh of unserved energy. In contrast, our analysis evaluates reductions in power prices with potential additional transmission.

Other severe weather events have also challenged the South Central region, though none was as severe as Winter Storm Uri. On February 2, 2011, ERCOT experienced rolling outages when cold weather similarly caused power plant outages and natural gas supply shortages. Millions of Texans experienced rolling outages that morning, and power prices hit the then-price cap of $3,000/MWh.[24] An extended heat wave in summer 2011 also challenged the power grid in ERCOT, causing high prices but no widespread outages. During another cold snap on January 6, 2014, ERCOT prices spiked to $5,000/MWh, and prices have gone even higher during other extreme temperature and severe weather events.

During other severe weather events, ERCOT could have delivered needed power to neighboring regions, reversing the flows that were seen in February 2021. MISO South, SPP South, and parts of the Southeast experienced extreme cold on January 17, 2018, causing over 14,000 MW of unexpected generation outages and bringing utilities to the brink of implementing rolling outages.[25] Stronger east-west transmission ties to ERCOT and power systems to the east, and transmission to northern SPP and MISO, could have alleviated the resulting price spikes and prevented reliability concerns.

August 2019 ERCOT heat wave

An extended heat wave in Texas led to high power prices across 12 days in August 2019. An additional 1 GW transmission tie to the Southeast could have saved Texas consumers nearly $75 million, per our calculations using the methodology described in the Appendix. As shown below, power prices in TVA and MISO South remained consistently low across the 12 days, while prices in ERCOT spiked most afternoons. Additional transmission ties to those regions, or to SPP or the Western Interconnect, could have prevented those price spikes.

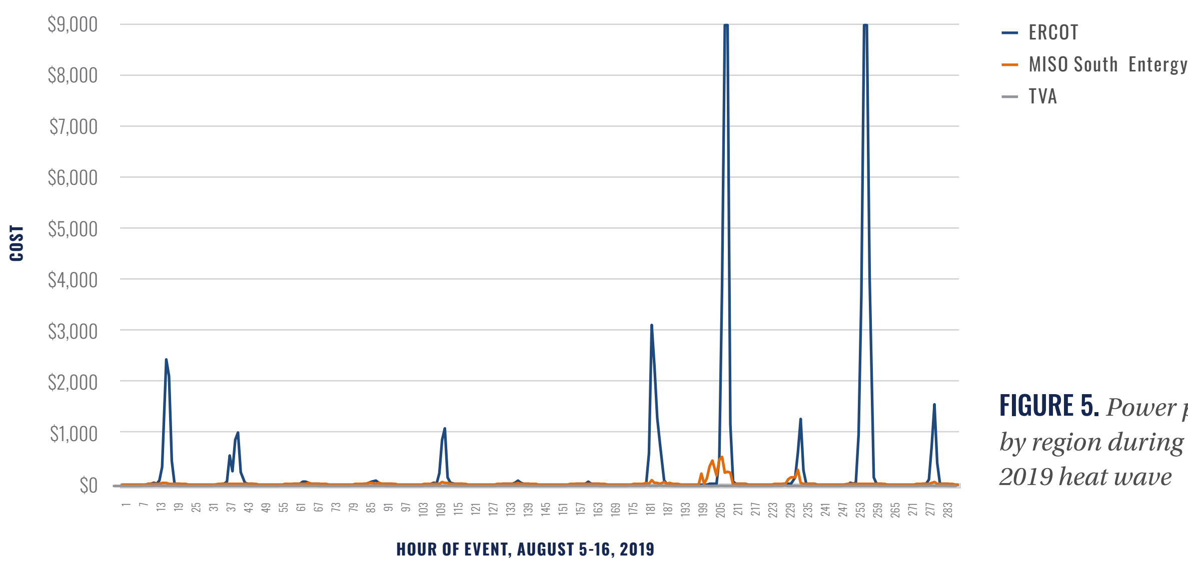

FIGURE 5. *Power prices by region during August 2019 heat wave*

24 Potomac Economics, LTD., *Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011*, (April 21, 2011), available at: http://www.ercot.com/content/meetings/tac/keydocs/2011/0505/09._IMM_Report_Events_020211.pdf.

25 FERC and NERC Staff, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, (July 2019), available at: https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf.

The “Bomb Cyclone” cold snap across the Northeast in December 2017-January 2018

New England (ISO-NE), New York (NYISO), and the Mid-Atlantic region (PJM) suffered cold weather for nearly three weeks, causing natural gas price spikes and nearly exhausting fuel oil supplies in New England. As summarized in the table below, each of these regions could have saved around $30-40 million for each GW of stronger transmission ties among themselves or to other regions. More specifically, PJM could have saved around $38 million from each GW of greater imports from MISO to its west. One GW of stronger transmission ties between eastern and western PJM also could have provided over $40 million in net benefits during this event.[26]

TABLE 3. *Savings per additional GW of transmission, December 26, 2017 – January 19, 2018*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
Eastern PJM (VA) – Western PJM (Northern IL)	$43
NYISO – PJM	$41
PJM – MISO	$38
NYISO – ISO-NE	$29

PJM, New York, and New England routinely switched between importing and exporting as the most severe cold migrated among the regions over the course of the three-week event, demonstrating that transmission benefits all users across broad geographic areas. The chart below shows how eastern PJM, New York, and New England experienced price spikes at different times during the event. New York prices were highly volatile given the relatively small size of its market and lack of transmission ties to neighboring regions. ComEd power prices, in western PJM, were consistently low throughout the event, even as power prices spiked in Virginia and other parts of eastern PJM. Largely as a result, PJM reported $900 million in internal PJM transmission congestion costs in the first half of 2018, up from $285 million in the first half of 2017.

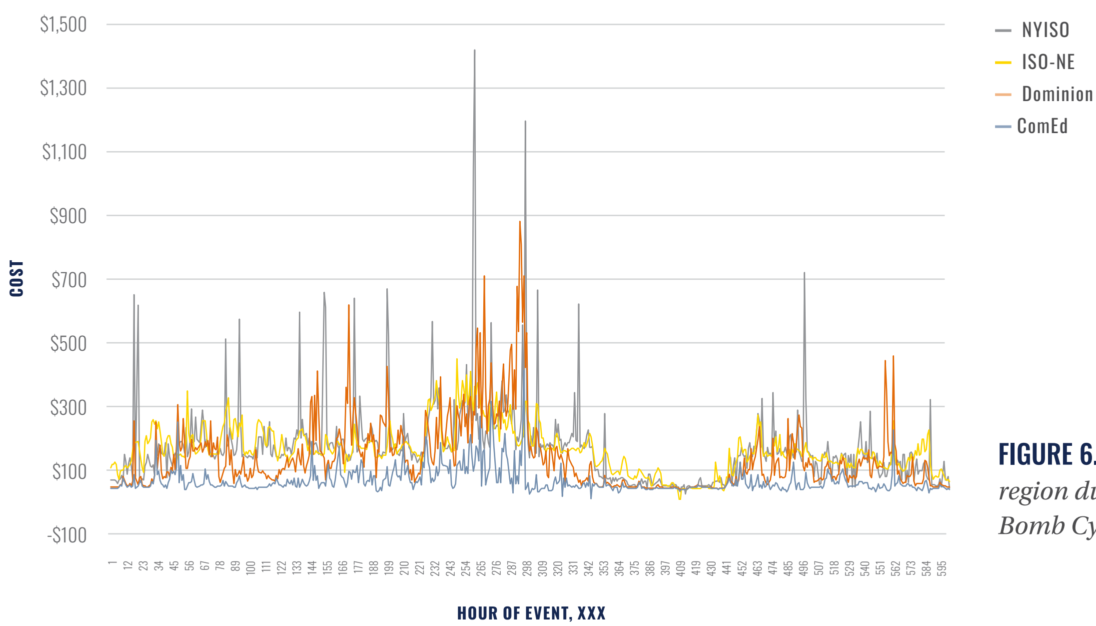

FIGURE 6. *Power prices by region during 2017-2018 Bomb Cyclone*

The January 2014 "polar vortex" event in the Northeast

The Central U.S., Northeast, and Mid-Atlantic regions suffered several days of extreme cold in early January 2014. PJM was forced to resort to system-wide voltage reductions to avoid the need for rolling outages. Greater transmission ties within and among these regions could have saved consumers tens of millions of dollars and prevented reliability concerns.

TABLE 4. *Savings per additional GW of transmission, January 5-10, 2014*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
PJM – MISO	$17
NYISO – PJM	$9
NYISO – MISO	$21

As shown below, prices were generally lower in MISO throughout the event, as the most extreme cold was located to the east in PJM and New York. Delivering power from MISO to PJM, or even to NYISO, would have greatly reduced consumer costs, as shown in the table above.

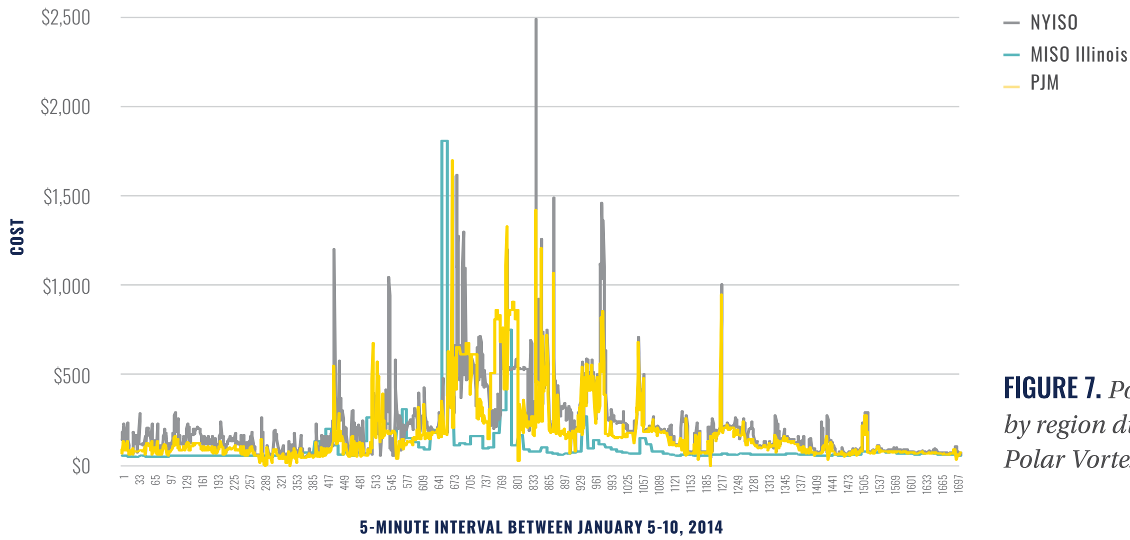

FIGURE 7. *Power prices by region during 2014 Polar Vortex*

Like in the 2017/2018 Bomb Cyclone event, regions switched between importing and exporting as the most extreme cold migrated from region to region. This trend was most apparent the morning of January 7, the day when most regions experienced the most extreme cold. As shown in the following chart that zooms in on that morning, each region moving west to east lagged the other by an hour or two in experiencing the highest prices.

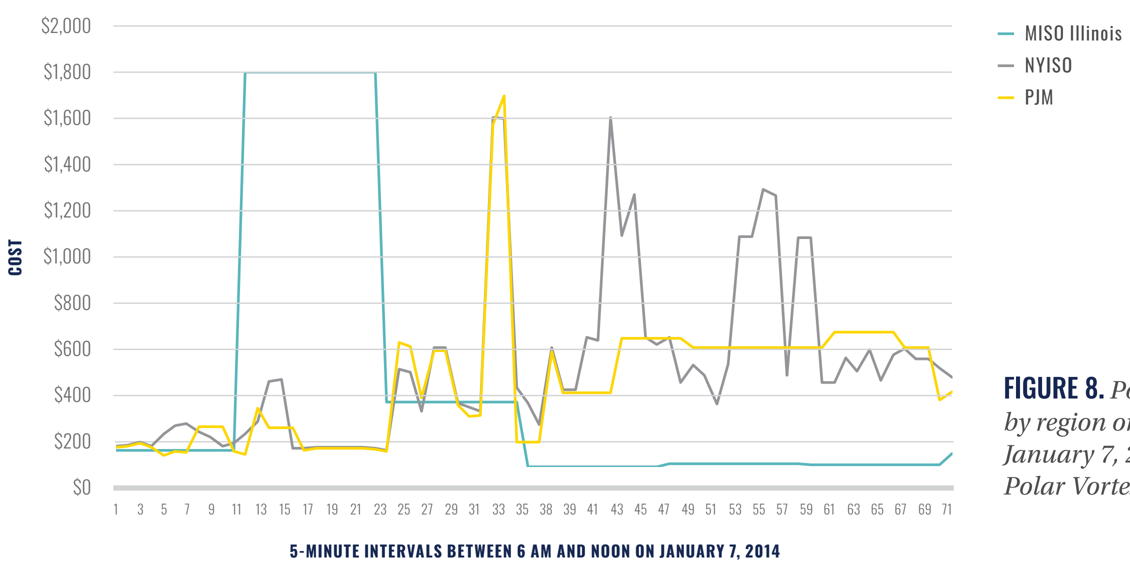

FIGURE 8. *Power prices by region on morning of January 7, 2014, during Polar Vortex*

The “polar vortex” event in the Midwest in 2019

While an additional 1 GW of transmission between MISO and PJM would have saved around $2.4 million dollars during this short-lived cold snap, this event was more notable for illustrating how transmission expansion benefits both interconnected regions. As the extreme cold moved eastward from MISO to PJM on January 30-February 1, 2019, so did the high power prices, and transmission flows switched from westward to eastward.

Early on January 30, MISO's wind output dropped off as temperatures fell below the low temperature limit for wind turbines, forcing them to shut down. Fortunately, wind output in PJM was nearly twice as high as average. This higher wind output helped PJM export in excess of 5,000 MW of power westward to the Midwest grid operator (MISO) during its time of peak demand, a reversal of the typical eastward flow of power. This shows the value of wind's geographic diversity paired with a well-connected grid, creating a more resilient overall system. Transmission also allowed MISO and PJM to take advantage of the diversity in their electricity demand patterns, in addition to the diversity in their wind output. PJM electricity demand was relatively low on the morning of January 30 when MISO experienced its peak demand, while MISO demand was lower by that evening when PJM experienced its peak demand for the day.

This lagged shift in need can be seen in the chart of power prices below. Because of the lack of correlation between PJM and MISO in both electricity supply and demand, the $2.4 million in benefits from an additional GW of transmission are evenly split between the regions.

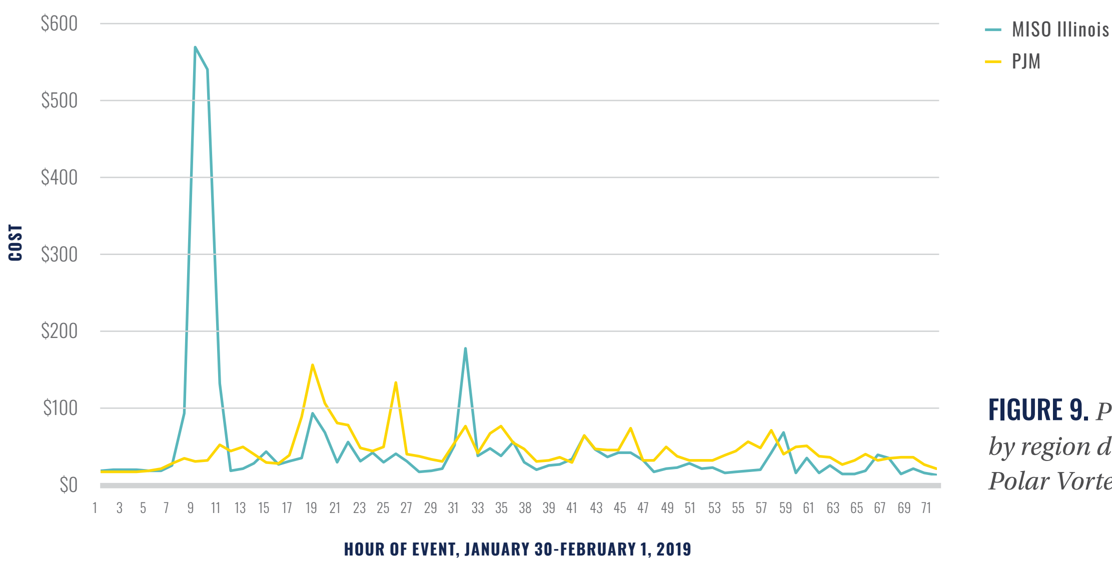

FIGURE 9. *Power prices by region during 2019 Polar Vortex*

This event also revealed other opportunities for expanding transmission to provide consumers with greater access to low-cost energy resources like wind. For example, when MISO and PJM experienced their highest electricity demand on the morning of January 31, SPP had more than 9,000 MW of wind output, keeping prices low. Similarly, electricity prices in MISO South region were consistently low throughout January 30 and 31 because that area was not as affected by the extreme cold. Stronger transmission ties within MISO and between MISO and SPP also could have benefited consumers by providing them with greater access to low-cost electricity generation.

PRO-TRANSMISSION POLICIES TO REALIZE THESE BENEFITS

Like other forms of infrastructure including roads and sewer systems, transmission is often described as a public good in that many of the benefits of transmission cannot be realized by the party making the investment. However, in many parts of the country, generation developers are required to pay for a large share of transmission upgrades. This is much like requiring a driver entering a congested highway to pay the full cost of adding another lane. Policy intervention is therefore needed to correct for the resulting underinvestment in transmission and other public goods. Grid Strategies has labeled the key areas of policy reform needed to enable greater transmission investment, the "three Ps:" planning, paying for, and permitting transmission. Potential policies to correct for the underinvestment in transmission include:

Transmission investment tax credit

A bill has been introduced by Senator Heinrich to create a tax credit to incentivize investments in high-voltage transmission lines.[27] The proposed tax credit is carefully targeted to incentivize high-voltage long-distance transmission projects that are difficult to build but provide large net benefits, but not the smaller local grid upgrades utilities are currently able to plan, pay for, and permit.

A transmission tax credit would provide large net benefits, many times greater than its cost. Many studies have documented the large net benefits of transmission,[28] though those benefits are not typically fully accounted for in transmission planning and cost allocation methodologies.[29] A transmission tax credit particularly benefits lower-income individuals, as electricity bills make up a disproportionate share of their total spending. A federal tax credit is analogous to how federal funds are used to build interstate highways — both account for how those infrastructure investments make the country more resilient against a range of threats and provide economic benefits across broad geographic areas.

27 A Bill to Amend the Internal Revenue Code of 1986 to Establish a Tax Credit for Installation of Regionally Significant Electric Power Transmission Lines, S.1016, 117th Congress, (March 25, 2021), available at: https://www.congress.gov/bill/117th-congress/senate-bill/1016/.

28 For example, see SPP, *The Value of Transmission*, (January 2016), available at: https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf; MISO, *MTEP17 MVP Triennial Review*, (September 2017), available at: https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf; PJM, *The Benefits of the PJM Transmission System*," (April 16, 2019), available at: https://pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.ashx?la=en.

29 Judy Chang, Johannes Pfeifenberger, and Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, (July 2013), at v, available at: https://cleanenergygrid.org/uploads/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf; Judy Chang, Johannes Pfeifenberger, Samuel Newell, Bruce Tsuchida, and Michael Hagerty, Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process, (October 2013), Appendix B, available at: http://files.brattle.com/files/6112_recommendations_for_enhancing_ercot%E2%80%99s_long-term_transmission_planning_process.pdf.

Anchor tenant

Legislation could be enacted to direct the federal government to directly invest in new transmission lines as an "anchor tenant" customer, and then re-sell that contracted transmission capacity to renewable developers and others seeking to use the transmission line. This would help provide the certainty needed to move transmission projects to construction and overcome what is called the "chicken-and-the-egg problem," in which renewable developers and transmission developers are each waiting for the other to go first due to the mismatch in the length of time it takes each to complete construction. The Department of Energy can also use its existing loan-making authority to provide low-cost financing to build transmission.

FERC action

The Federal Energy Regulatory Commission (FERC) has authority over how transmission is planned and paid for. FERC can use that authority to break the transmission planning and cost allocation logjams that are preventing large regional and interregional lines from being built. Specific reforms include developing workable interregional transmission planning and cost allocation methodologies, accounting for transmission's resilience benefits in planning and cost allocation, moving to proactive multi-value transmission planning, and moving away from requiring interconnecting generators to pay for most transmission upgrades. Legislation directing FERC to use these authorities could also be helpful.

FERC could also implement a reliability rule requiring a certain amount of interregional transmission. FERC oversees the North American Electric Reliability Corporation (NERC), which sets and enforces minimum standards for electric reliability. FERC or NERC could require minimum levels for interregional transmission interconnections, recognizing their value for ensuring grid reliability against a range of potential threats. NERC Standard TPL-001 already requires regions to implement solutions, including transmission additions, if their reliability planning studies indicate the system is not resilient against the loss of certain large transmission lines or power plants.[30]

FERC can also develop more workable compensation methods for grid-enhancing technologies that allow more power to be transferred across transmission lines, as this would help to alleviate the economic and reliability impacts of severe weather.

Streamlined permitting

While most authority for permitting transmission lines is held by states, federal agencies have authority over lines that cross federal lands. Steps can be taken to streamline and expedite permitting for transmission, which can currently take a decade or more.

30 NERC, *Standard TPL-001-4 – Transmission System Planning Performance Requirements*, (n.d.), available at: https://www.nerc.com/files/TPL-001-4.pdf.

TECHNICAL APPENDIX

Hourly real-time market prices were obtained from each of the RTOs (MISO,[31] PJM,[32] NYISO,[33] ISO-NE,[34] and ERCOT[35]) for the five severe weather events. Prices for the NYISO Capital zone were used to represent NYISO prices because of significant transmission congestion in the NYC-area zones of NYISO. MISO's Illinois hub was used to represent prices for MISO North, while the Caldwell pricing node in Entergy's Texas footprint was used to represent MISO South during the February 2021 Winter Storm Uri event. TVA-MISO interface prices, obtained from MISO's price dataset, were used to represent TVA prices during the February 2021 Winter Storm Uri and ERCOT 2019 heat wave events. Prices for the ComEd and Dominion zones were used to analyze the prices in western and eastern PJM during the Bomb Cyclone event. Otherwise, average LMPs across the entire RTO were used to represent prices in that RTO.

To calculate the net benefit of transmission reducing power prices by increasing supply on the receiving end of the line during these events, it is also necessary to account for the corresponding price increase caused by the increased demand on generators on the delivering end of the transmission line. The price increase on the delivering end 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. For example, the relationship between MISO electricity prices and demand during the January 2014 Polar Vortex event is shown in the chart below. Prices remain relatively low until demand exceeds 90 GW, at which point prices ramp up dramatically as demand increases. As a result, delivering an additional GW from a region with low demand will not dramatically raise prices there, while prices will be dramatically reduced in the receiving region where demand is high.

31 MISO, "Historical Annual Real-Time LMPs," (n.d.), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistorical%20Annual%20Real-Time%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc.

32 PJM, "Settlements Verified Hourly LMPs," (n.d.), available at: https://dataminer2.pjm.com/feed/rt_da_monthly_lmps.

33 NYISO, "Real-Time Market LBMP – Zonal," (n.d.), available at: https://www.nyiso.com/custom-reports?report=rt_lbmp_zonal.

34 ISO New England, "Final Real-Time Hourly LMPs," (n.d.), available at: https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/lmps-rt-hourly-final.

35 ERCOT, "Historical RTM Load Zone and Hub Prices," (n.d.), available at: http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13061&reportTitle=Historical%20RTM%20Load%20Zone%20and%20Hub%20Prices&showHTMLView=&mimicKey.

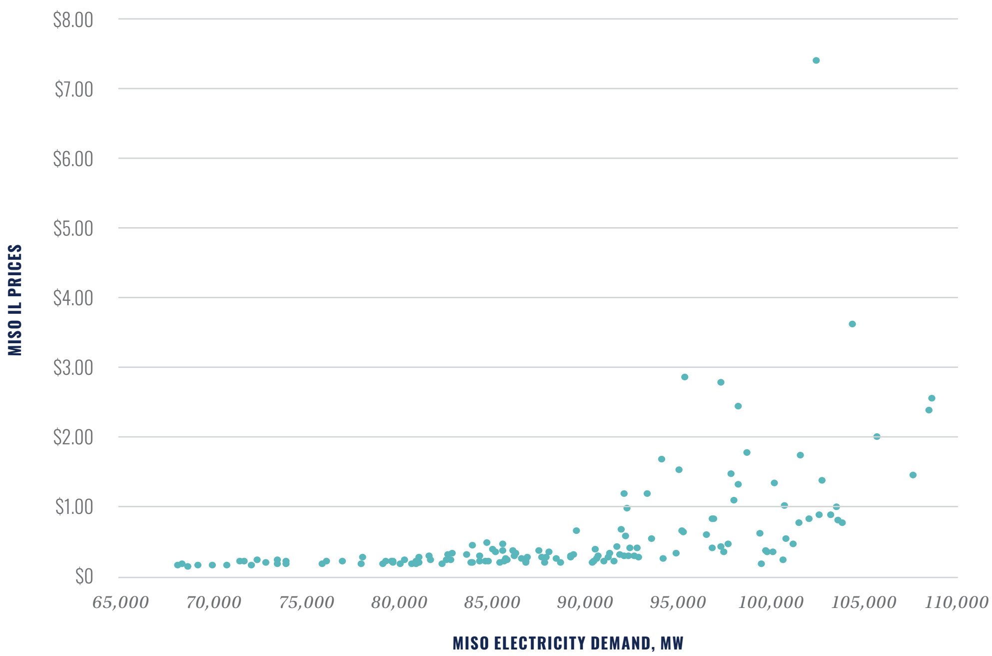

FIGURE 10. *Relationship between MISO demand and power prices during 2014 Polar Vortex*

Demand data for MISO,[36] TVA,[37] and other delivering regions were combined with the price data obtained earlier to create similar scatterplots for those delivering regions. Two linear best-fit slopes were added to each scatterplot, one on the flat part of the slope for periods of low demand, and one on the steep part of the slope for periods of high demand. For example, for the chart above, when MISO demand is greater than 90 GW, the linear best-fit slope indicates that an additional GW of demand increases prices by $15.30/MWh; however, when demand is less than 90 GW, each GW of demand increases prices by only $0.80/MWh. Those linear functions were then used to model the increase in prices in the delivering region, starting from actual demand and prices and then increasing demand by 1 GW to account for exports using the new transmission. This accounts for how increasing demand on the delivering end of the transmission slightly reduces the benefits of transmission.

36 MISO, "Historical Daily Forecast and Actual Load by Local Resource Zone," (n.d.), available at: 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.

37 EIA, "Demand for Tennessee Valley Authority (TVA), Hourly – UTC Time," (n.d.), available at: https://www.eia.gov/opendata/qb.php?category=3390009&sdid=EBA.TVA-ALL.D.H.

Attachment 3

The One-Year Anniversary of Winter Storm Uri, Lessons Learned and the Continued Need for Large-Scale Transmission
by Grid Strategies, LLC (February 13, 2022)

THE ONE-YEAR ANNIVERSARY OF WINTER STORM URI

LESSONS LEARNED AND THE CONTINUED NEED FOR LARGE-SCALE TRANSMISSION

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AUTHORS

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AND
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FEBRUARY 13, 2022

INTRODUCTION

One year after Winter Storm Uri led to an unprecedented catastrophe in Texas, it's time to revisit the causes and consequences of the grid failure there. While there were many separate reasons millions lost power for days on end, it is clear that more interregional transmission could help prevent a similar disaster in the future.

Uri also hit other states across the central U.S. hard. But unlike the main Texas grid, ERCOT, the Southwest Power Pool and Midcontinent Independent System Operator were able to import large amounts of power from their neighbors to avoid the worst of the outcomes experienced in Texas.

Texas serves as an example of the consequences of not having sufficient interregional electricity transmission. As extreme weather events become more severe and frequent, all regions are increasingly at risk of an extended outage like Texas experienced.

Transmission connections to other power regions provide a lifeline to import much needed electricity supply from areas not experiencing as extreme weather. In fact, large-scale transmission capacity provides many benefits, including:

- reducing the adverse impacts of extreme weather events like Winter Storm Uri;
- saving consumers money every day by providing them with access to lower-cost power;
- enabling more clean energy like solar and wind to be integrated onto the grid.

As just one example of the extraordinary benefits of building a better grid: an additional Gigawatt (GW) of transmission capacity can generate more than $100 million in consumer savings during an extreme weather event, defraying a significant share of its cost.

The Build Back Better legislation proposed in Congress would help spur construction of the needed interregional transmission lines. The legislation's transmission Investment Tax Credit alone could spur more than **$37 billion in new transmission development nationwide**, providing consumers with net savings of $75 billion on their electric bills. This $37 billion investment could drive more than 50 Gigawatts of new transmission lines, much larger than the major grid expansion within Texas and other central U.S. power systems last decade that enabled national wind generating capacity to nearly double.

BACKGROUND

In February 2021, Winter Storm Uri swept through Texas and other parts of the Central U.S., causing more than 4.5 million Americans to lose power for as long as four days as generating supply fell short of electricity demand. Tragically, the storm and associated power outages contributed to 246 deaths in the state of Texas alone.[1] As outlined in a joint report from the Federal Energy Regulatory Commission (FERC), North American Reliability Corporation (NERC), and Regional Entity staff, the Electric Reliability Council of Texas (ERCOT) experienced capacity[2] outages from generating units of all fuel types averaging 34,000 Megawatts (MW) for two consecutive days — nearly half of its 2021 all-time winter peak load of 69,871 MW.[3] For much of the event, generation supply on the ERCOT grid was estimated to be 10 Gigawatts (GW) short of demand.[4]

The anniversary of Winter Storm Uri is a fitting time to revisit the event. Now that the dust has settled and investigations regarding the cause and extent of the outages have been completed, it is clear that more interregional transmission connecting ERCOT to other geographic regions could have served as a lifeline to import much needed electricity supply from areas not experiencing extreme cold.

New, large-scale transmission capacity reduces the adverse impacts of extreme weather events like Winter Storm Uri, saves consumers money every day by providing them with access to lower-cost power, and enables more renewable resources to be integrated onto the grid. Despite the need for and benefits of new transmission, regionally planned transmission investment has decreased steadily over the last decade.[5] However, the Build Back Better Act (BBB) has the potential to spur new transmission construction as it includes provisions specifically aimed at overcoming the obstacles to planning and paying for large scale transmission investment. The BBB's transmission Investment Tax Credit (ITC) alone could spur over $37 billion in new transmission development, providing consumers with net savings of over $75 billion on their electric bills. The construction of interregional transmission capacity enabled by the passage of the Build Back Better Act would provide consumers with more reliable, more affordable, and cleaner power.

1 Texas Health and Human Services, "February 2021 Winter Storm-Related Deaths – Texas," December 31, 2021.

2 The FERC, NERC, and Regional Entity staff report specifies capacity in this context to be "expected" capacity: "Expected capacity includes any expected seasonal capacity derates, and for intermittent resources (e.g., wind, solar resources), expected capacity is calculated based on weather conditions." See FERC, NERC, and Regional Entity Staff, *The February 2021 Cold Weather Outages in Texas and the South Central United States*, at 8, November 2021.

3 *Id.*

4 Cramton, "Lessons from the 2021 Texas electricity crisis," March 23, 2021

5 Gramlich and Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 25, January 2021.

TRANSMISSION HELPED KEEP THE LIGHTS ON IN MISO AND SPP DURING WINTER STORM URI

A look into U.S. Department of Energy power flow transfer data during the time of the Winter Storm Uri demonstrates the reliability benefits that interregional transmission can provide. Due to a lack of interregional transmission, ERCOT was only able to import approximately 800 MW of power from the Southwest Power Pool (SPP) during the week of the cold snap, as shown in Figure 1 below.[6] SPP experienced shortfalls itself, as demonstrated by the reduction in exports to ERCOT on the 15th and 16th, which were exacerbated due to the scheduled outages of three of seven western interconnection Direct Current (DC) ties — Eddy County, Blackwater, and Rapid City.[7] ERCOT was able to import an additional 400 MW from Mexico up until the 15th, when Mexico experienced natural gas supply shortages.

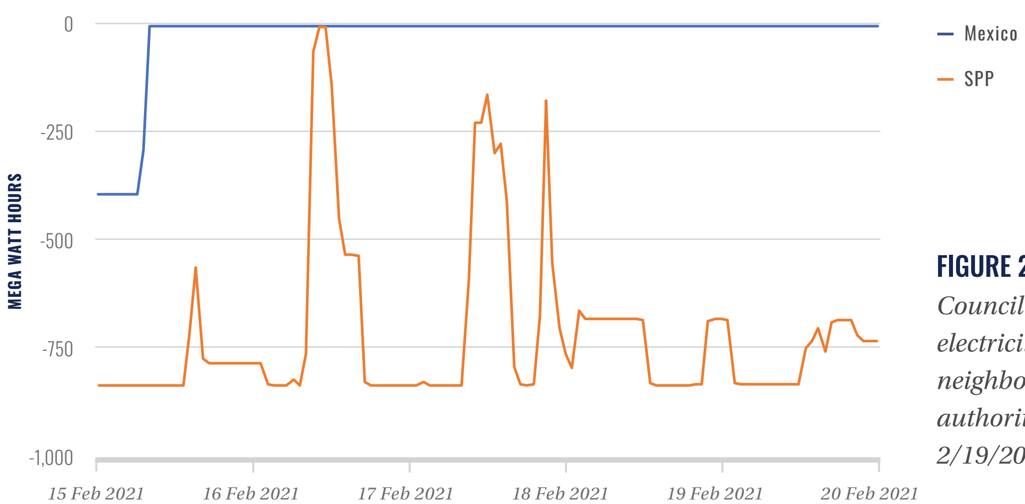

FIGURE 2. *Electric Reliability Council of Texas, Inc. (ERCO) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time*

While parts of the Midcontinent Independent System Operator (MISO) and SPP also experienced similar cold weather conditions, those RTOs were able to import electricity from other regions experiencing milder temperatures. As a result of its interregional transmission capacity, MISO was able to import a total of 13,000 MW during the peak of the event — about 15 times as much power as ERCOT was able to import. As shown in Figure 2 below, at maximum, MISO was able to import approximately 9,000 MW from PJM Interconnection, a few thousand MW from the Tennessee Valley Authority (TVA), and a combined 3,000 MW from Southern Company, Louisville Gas and Electric and Kentucky Utilities Company, and Canada. MISO was also able to export about 5,000 MW and 2,500 MW to SPP and Associated Electric Cooperative Incorporated, respectively, over the course of the cold snap.[8]

6 Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, at 8, July 2021.
7 SPP, *A Comprehensive Review of Southwest Power Pool's response to the February 2021 Winter Storm*, at 68, July 19, 2021.
8 Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, at 8, July 2021.

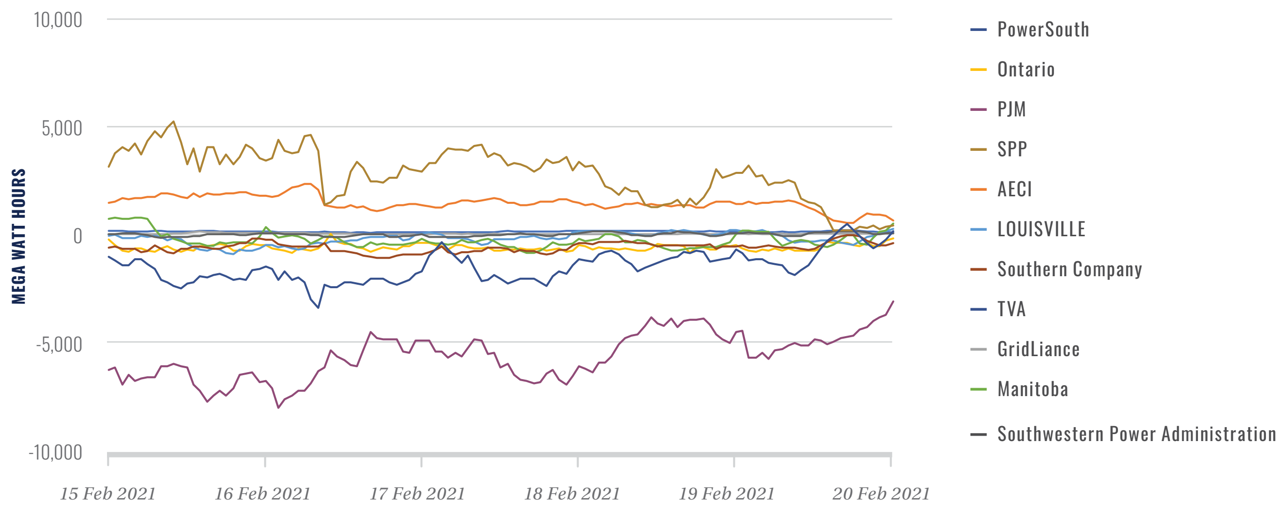

FIGURE 2. *Midcontinent Independent System Operator, Inc. (MISO) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time*

TRANSMISSION EXPANSION PROTECTS AGAINST ALL TYPES OF SEVERE WEATHER

Unfortunately, Winter Storm Uri is just the most recent extreme weather event in which expanded transmission capacity would have helped protect against localized spikes in electricity demand and outages of all generator types. These include:

- 2019 Texas heat wave led to high power prices across 12 days in August 2019;
- 2017/2018 "Bomb Cyclone" brought cold weather to the Mid-Atlantic region for nearly three weeks, causing natural gas price spikes and nearly exhausting fuel oil supplies in New England;
- January 2014 "polar vortex" event in the Northeast that caused PJM to resort to voltage reductions to avoid the need for rolling outages;
- 2019 Midwest "polar vortex" brought high electricity prices to the region.

The Congressional Research Service estimates that weather-related power outages cost Americans $25-$70 billion annually,[9] and these costs are likely to increase as severe weather becomes more common. The following chart shows that the average US customer experiences more than 4 hours of power outages per year, while states like Maine and West Virginia experience more than 12 hours of outages per year. While most outages are caused by failures on local lower-voltage electricity distribution systems, transmission system failures have been a major cause of events like the 2003 and 1965 blackouts, and have contributed to smaller

9 Executive Office of the President, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*, (August 2013).

reliability events in recent years.[10] Transmission investment makes the network stronger and more resilient by providing more alternate paths for power to reach consumers in case severe weather or another event takes out major elements of the transmission system.

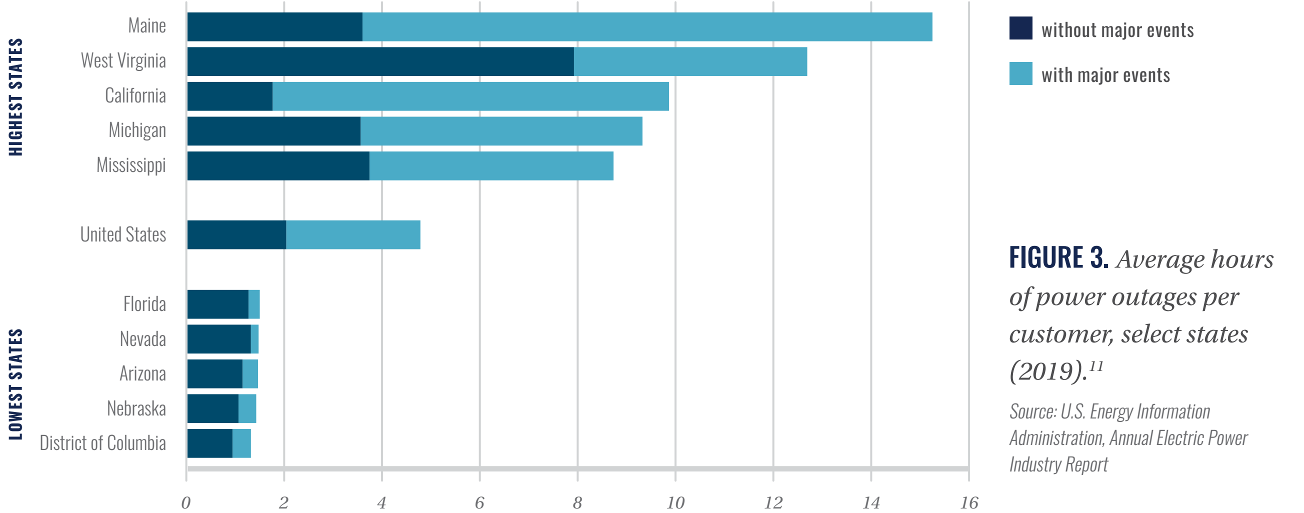

FIGURE 3. *Average hours of power outages per customer, select states (2019).*[11]

Source: U.S. Energy Information Administration, Annual Electric Power Industry Report

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10 For example, transmission outages in the Northwest contributed to the August 2020 rolling blackouts in California by limiting imports. *See* CAISO, *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, January 13, 2021.

11 U.S. Energy Information Administration, "U.S. Power Customers Experienced an Average of Nearly Five Hours of Interruptions in 2019," November 6, 2020.

TRANSMISSION BENEFITS

In addition to keeping the power on during severe weather events, transmission expansion also provides economic benefits by providing consumers with access to lower cost power. A Grid Strategies analysis evaluated the additional value additional transmission would have provided during Winter Storm Uri and other recent severe weather events. As shown in Table 1 below, an additional GW of transmission capacity during many of these events could have generated more than $100 million in consumer savings:[12]

TABLE 1. *Value of 1 GW of additional transmission by region for each recent extreme weather event*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
WINTER STORM URI, FEBRUARY 2021	
ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82
TEXAS HEAT WAVE, AUGUST 2019	
ERCOT – TVA	$75
NORTHEAST BOMB CYCLONE, DECEMBER 2017 – JANUARY 2018	
Eastern PJM (VA) – Western PJM (Northern IL)	$43
NYISO – PJM	$41
PJM – MISO	$38
NYISO – ISONE	$29
NORTHEAST POLAR VORTEX EVENT, JANUARY 2014	
PJM – MISO	$17
NYISO – PJM	$9
NYISO – MISO	$21
MIDWEST POLAR VORTEX EVENT, JANUARY 2019	
MISO – PJM	$2

12 Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, at 4, July 2021.

For reference, long-distance transmission construction costs approximately $700 million per GW of transmission capacity, based on the average cost for the 18 above-ground, shovel-ready projects identified in a recent report.[13] If a GW-scale transmission line connecting ERCOT to the Southeast, the nearly $1 billion value of power delivered to Texas just during the storm could have fully covered the cost of the transmission line. For the other weather events, the additional savings could have offset a significant share of new transmission costs.

LEVERAGING THE BUILD BACK BETTER ACT TO ENCOURAGE TRANSMISSION EXPANSION

Despite the significant reliability and regional savings benefits that large-scale transmission provides, transmission's value for making the grid more resilient against severe weather and other unexpected threats is not typically accounted for in transmission planning and cost allocation analyses. As such, federal action has the potential to spur significant, much needed transmission expansion in the U.S.

The Build Back Better Act (BBB) includes the following provisions specifically related to transmission:[14] a 30% Investment Tax Credit (ITC) for regionally significant transmission placed in service before the end of 2031, loans and grants for transmission, economic development support for host communities and technical support for siting authorities, and studies on interregional transmission. The 30% tax credit in particular has the potential to support the construction of dozens of GW of new transmission transfer capacity.[15] This transmission could reduce power sector carbon emission by nearly 150 million tons per year by bringing new low-cost wind and solar generation online.[16]

BBB would also bring significant economic benefits to consumers. The BBB's transmission Investment Tax Credit (ITC) alone could spur over $37 billion in new transmission development, providing consumers with net savings of **over $75 billion on their electric bills**. This estimate is based on the government's estimate of the impact of the tax credit[17] and analysis by regional grid operators and national laboratories indicating that every dollar invested in transmission yields around three dollars in benefits. Specifically, the Southwest Power Pool has found significant net benefits have already been realized from its recent transmission investments, with benefits expected to exceed costs by a factor of 3.5 over the lines' first 40 years.[18] The Midcontinent Independent System Operator has also found that its Multi-Value Projects offer a benefit-to-cost ratio of between 2.2 and 3.4.[19] Similarly, the National Renewable Energy

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13 Goggin, Gramlich, and Skelly, *Transmission Projects Ready to Go: Plugging Into America's Untapped Renewable Resources*, April 2021.

14 Build Back Better Act, H.R. 5376, 117TH Cong. (2021).

15 See Goggin, Gramlich, and Skelly, *Transmission Projects Ready to Go: Plugging Into America's Untapped Renewable Resources*, April 2021.

16 Based on our estimate that every $1 billion in transmission investment reduces emissions by nearly 4 million short tons of carbon per year, and the government's estimate that the tax credit will drive over $37 billion in transmission investment per the next footnote. *See* Goggin, *Electricity Transmission Is a Low-Cost Tool for Carbon Abatement*, 2021.

17 The transmission tax credit in the Build Back Better Act was scored as costing $11.279 billion, which corresponds to $37.6 billion in transmission investment receiving a 30% tax credit. Eng and Lawrence, "House-passed $1.7 Trillion Build Back Better Reconciliation Legislation; Includes $325 Billion in Green Energy Tax Incentives and More Than $92 billion in Spending to Address Robust Climate Change Goals," November 19, 2021.

18 SPP, *The Value of Transmission*, January 26, 2016.

19 MISO, MTEP17 MVP Triennial Review, September 2017.

Laboratory Interconnections Seam study found benefit-to-cost ratios of between 1.8 to 2.9 for various transmission configurations.[20] Based on the average cost of around $700 million per GW of long-distance transmission capacity, the Build Back Better Act could spur over 50 GW of additional transmission capacity.

BUILDING A STRONGER, CLEANER GRID

Federal action like the Build Back Better Act has the potential to spur regionally significant transmission investment that is a win-win-win for more reliable, more affordable, and cleaner power. Transmission expansion provides this benefit every day, but the economic and reliability benefits are particularly pronounced when severe weather or another unexpected event strikes.

20 Brinkman, Novacheck, Bloom, and McCalley, "Interconnections Seam Study: Overview," at 32, October 2020.

Attachment 4

Potential Customer Benefits of Interregional Transmission
General Electric International, Inc. (Nov. 29, 2021)

Potential customer benefits of interregional transmission

Memo to

American Council on Renewable Energy (ACORE)

Submitted by: General Electric International, Inc.

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FOREWORD

This memo was prepared by General Electric International, Inc. (GEII), acting through its Energy Consulting group, based in Schenectady, New York. Questions and any correspondence concerning this document should be referred to:

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Motivation

This memo is being provided to ACORE in support of their comments to FERC's Advance Notice of Proposed Rulemaking: *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*.

Summary: Interregional transmission can enhance grid reliability, enable consumer benefits

State governments, utilities, and large energy buyers are mandating a shift to carbon-free resources while grid reliability is simultaneously being challenged by extreme weather events. Given their cost-competitiveness compared to alternatives,[1,2] these new carbon free resources will likely be in the form of new wind and solar generation. Reliability can be maintained with high penetrations of variable renewable energy in three ways:

1) *Adequacy*: Long term supply-demand balance resilient to grid uncertainties (e.g. outages, weather)
2) *Operational*: Day-to-day supply-demand balance for all time periods
3) *Stability*: System strength to sustain voltage and frequency

California, Denmark, and SPP are examples of three regions achieving hours of renewable penetration >70% with significant ramping, and high reliance on inverter-based resources. Each of them are leaning into new reliability approaches by utilizing a menu of industry best practices. **One of the most technically impactful and cost-effective best practices they both utilize is regionalization**. Certainly, California remains challenged by the effects of extreme weather but without such regionalization, one could argue, the impacts of prior events would have been even more devastating.

GE Energy Consulting forecasts a 2035 United States that will look similar to the SPP, California and Denmark of 2020. The value of regionalization that has been validated for SPP, California and Denmark should be assessed for the broader US.

GE Energy Consulting has suggested a methodology to assess the incremental transmission requirement for a regionalized future US with higher renewables and extreme weather uncertainty. This incremental requirement would be based on a holistic assessment of three areas of reliability benefit:

1) *Operational:* Incremental interregional transmission can enable lower wind and solar curtailment which results in fuel cost savings.
2) *Adequacy:* Incremental interregional transmission can enable higher generation diversity in the face of uncertainties such as: generation, transmission or fuel outages or extreme weather events.
3) *Stability:* Incremental interregional transmission can enable greater system strength to avoid unintentional unit tripping due to fluctuations in voltage, frequency or unwanted oscillations.

[1] E.g. Lazard LCOE 15.0, https://www.lazard.com/media/451881/lazards-levelized-cost-of-energy-version-150-vf.pdf

[2] UT Austin, https://calculators.energy.utexas.edu/lcoe_map/#/county/tech (selecting for "availability zones" filter)

Today, there are limited practices in place for each region to evaluate the consumer benefits of interregional transmission on their own. Recent studies modeling the benefits of interregional transmission across the Western and Eastern Interconnects have demonstrated significant cost savings for consumers.[3,4] National-level guidance would help chart the path towards realizing the benefits of greater regionalization.

1 Decarbonization mandates are changing the energy mix

In the United States, and around the world, decarbonization mandates are driving a change in our energy mix. Countries, states, utilities, and companies are all taking on new mandates to decarbonize their operations. While the timing varies, many of these entities have some permutation of net zero carbon goals by 2050 at the latest. Indeed, many have announced more bold near-term goals by 2030 or 2040. We have summarized these goals in Figure 1 along with average electric generation mix.

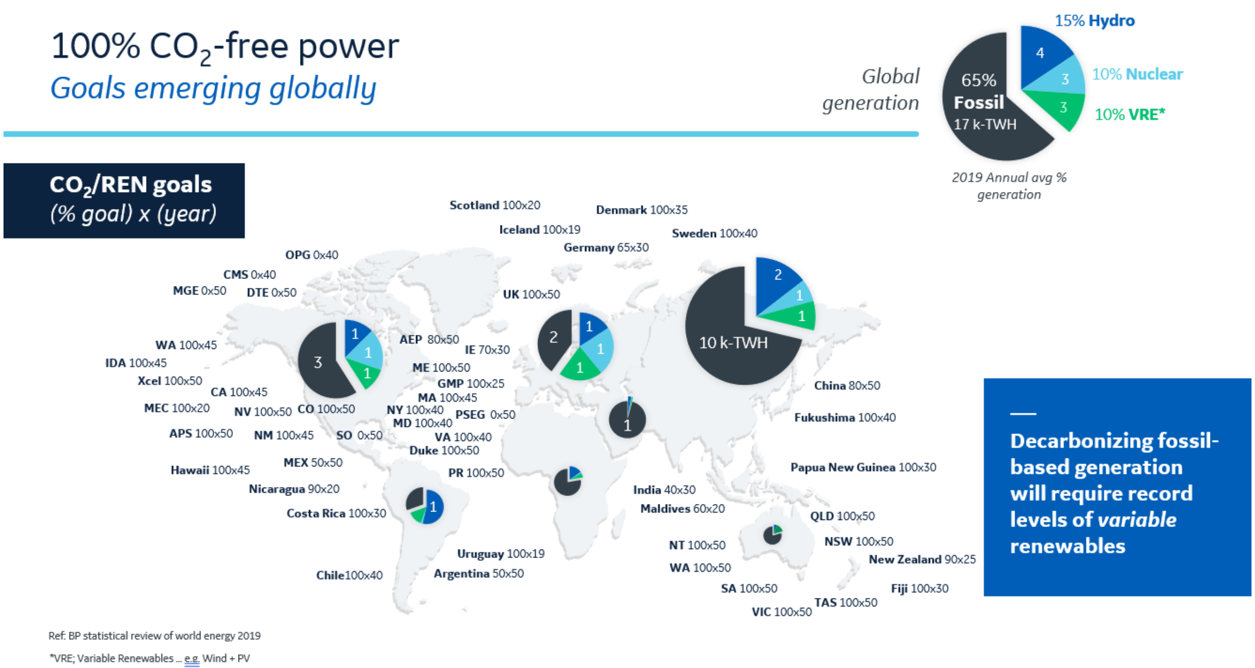


Figure 1 Global electricity generation mix along with decarbonization goals by various types of entities.

While hydro and nuclear form the majority of today's carbon-free forms of generation, given their limited availability, cost, permitting and siting challenges, the future generation mix will likely rely on

[3] Clack and Goggin, Consumer, Employment and Environmental Benefits of Electricity Transmission in the Eastern U.S., October 2020, (optimizing transmission build across the Eastern Interconnect would save consumers ~$105B through 2050), *available at* https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf

[4] Energy Strategies and the Western Interstate Energy Board, Western Flexibility Assessment, December 10, 2019 (noting that absent market coordination and increased regionalized transmission, achieving state policy targets in the 2020s becomes more difficult and costly), *available at* https://westernenergyboard.org/wp-content/uploads/2019/12/12-10-19-ES-WIEB-Western-Flexibility-Assessment-Final-Report.pdf

record amounts of new variable renewables … i.e. new wind and solar facilities. **New penetrations of wind and solar energy are central to achieving decarbonization mandates** in the electric power sector and for non-electrical carbon-emitting sectors like transportation and building heating and cooling.

2 Extreme weather events are challenging reliability

The U.S. power sector is increasingly feeling the effects of grid outages due to extreme weather. According to a recent analysis published by the US EIA, extreme events have been the main source of lost hours per customer in 2020.

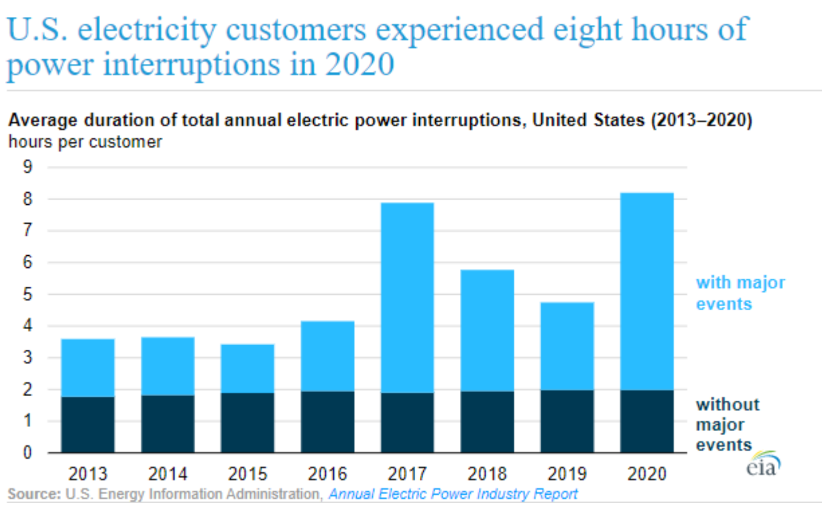


Figure 2 Analysis from the US EIA highlighting how major events accounted for six out of the eight outage hours per customer in 2020.[5]

According to the EIA, **2020 was the highest year of power interruptions since the agency began collecting data back in 2013**.[5] Notable recent storm-related outages included:

- August 2020: Louisiana & Texas—Hurricane Laura
- August 2020: Connecticut--Tropical Storm Isaias
- August 2020: Iowa derecho (extreme thunderstorm)
- August 2020: California heat wave
- October 2020: Oklahoma ice storm
- November-December 2020: Several winter storms in Maine
- February 2021: Texas freeze (Winter Storm Uri)

The key question is: **how do we continue to decarbonize our energy mix in a way that economically benefits consumers while also improving resilience to extreme weather events?**

[5] https://www.eia.gov/electricity/data/eia861/

3 Several regions are already achieving high variable renewable penetrations

While most of the world is currently below 20% variable renewables penetration, if we zoom in on the US and Europe as shown in Figure 3, we can see several examples of countries or regions that are achieving higher levels of renewables penetration.

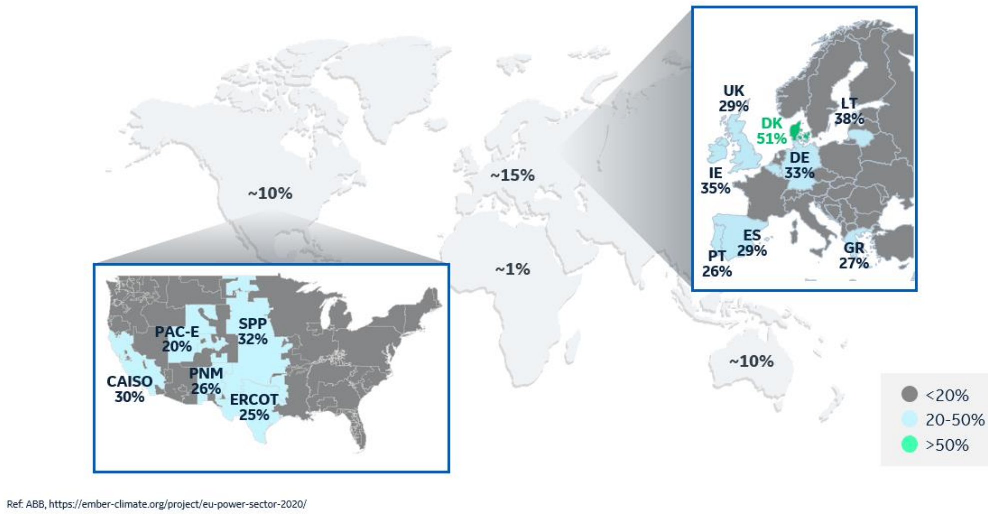


Figure 3 Average 2020 variable renewables penetration across the US and Europe.

In terms of regional penetration, Denmark has achieved 51% annual average variable renewable penetration, while several other regions across the US and Europe have achieved penetration levels in the 20-50% range. We present 2020 hourly penetrations and operations in Figure 4 for three example regions.

Potential customer benefit of interregional transmission

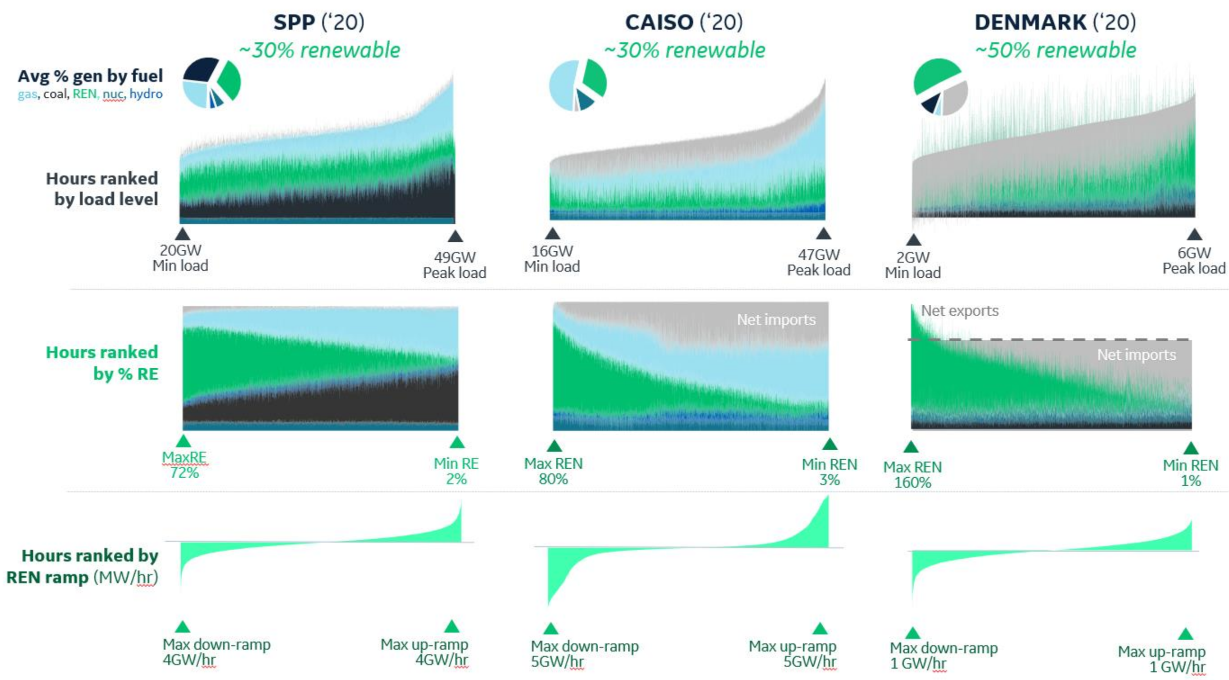


Figure 4 2020 hourly renewable penetration compared between SPP, CAISO, and Denmark.[6]

In Figure 4 and Table 1 we illustrate how hourly operations vary across systems with three different levels of variable renewable energy (VRE) penetration.

2020	PEAK LOAD	AVG %VRE	MIN HOURLY %VRE	MAX HOURLY %VRE	MAX RAMP-DOWN
SPP	49 GW	~30%	2%	72%	4 GW /hr (8% of peak)
CAISO	47 GW	~30%	3%	80%	5 GW/hr (11% of peak)
Denmark	6 GW	~50%	1%	16%	1 GW/hr (17% of peak)

Table 1 Summary of 2020 variable renewables (VRE) penetration levels across SPP, CAISO, and Denmark.[6]

Through this comparison we would like to highlight the following observations that have a direct impact on reliability:

1) **Hourly renewable penetrations can range from zero to over 100%.** In CAISO, hourly VRE penetration can be close to zero or as high as 80% while in Denmark, penetrations are even higher ranging from close to zero to ~160%.
2) **Ramping levels approach ~20% peak load levels.**

[6] ABB Hitachi

3) **Very high average VRE penetrations create periods of over/undersupply**. In the case of Denmark, we see that load levels exceed 100% or can be as low as 1%. In our forward-looking models of the US system, we see similar dynamics emerging within the next 15 years.

How do these systems maintain reliability given these new operating extremes? As we discuss further in this memo, across all three of these regions, **reliability and cost effectiveness in enabled by strong interconnections with their neighbors.**

4 Resilient decarbonization is based on three types of reliability

GE Energy Consulting has supported a wide variety of utilities and grid operators as they plan for reliable and cost-effective integration of renewables. Please see the Appendix for links to ~20 of our publicly available renewable integration study reports.

Given our broad renewable integration experiences, we observe three areas of reliability opportunity as we shift to variable renewables and maintain extreme-weather resiliency:

1. *Adequacy*: Operators are used to generators with fuel sources that are almost always available when needed. However, with the frequency of extreme weather events increasing this dynamic is changing for conventional fuel sources. Similarly, despite the availability of forecasts, wind and solar resource output is not a certainty either. How do we balance the need for adequacy and resilience with the costs to consumers? **In general, portfolio *diversity* benefits adequacy.**

2. *Operations*: Grids were designed assuming large centrally-located generation where power flows are generally flowing in a steady direction from generation centers to load centers. With the growth of highly distributed and variable wind and solar, there are reliability benefits associated with increasing flexibility. For SPP, CAISO and Denmark highlighted in Figure 4, we illustrate that the flexibility of their systems enabled renewables to reliably change their output quite dramatically in the course of one hour. **In general, resource *flexibility* provides reliability benefits to systems with higher variability.**

3. *Stability*: For the last 100 years of our electric system, stable frequency and voltage has been maintained by synchronous machines: rotating turbines that mechanically drive an electrical generator to create electricity. Wind turbines, solar panels, and batteries all drive power electronic, inverter-based electrical generators (i.e. inverter-based resources or IBRs) which provide new opportunities to maintain stable frequency and voltage. **In general, *grid strength* provides frequency and voltage stability benefits.**

5 Resilient reliability has a toolbox of solutions: cost-benefit drives choice

There is no one-size-fits-all solution. As we plan resilient decarbonized systems, **higher reliability is achieved via: 1) higher diversity; 2) flexibility; and 3) stronger grids**. Many times, a given solution can help address all three as we summarize in Table 2. In addition, implementing multiple forms of reliability enhancements can provide consumer benefits as renewable penetrations increase.

RELIABILITY ENHANCEMENTS	TYPE	ADEQUACY: *DIVERSITY*	OPERATIONS: *FLEXIBILITY*	STABILITY: *GRID STRENGTH*
Forecasting	PROCESS	✓	✓	✓
Regional coordination/visibility	PROCESS	✓	✓	✓
Geographic diversity	PROCESS	✓	✓	✓
Flexible demand	PROCESS	✓	✓	✓
Faster markets	PROCESS		✓	
Grid forming controls	PROCESS			✓
Interregional imports/exports	ASSET	✓	✓	✓
Storage	ASSET	✓	✓	✓
Lower minimum generation levels	ASSET	✓	✓	✓
Fuel-based synchronous generation	ASSET	✓	✓	✓
Synchronous condensers	ASSET			✓

Table 2 Examples of flexibility to improve diversity, flexibility and grid strength for resilient decarbonized electric systems.

The list in Table 2 represents the most common forms of reliability enhancements GE Energy Consulting recommends in our renewable integration studies. Determining which solutions are most advantageous for each region depends on the availability of solutions, their breadth of impact, along with their cost-benefit to consumers.

In general, process-related enhancements are frequently the lowest cost, and often provide all three types of reliability benefit. However, once process-related enhancements have been exhausted, exploring asset-related enhancements is imperative. Again, **implementation should be driven by the breadth of impact along with the cost to consumers.**

6 Today's best practices depend on interregional transmission & coordination

If we return to our three examples of increasing renewable penetration: SPP, CAISO and Denmark, as we show in Table 3, all three of these jurisdictions utilize reliability enhancements across the full menu of options and reliability types we presented in Table 2.

RELIABILITY ENHANCEMENTS	TYPE	SPP (~30% VRE)	CAISO (~30% VRE)	Denmark (~50% VRE)
Forecasting	PROCESS	✓	✓	✓
Interregional coordination /visibility	PROCESS	✓	✓	✓
Geographic diversity	PROCESS	✓	✓	
Flexible demand	PROCESS			
Faster markets	PROCESS	✓	✓	✓
Grid forming controls	PROCESS			
Interregional imports / exports (% of load)	ASSET	~1% (-10% -> +15%)	~40% (5% -> 70%)	~20% avg (-90% -> +80%)
Storage	ASSET		~2GW batteries[7]	

[7] https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/082621-feature-battery-storage-capacity-rapidly-rising-across-california-thermal-remains-strong

Lower minimum generation levels	ASSET	✓	✓	✓
Fuel-based synchronous generation	ASSET	✓	✓	✓
Synchronous condensers	ASSET	✓	✓	

Table 3 Examples of reliability enhancements utilized by SPP, CAISO, and Denmark.

Though this survey is not exhaustive, CAISO and Denmark represent examples of continental jurisdictions that benefit from regionalization to achieve their 2020 penetration levels. Regionalization includes:

- **Interregional transmission** build-out that is relied upon with neighboring jurisdictions. This does not necessarily imply a transfer capacity requirement.
- **Interregional planning**, coordination & visibility with neighboring jurisdictions.

Our work in Hawaii (see references in Appendix) demonstrates how island systems that are unable to regionalize can technically achieve similar levels of renewable penetration. However, such islands would have to rely on other forms of reliability enhancements in order to do so and these reliability enhancements would likely carry a higher cost versus regionalization.

6.1 California renewables expansion benefits from regionalization via the Western Energy Imbalance Market

In 2010, GE Energy and NREL identified the value of greater regionalization to support California's aggressive renewable penetration goals in our Western Wind and Solar Integration Study.[8] For example, Figure 5 shows the results of our analysis highlighting how greater interregional cooperation for 5 minute spinning reserves could save $2B.

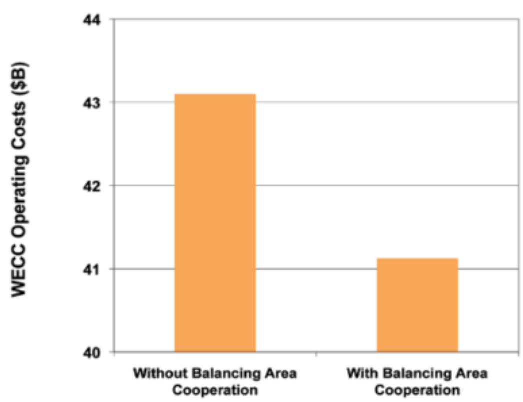


Figure 5 Results from 2010 GE-NREL WWSIS study illustrating the $2B in savings by holding spinning reserves as 5 large regions (right) versus many smaller zones (left).[8]

[8] NREL, "Western Wind and Solar Integration Study," http://www.nrel.gov/docs/fy10osti/47434.pdf http://www.nrel.gov/docs/fy10osti/47781.pdf

This work helped support the 2014 launch of the Western Energy Imbalance Market that is operating today and enables California to benefit from operational flexibility at ~30% variable renewable penetration.[9]

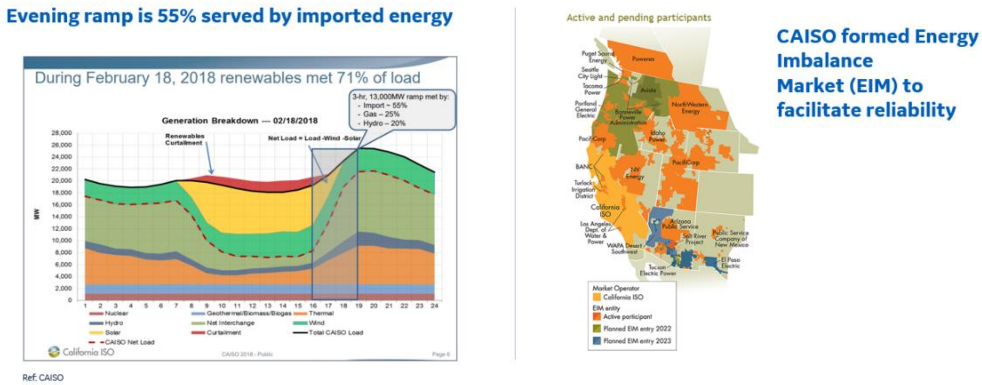
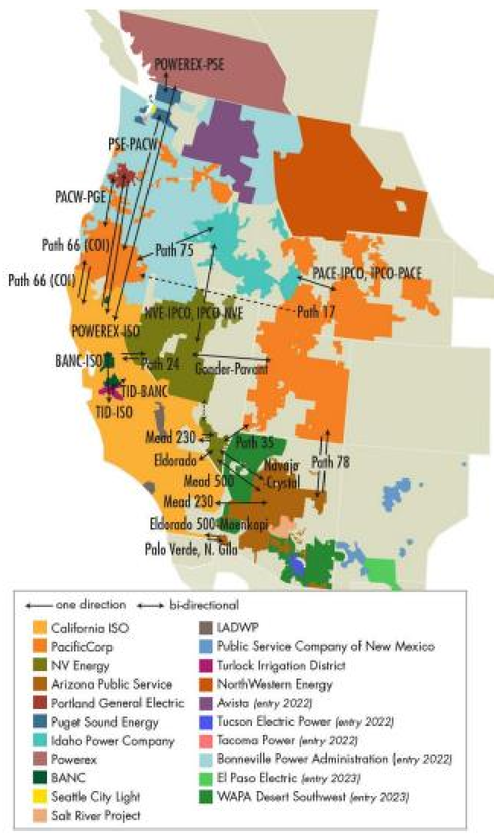


Figure 6 Data and map from CAISO illustrating how imports support the California "duck curve" or evening ramp in net load. These imports have been facilitated by the formation of the Western Energy Imbalance Market.



Path	Estimated Max Capacity (MW)
Path 24 (west to east)	100
Path 24 (east to west)	35-90
Eldorado	797
Path 35 (west to east)	580
Path 35 (east to west)	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 (ISO to PGE)	627
Path 66 (PGE to ISO)	296
Path 66 (ISO to PACW)	331
Path 66 (PACW to ISO)	432
Path 17	0-400[1] [2]
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 (PACE to APS)	625
Path 78 (APS to PACE)	660
Navajo-Crystal	522
Mead 500	349
Mead 230 (APS <–> ISO)	236
Mead 230 (ISO to NVE)	3,443
Mead 230 (NVE to ISO)	3,476
IPCO to PACW (Path 75)	1,500
PACW to IPCO (Path 75)	400-510
PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <–> PSE	150
Powerex <–> ISO	150
BANC <–> ISO	2,000-4,000
TID to ISO	1,400
TID to BANC	650

[1] Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity.

[2] When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17, and not double counted.

Current as of October 2021

Figure 7 Interregional transfer capability utilized by the Western Energy Imbalance market.[10]

[9] https://www.westerneim.com/

[10] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

The Western EIM would not be possible without the physical transmission infrastructure that enables power flows across the Western US. Figure 7 summarizes the inter-regional transmission capability across the EIM footprint. **For example, the largest inter-regional capacity outside California is ~3400 MW between CAISO and NV Energy.**

Benefits

$1.72 billion in gross benefits since Nov 2014 *(as of 10/28/2021)*

(millions $)

EIM PARTICIPANTS	2014-2019	2020	2021			TOTAL
			Q1	Q2	Q3	
Arizona Public Service Entered 10/2016	$140.32	$48.96	$15.01	$9.25	$24.58	$238.12
BANC Entered 04/2019	$15.86	$30.36	$7.53	$18.12	$72.52	$144.39
California ISO Entered 11/2014	$191.88	$62.04	$8.91	$27.58	$54.01	$344.42
Idaho Power Company Entered 04/2018	$55.11	$26.30	$12.54	$15.23	$17.76	$126.94
LADWP Entered 04/2021				$8.54	$23.57	$32.11
NV Energy Entered 12/2015	$89.03	$24.62	$14.14	$6.20	$18.04	$152.03
NorthWestern Energy Entered 06/2021				$1.06	$5.16	$6.22
PacifiCorp Entered 11/2014	$235.29	$40.63	$20.48	$15.05	$40.12	$351.57
Portland General Electric Entered 10/2017	$73.27	$31.76	$8.80	$7.45	$7.12	$128.40
PNM Entered 04/2021				$2.32	$6.77	$9.09
Powerex Entered 04/2018	$19.78	$4.03	$1.17	$1.01	$0.92	$26.91
Puget Sound Energy Entered 10/2016	$41.25	$13.68	$4.31	$4.16	$6.78	$70.18
Salt River Project Entered 04/2020		$36.06	$5.52	$12.61	$17.78	$71.97
Seattle City Light Entered 04/2020		$6.64	$2.60	$2.75	$3.92	$15.91
TID Entered 04/2021				$1.37	$2.13	$3.50
TOTAL	$861.79	$325.08	$101.01	$132.70	$301.18	**$1,721.76**

Figure 8 Summary of economic benefits from the Western EIM by participant.[11]

While the EIM is aimed at enhancing operational flexibility, it's a great example of how regionalization is an economically efficient form of flexibility—having realized almost $2B in gross benefits since 2014 as summarized in Figure 8. By leaning on a wider footprint across balancing areas to support grid services, this can substantially lower the operational and integration cost. Strengthening interregional ties and deploying capabilities across them via markets and requirements was shown in the above-mentioned GE and NREL studies.

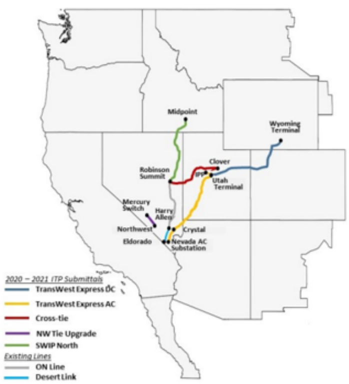
As the same time, **CAISO has been engaged in an interregional transmission planning process since 2015 to support all three areas of reliability.**[12] The CAISO and regional entities throughout the western interconnection collaborate during their transmission planning processes to ensure regional transmission stability and efficiency. These coordination efforts inform each entity's transmission plans. The interregional planning regions are WestConnect, NorthernGrid and California ISO.

[11] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

[12] http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

The CAISO interregional transmission planning process (ITP) is performed in a 2 year planning cycle covering all three areas of reliability that we previously outlined:

1) ***Adequacy***: extreme weather assessment (e.g. wildfires), localized capacity evaluation (e.g. storage, gas alternatives)
2) ***Operations***: flexible capacity deliverability
3) ***Stability***: frequency response assessment (e.g. potential tripping effects in case of Palo Verde nuclear outage)



Project Name	Sgmts	Company	CEII or Confidential Data Submitted	Project Submitted to	Relevant Planning Regions	Cost Allocation Requested From	Termination From	Termination to	In Service Date
Cross-Tie Transmission Project		TransCanyon, LLC	Yes	CAISO, NTTG, NG, WC	NG and WC	CAISO, NTTG and WC	Clover, UT (PacifiCorp)	Robinson Summit, NV (NV Energy)	2024
Northwest Tie Upgrade		GridLiance West	No	CAISO, WC	CAISO and WC	CAISO, WC	Innovation (VEA, GLW, CAISO)	Northwest, NV (NVE)	2024
SWIP-North`		Great Basin Transmission LLC	Yes	CAISO, NTTG and WC	NG, WC and CAISO	CAISO, NTTG and WC	Midpoint. ID (IPCO, PAC)	Robinson Summit, NV (NV Energy)	2023
TWE WY-IPP DC Project[149]	1	TransWest Express, LLC	No	CAISO and NTTG	Not an ITP	CAISO	Sinclair, WY (PAC)	Delta, UT (PAC)	2025
TWE WY-IPP DC + IPP-Crystal 500 kV AC Project	1+2	TransWest Express, LLC	No	CAISO and NTTG	NG + (WC)	CAISO	Sinclair, WY (PAC)	No. Vegas (NV Energy)	2025
TWE WY-IPP DC + Crystal - Eldorado 500 kV AC Project	1+3	TransWest Express, LLC	No	CAISO and NTTG	NA – segments not contiguous	CAISO			2025

Figure 9 Interregional transmission projects submitted to CAISO for their 2020-2021 interregional planning cycle.[13]

In Figure 9 we show **six interregional transmission projects that have been submitted to CAISO** as part of this holistic interregional planning process.

6.2 Southwest Power Pool (SPP) renewable penetration benefits from regionalization via continued expansion

The high levels of renewable penetration we observe from SPP has been enabled by their vast geographic footprint along with their continued interregional expansion. Though Table 3 seems to suggest that they do not have heavily reliance on interregional resources today, SPP has been steadily expanding their footprint since 2015 in order to incorporate the value of regionalization into their operations.

[13] http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf

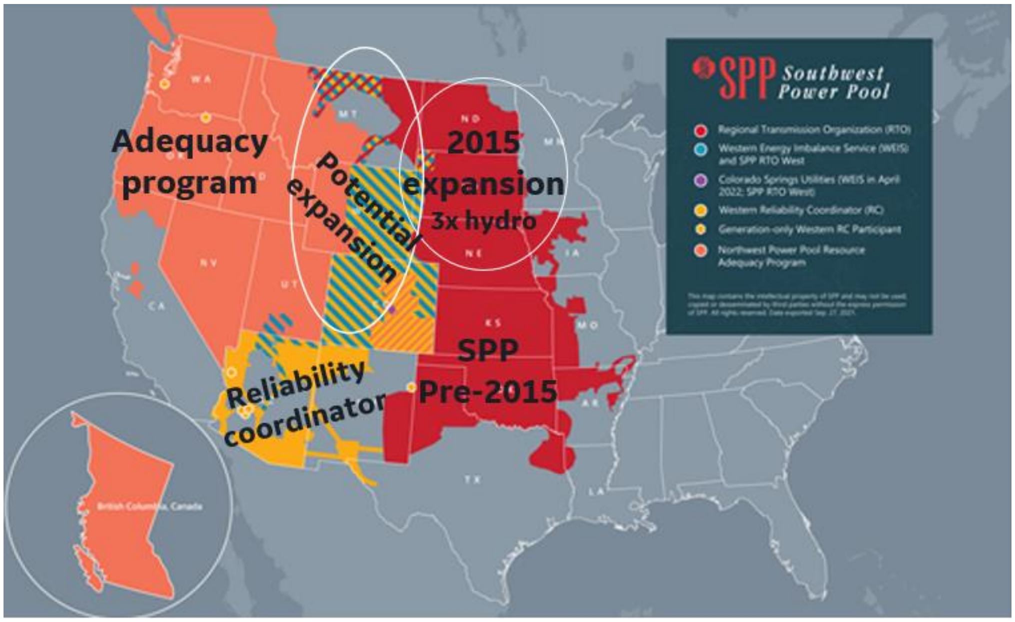


Figure 10   Southwest Power Pool map showing the current range of operational areas and services[14].

SPP is very transparent regarding the value that regionalization has brought to members in its territory. In its "2020 Member Value Statement," [14] SPP shares that it has provided $2B in savings to its members in 2020. **Of this $2B in member savings, transmission was the largest component of value at ~$770M. According to SPP, every dollar SPP directs toward transmission expansion returns at least $3.50 in benefits** via:

- Higher reliability and deliverability
- Lower production costs
- Creating new revenue streams
- Reduced on-peak generation costs
- Reduced planning reserve margins
- Reduced resource adequacy requirements
- Improved siting of new generation
- Accelerated renewable integration

As SPP expands its services across the Northwest Power Pool, the cost-benefits of greater regional coordination are leading the efforts.[15] These benefits are projected to produce ~$50M per year in savings and span all three forms of reliability that we have previously outlined as follows:

- Imbalance services
- Reliability coordination
- Planning coordination
- Unscheduled flow mitigation

[14] SPP.org

[15] https://spp.org/western-services/

6.3 Danish renewable penetration benefits from regionalization via ENTSO-E

The high levels of Danish renewable penetration also heavily rely on regionalization for all three types of reliability: 1) adequacy; 2) operational; and 3) stability via the ENTSO-E (European Network of Transmission System Operators for Electricity).

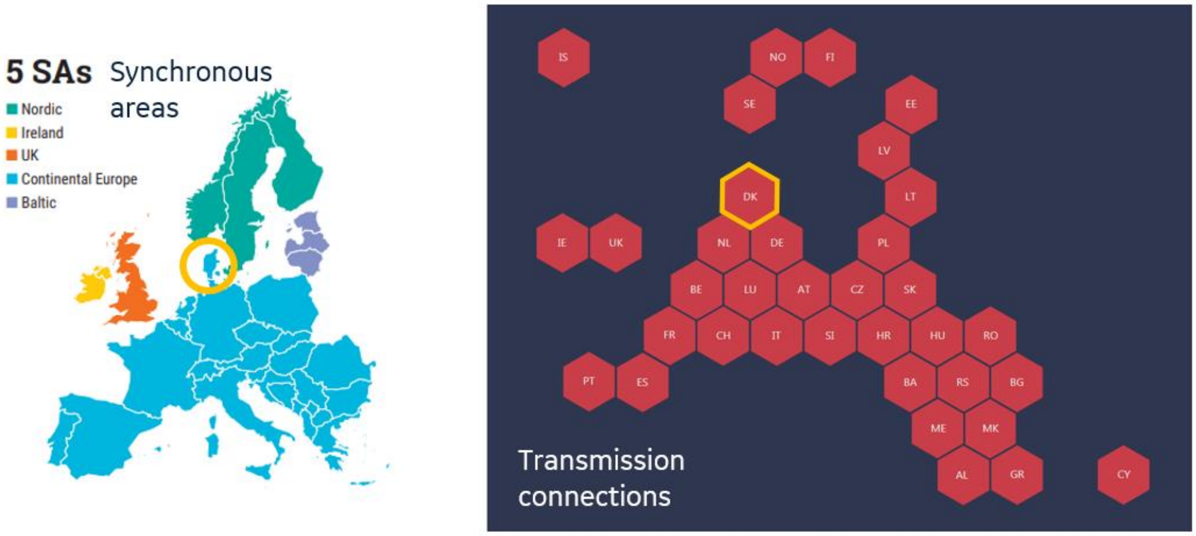


Figure 11 ENTSO-E maps showing the five synchronous areas and inter-country transmission coordination.[16]

The Continental European grid with coordination through ENTSO-E allows Denmark to rely on its neighbors for grid strength, balancing, and sharing of resources to manage uncertainty. Coordination of transmission interconnection and operation is done at the EU Commission level via ENTSO-E, and allows Denmark to achieve instantaneous variable inverter-based resource (IBR) penetrations well above 100%. Modeling and grid planning are coordinated across the EU regions by ENTSOE to maintain sufficient adequacy, resiliency and stability.[12]

The strength of this heavily regional approach is validated by the fact that the January 2021 "European Grid Separation" event did not result in significant blackouts.[17]

7 The rest of the US will need to reflect today's best practices

When we look at where the United States is headed with respect to variable renewables penetration, we see that much of the US in 2035 will look like California, the Great Plains region, and Denmark today.

[16] https://www.entsoe.eu/

[17] https://www.entsoe.eu/news/2021/07/15/final-report-on-the-separation-of-the-continental-europe-power-system-on-8-january-2021/

Potential customer benefit of interregional transmission

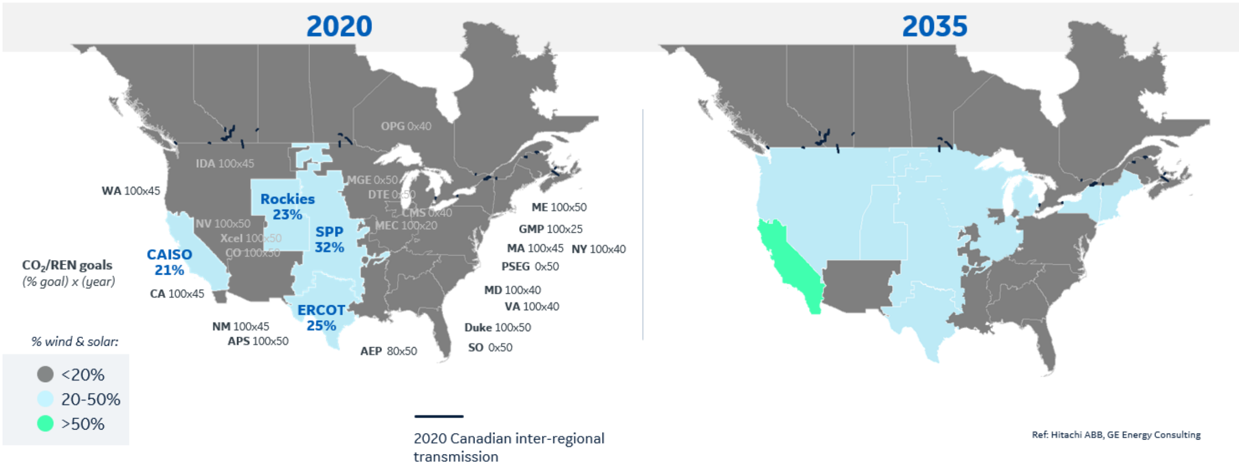


Figure 12 GE Energy Consulting forecast of regional variable renewables penetration in 2035 versus 2020.

In Figure 12, we show GE Energy Consulting's forecast of variable renewables penetration in 2035 versus 2020. Our forecasts are based on utility/grid operator load growth forecasts along with decarbonization policies spanning multiple layers of government. While much of the country is below 20% variable renewables today, **by 2035, much of the country will be between 20-50% VRE penetration**. This means that by 2035:

1. From an *adequacy* perspective: There will be hours where variable renewables within certain regions are close to zero coupled with the uncertainty of extreme weather. **The 2035 US will therefore benefit from the higher *diversity* enabled by regionalization.**
2. From an *operational* perspective: There will be hours where variable renewables approach or exceed 100% within certain regions along with intervals of high ramping. **The 2035 US will therefore benefit from higher *flexibility* enabled by regionalization.**
3. From a *stability* perspective: Each of the three US interconnections will be highly dependent on inverter-based resources to maintain voltage and frequency. **The 2035 US will therefore benefit from the higher *grid strength* enabled by regionalization.**

Given what we have shared regarding the potential reliability challenges, and potential mitigations for CAISO and Denmark today, we believe the rest of the US will need to increasingly leverage the reliability enhancement options we summarized in Table 2. Given the continental nature of the US systems along with our prior study work assessing the cost-benefit tradeoffs of the various solutions, **we contend that greater regionalization can be the most cost-effective mechanism for achieving resilient adequacy, flexibility, and stability in the 2035 US.**

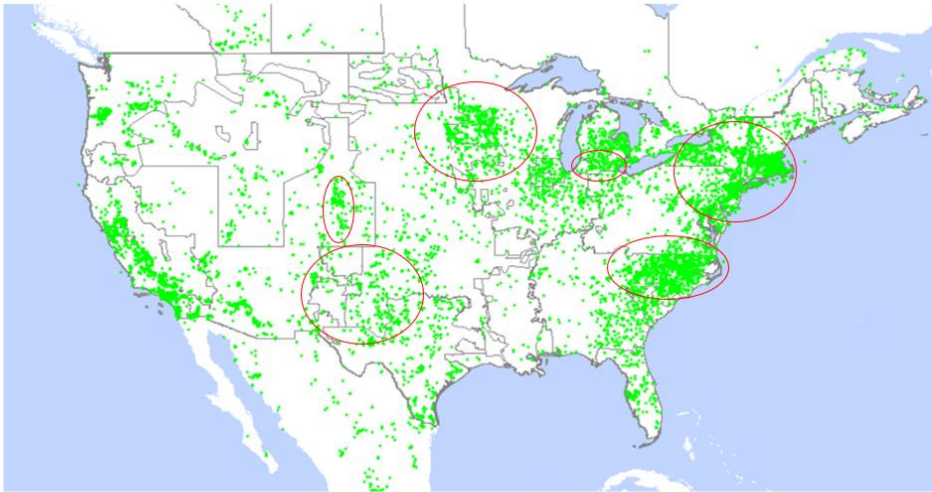


Figure 13 Regional map of the US showing siting of operating and planned wind and solar projects as of 2020. The circled areas highlight areas of high wind and solar siting along interregional interfaces. These are areas that could potentially benefits from greater interregional transfer capacity.[18]

At the same time, even looking at a current map of the US showing siting of wind and solar projects both in operation and under development, show how **projects are often located at the interfaces between two regions.** From our experiences interconnecting many of these projects, we observe that control stability of IBRs continues to be more challenging at regional interfaces. **Strengthening interregional transmission connections across seams where there are growing high-penetration pockets of IBRs can help ensure sufficient power flow during extreme weather events and, in certain cases, assist in resolving weak grid stability constraints** (e.g. between MISO and SPP). In addition, interregional sharing of services around balancing, frequency and voltage support, and managing variability and uncertainty of VER across stronger interregional ties has great benefit to reduce overall integration costs. Interregional assessment and interconnection is therefore also becoming more important as IBR penetration levels grow.

[18] ABB Hitachi

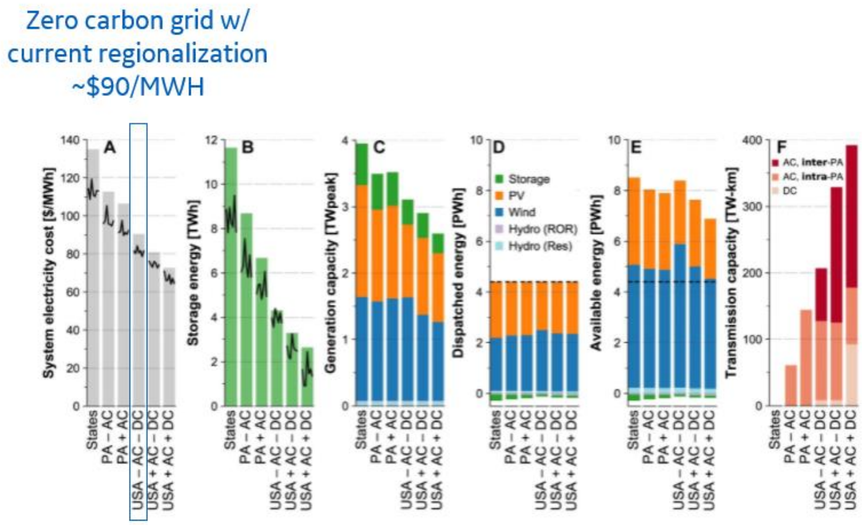


Figure 14 MIT study highlighting the economic benefit of higher regionalization to a zero-carbon grid.[19]

A recent MIT study also pointed to the benefits of higher transmission build-out to a future decarbonized US grid. In Figure 14 we show a summary of their analysis showing how a decarbonized US with higher transmission-enabled regionalization could lower average energy costs by ~$20/MWH (left graph). The areas of value are shown in the graphs to the right:

1. Lower long term storage requirement
2. Lower generation capacity requirement

One important implication of this work is that the economic benefit of greater transmission is higher than the economic benefit of greater storage in a zero-carbon electric mix.

8 Suggesting a requirement for incremental interregional transmission

For the future United States, **how can a minimum interregional transmission requirement be assessed** to reliably and cost-effectively support the anticipated renewables build-out while planning for new extreme weather events? GE team proposes the following *potential* approach to assess the operational, stability and adequacy benefits of increased transmission interconnection. This approach focuses on the technical benefits and should be used as part of a fuller analysis that considers the economics compared to alternatives.

[19] Brown and Botterud. The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity Grid. MIT. (Dec 2020)

8.1 Operational incremental interregional transmission requirement

In order to assess the operational benefits of increased interregional transmission capacity, we propose simulating the dispatch of the US system under the following two conditions:

1) *Condition 1:* **Unconstrained interregional imports/exports.** We suggest removing the MW limits associated with inter-pool transmission flows to determine the total power flow amounts between pools.

   Output: **Total transmission-unconstrained interregional power flow amounts between pools.**

2) *Condition 2:* **Constrained[20] interregional imports/exports**. We suggest simulating the same system after re-instating the existing/expected MW limits associated with the inter-pool transmission flows. This will allow the determination of the total power flow amounts between pools utilizing the existing/planned transmission system. We would expect renewables curtailment to be higher under this condition.

   Output: **Total transmission-constrained interregional power flow amounts between pools.**

Utilizing simulations under both the constrained and unconstrained EI conditions would allow us to calculate an “operational incremental interregional transmission requirement.” These requirements could be calculated on a pool-to-pool basis for each pool across the United States. GE MAPS is an example of a software tool that could be used for this assessment.

8.2 Adequacy incremental interregional transmission requirement

In order to determine the incremental interregional transmission requirement to support future resilience and renewables uncertainty needs. We propose using a similar approach as described in Section 8.1 with the **addition of a stochastic dimension to test for the incremental transmission need given renewables uncertainty, outages, and extreme weather.** These requirements will be calculated on a pool-to-pool basis for each pool across the United States.

Given that recent grid events have highlighted adequacy risks across every type of resource (e.g. frozen cooling water, gas supply outages, transmission outages, extreme temperatures), we suggest:

- **Broadening the potential sources of failure** (e.g. non-electric sources of failure such as gas supply outage)
- **Testing new weather extremes** (e.g. extreme temperatures)
- **Testing coincidence of failures** (e.g. extreme temperatures during gas supply failure, or cyber attacks across multiple resources simultaneously)

GE MARS would be an example software tool that could be used for this assessment.

[20] Note on Constrained and Unconstrained in this section pertains to deliverability of MW based on thermal ampacity of transmission lines. It does not include stability constraints at this stage. Stability would be assessed as part of 8.3 via screening techniques.

8.3 Stability incremental interregional transmission requirement

In order to determine the incremental interregional transmission requirement to support stability needs. We suggest the following steps:

Step 1: Use the dispatch simulation results (see Section 8.1) and transmission maps to downsselect interregional areas of high IBR penetration and series compensation.

Step 2: For each of these areas, we suggest running a production cost (e.g. GE MAPS), stability and short circuit simulations (e.g. in PSSE or GE PSLF) under the following two conditions:

> *Step 2.1--**Condition 1:*** Current system with current interregional ties and series compensation.
> *Step 2.2--**Condition 2:*** Add in incremental interregional transmission (MW) and bypass series compensation.

Step 3: Under these two conditions, we suggest testing the following on a pass/fail basis:

- ☐ **Weak grid & voltage stability**: Was the short circuit current ratio acceptable (e.g. SCR>3) in both cases?
- ☐ **Frequency stability**: Was the headroom on committed synchronous units acceptable?
- ☐ **Small signal stability**: Were there unwanted resonances?

Step 4: If any of the tests in Step 3 fail, repeat Step 2.2 with additional incremental transmission until all stability tests pass. The total additional transmission is the interregional requirement.

8.4 Total incremental interregional transmission requirement

We propose that a total incremental interregional transmission requirement would encompass the three reliability benefit components described above. It is important to acknowledge that the technical value of greater interregional transmission may stem from any or all of the three areas of reliability. **In our experience, typical studies focus on one of these three reliability areas while missing the others.** Individual pools across the US may find value from differing areas of reliability given their existing infrastructure combined with their projected expansion.

9 Conclusion: Coordinated interregional transmission is a proven enabler for resilient decarbonization

GE Energy Consulting forecasts a 2035 United States that will look similar to the California, Great Plains region and Denmark of 2020 with high penetrations of variable inverter-based renewables. The value of regionalization for increasing adequacy, operational reliability, and stability, that has been validated for SPP, California and Denmark, should be assessed for the broader US.

GE Energy Consulting has suggested a methodology to assess the incremental transmission requirement for a regionalized future US with higher renewables and extreme weather uncertainty. This incremental requirement would be based on a holistic assessment of three areas of reliability benefit:

1) *Operational:* Incremental interregional transmission can enable lower wind and solar curtailment which results in fuel cost savings.
2) *Adequacy:* Incremental interregional transmission can enable higher generation diversity in the face of uncertainties such as: generation, transmission or fuel outages or extreme weather events.
3) *Stability:* Incremental interregional transmission can enable greater system strength to avoid unintentional unit tripping due to fluctuations in voltage, frequency or unwanted oscillations.

Today, there are limited practices in place for each region to evaluate the consumer benefits of regionalization on their own. National-level guidance would help chart the path towards realizing the benefits of greater regionalization.

APPENDIX: GE ENERGY CONSULTING RENEWABLE INTEGRATION STUDY REFERENCES

Most of GE Energy Consulting's wind and solar integration study work is publicly available at the following links:

- Australian Energy Market Operator, "Technology Capabilities for Fast Frequency Response," https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf
- Barbados Light & Power Company , "Barbados Wind and Solar Integration Study," http://www.blpc.com.bb/images/watts-new/Barbados%20Wind%20and%20Solar%20Integration%20Study%20-%20Exec%20Summary.pdf
- California Energy Commission's Intermittency Analysis Project Study "Appendix B - Impact of Intermittent Generation on Operation of California Power Grid," http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081-APB.PDF
- California ISO, "Frequency Response Study," Oct, 2011 http://www.caiso.com/Documents/Report-FrequencyResponseStudy.pdf
- CanWEA "Pan-Canadian Wind Integration Study," (PCWIS), 2016 https://canwea.ca/wind-integration-study/
- Electrical Reliability Council of Texas, "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements," http://www.ercot.com/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip (Note, this is a zip file that automatically downloads.)
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- NREL "Eastern Frequency Response Study," June 2013, https://www.elp.com/articles/print/volume-93/issue-1/sections/t-d-operations/eastern-interconnection-offers-positive-outlook-for-wind-generation-with-frequency-responsive-plant-controls.html
- NREL, "Western Wind and Solar Integration Study,"
- http://www.nrel.gov/docs/fy10osti/47434.pdf
- http://www.nrel.gov/docs/fy10osti/47781.pdf
- PJM Interconnection, LLC, "PJM Renewable Integration Study," http://www.pjm.com/~/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx

Attachment 5

A Roadmap to Improved Interregional Transmission Planning
Brattle Group (Nov. 30, 2021)

A Roadmap to Improved Interregional Transmission Planning

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November 30, 2021

Brattle

NOTICE

This report was prepared with funding from the Natural Resource Defense Council (NRDC).

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- Pfeifenberger *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, The Brattle Group and Grid Strategies, October 2021.
- Pfeifenberger, Transmission Planning and Benefit-Cost Analyses, April 29, 2021.
- Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, prepared for ACORE, July 2021.
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- Pfeifenberger, Ruiz, Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, published by Boston University's Institute for Sustainable Energy, September 1, 2020.
- Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future*, prepared for WIRES May 2016.
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This report reflects the analyses and opinions of the authors and not necessarily those of The Brattle Group's clients or other consultants.

CONTENTS

Executive Summary

Most stakeholders in the electric power industry today agree that expanding interregional transmission capability can deliver cost savings to customers, particularly as the grid transitions to cleaner generation resources. In the recent Federal Energy Regulatory Commission (FERC) Advance Notice of Proposed Rulemaking (ANOPR),[1] at least 32 comments referenced interregional transmission and most of them favored improving interregional planning processes.

Numerous studies have confirmed the significant benefits of expanding interregional transmission in North America, demonstrating that building new interregional transmission projects can lower overall costs, help diversify and integrate renewable resources more cost effectively, and reduce the risk of high-cost outcomes and power outages during extreme weather events. Moreover, interregional transmission benefits range far beyond just delivering renewable resources to load zones and include reliability, resiliency, market efficiency, and resource adequacy benefits. This means there are often substantial costs and risks to *not* expanding interregional transmission. Several recent events, including the 2021 winter storm Uri, emphasize the very large potential (but thus far unrealized) reliability benefits and cost savings that interregional transmission can provide. These events show that the lack of sufficient interregional transmission imposes great risks and can lead to tremendously high costs.

In spite of this near-consensus that the benefits and value of expanding interregional transmission capabilities often exceed its costs (thereby reducing overall system costs), virtually no major interregional transmission projects have been built in the U.S. over the last decades. To understand why cost-effective interregional transmission projects do not get built, we surveyed stakeholders from 18 different organizations across the industry, including RTOs, state and federal policymakers and regulators, large customers, industry and environmental groups, and utilities. These stakeholder interviews identified numerous barriers to interregional transmission planning and project development that fall into three interrelated categories as shown in Table ES-1: (A) Priorities, Alignment, and Understanding, (B) Planning Processes and Analytics, and (C) Regulatory Constraints.

1 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024 (2021).

TABLE ES-1: SUMMARY OF BARRIERS TO INTERREGIONAL TRANSMISSION PLANNING AND DEVELOPMENT

A. Priorities, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policymakers to prioritize interregional planning 2. Limited trust amongst states, RTOs, utilities, & customers 3. Limited understanding of transmission issues, benefits, & proposed solutions 4. Misaligned interests of RTOs, TOs, generators, & policymakers 5. States prioritize local interests, such as development of in-state renewables
B. Planning Process and Analytics	6. Benefit analyses are too narrow and often not consistent between regions 7. Lack of proactive planning for a full range of future scenarios 8. Sequencing of local, regional, and interregional planning 9. Cost allocation (too contentious or overly formulaic)
C. Regulatory Constraints	10. Overly-prescriptive tariffs and joint operating agreements 11. State need certification, permitting, and siting

While we provide preliminary recommendations to address the barriers in categories A and C, this report focuses primarily on the second set of barriers and develops a "roadmap" of recommendations to improve interregional planning processes and analytics. Improved processes and analytics are prerequisites for addressing the other barriers. However, recognizing that it will require federal and state policy makers and planning authorities to prioritize interregional issues, we also offer our initial thoughts on what the role of these authorities should be in addressing at least some of the identified barriers, implementing the recommended planning process improvements, and addressing the associated regulatory constraints.

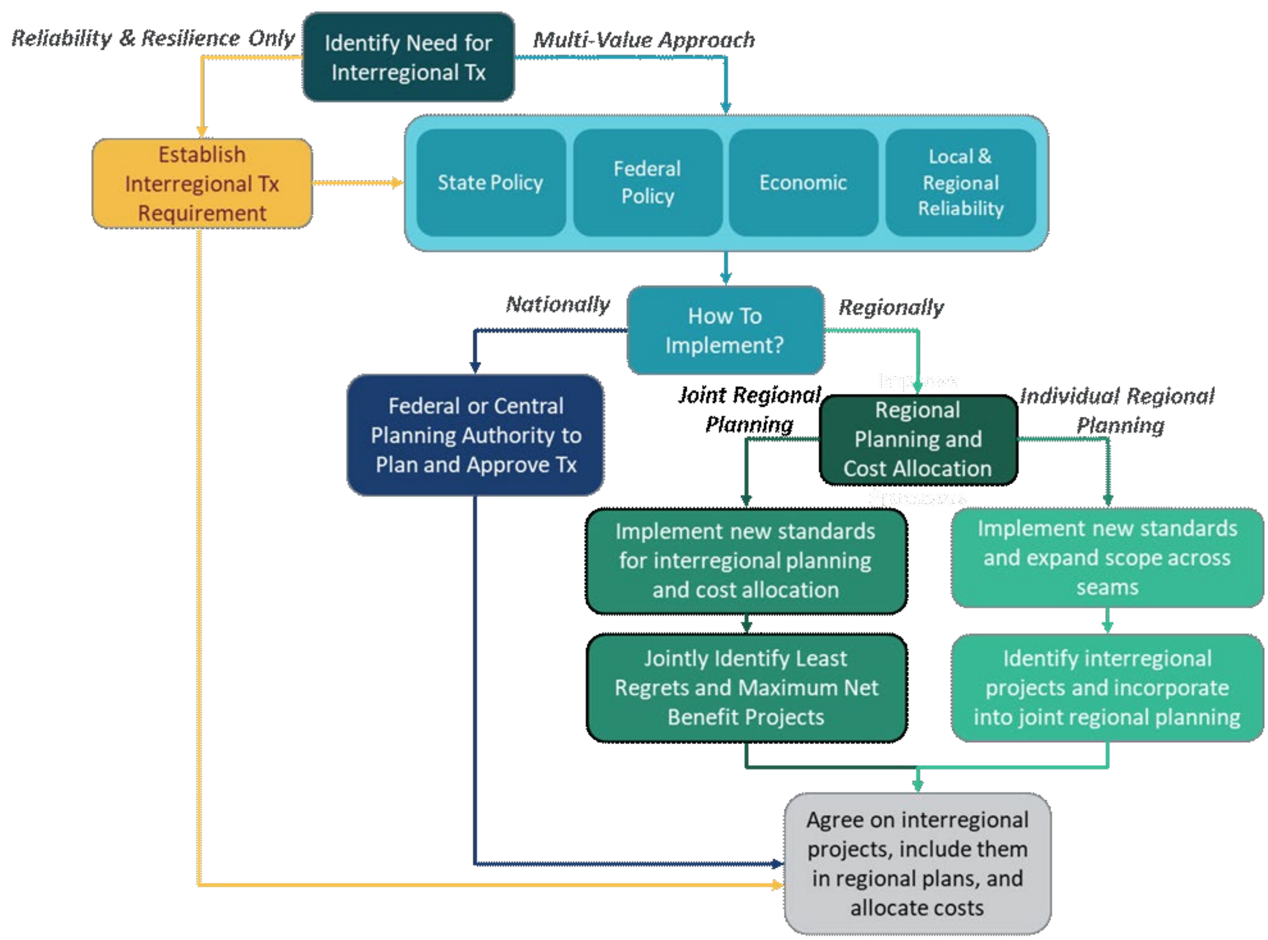
Addressing planning-process-related barriers to interregional transmission starts with improving the **determination of interregional transmission needs** and the sequencing of how those needs are addressed through transmission solutions. Currently, interregional transmission needs are determined only through regions' joint interregional planning processes that often are too narrowly defined to be able to identify interregional transmission needs and cost-effective solutions to these needs. Meanwhile, compartmentalized generator interconnection and local and regional reliability planning processes yield mostly incremental solutions to individual (and often near-term) needs that result in inefficient outcomes with higher system-wide costs. Not only has this process resulted in piecemeal upgrades primarily at the local and regional level (and often are solely reliability-driven without considering other needs), but the approved projects also pre-empt more cost effective regional and interregional transmission investment that could proactively and simultaneously address a broader set of future reliability, economic, and public policy needs.

We propose minimum standards to enhance the joint interregional planning processes and discuss three additional interregional planning pathways to more proactively and effectively determine the need for interregional transmission and solutions that can reduce system-wide costs. The combination of these four planning pathways will be more effective in identifying interregional needs and cost-effective interregional projects.

As illustrated in Figure ES-1 below, the four parallel pathways to determining and addressing interregional transmission needs are:

- Develop new reliability and resilience standards that would establish minimum interregional transfer capabilities
- Create a new federal or other central planning authority that would identify economic and public policy needs, including those driven by new state or federal policies
- Enhance the current joint interregional planning processes to take a broader view of interregional project needs and benefits
- Improve individual regional planning processes to prioritize the identification of interregional projects that could more cost-effectively and proactively solve regional needs (including generation interconnection needs) than available regional solutions and specify the process for proposing such solutions to the neighboring region

FIGURE ES-1: PARALLEL PATHWAYS TO ESTABLISHING THE NEED FOR INTERREGIONAL TRANSMISSION



We further address the narrow and inconsistent **benefit analyses** of the current interregional planning processes and develop standards based on proven practices to improve benefit analyses for interregional projects. The analyses used in transmission planning to measure the economic benefits of new projects today rely primarily on narrowly-applied production cost simulations to determine whether the cost savings offered by a transmission project exceed the project's costs. Other transmission-related economic benefits often are either not considered by the regional planning authority or not quantified because they lack the metrics and tools to estimate those benefits. Interregional transmission planning is especially challenging given the tendency of joint planning efforts to evaluate interregional projects based only on the smaller subset of benefits that are common to the planning processes of each of the respective regions involved. Yet, a complete assessment of the wide range of benefits provided by interregional projects is essential to both cost allocation and state permitting.

Lastly, we discuss the contentious and overly formulaic **cost allocation** processes that often exist. A successful approach to cost allocation will need to be sufficiently flexible to accommodate projects that address different types of interregional needs (*e.g.*, reliability, economic, and public policy projects) across different types of neighboring regions and entities (*e.g.*, RTO and non-RTO regions, FERC-jurisdictional, and non-jurisdictional entities); but they will also need to be specific enough to be actionable without being overly restrictive and formulaic. To achieve this balance, cost allocation agreements should include guidelines or illustrations of how benefit metrics would be applied. For example, the cost allocation guidelines might specify that the costs of an interregional transmission project should be allocated based on the share of monetized benefits, *i.e.*, in proportion to the present value of project benefits received by each region. Alternatively, if the regions agree, the guidelines could allow for the cost allocation for some interregional projects to be based on more qualitative, non-monetized benefits and cost causation ratios.

Building on industry experience of the last decade and our October 2021 report,[2] we further offer the following proven principles and recommendations for effective transmission planning processes as the starting point for better regional and improved interregional planning:

1. **Proactively plan for future generation and load** by incorporating realistic long-term projections of the anticipated generation mix, public policy mandates, load levels, and load profiles; integrate generation interconnection and local reliability planning processes into broader regional and interregional transmission planning to ensure the most cost-effective solutions can identified and not be pre-empted by less-efficient incremental solutions;
2. **Approach every transmission project as a multi-value project**, able to address multiple drivers and multiple needs, which may differ across the regions, and account for the full range of transmission

[2] Pfeifenberger *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, The Brattle Group and Grid Strategies, October 2021.

projects' benefits to comprehensively identify investments that can more cost-effectively address all categories of needs and benefits;

3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible (but uncertain) long-term futures as well as real-world system conditions, including challenging and extreme events; employ "least regrets" planning methodology to reduce the risks of an uncertain future and avoid under- or over-building transmission;
4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach; in particular, cost allocation should be based on the broad range of transmission-related benefits and, where possible for the entire portfolio of projects rather than individual projects, to take advantage of more stable and wide-spread benefits associated with recognizing multiple transmission-related values for entire portfolios of projects; and
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

However, as our stakeholder survey indicates, **interregional transmission planning and cost allocation creates unique challenges that go beyond the five principles mentioned above**. These additional challenges are addressed through proposed specific standards and principles for interregional needs determination, benefits quantification, and cost allocation developed as discussed in Sections II, IV and V of this roadmap report. We conclude the discussion of these interregional transmission planning topics—need determination, benefits quantification, and cost allocation—with recommended "key action items" for five major stakeholders: FERC, federal policy makers, state policymakers and regulators, regional planning authorities, and transmission owners.

I. Benefits of and Barriers to Interregional Transmission

Interregional transmission projects can provide significant cost savings and reliability benefits for customers and ensure the lowest cost outcomes as the grid transitions to clean resources. Numerous studies have shown that interregional transmission reduces costs, lowers electricity costs to customers, and reduces the risk of high-cost outcomes and power outages during extreme weather events and challenging market conditions (see Table 1 and Appendix A). While many of the national studies simulate various clean-energy futures, the benefits of interregional transmission go beyond transporting clean energy to load. Benefits also include resource and load diversification, increased system reliability and resilience, and wholesale power market benefits.

Table 1 summarizes a select group of recent studies that have analyzed the benefits of interregional transmission. For example, one such study found that an additional 1,000 MW of transmission capacity into Texas during winter storm Uri would have fully paid for itself over the course of the four-day event. The same study found that 1,000 MW of additional transmission capacity between MISO and PJM would have earned $100 million during the same short period of time.

Despite the net benefits of expanded interregional transmission estimated in these studies, they have failed to yield interregional transmission projects.[3] However, any beneficial expansion of interregional transmission capabilities identified in these national studies would also have to be confirmed as a need (that requires addressing) through the transmission planning processes of the respective regional planning authorities, which include the ISOs and RTOs, local transmission owners, as well as the various states' transmission siting and permitting agencies.

[3] These studies have not been successful in motivating improved interregional planning or actual transmission project developments because (1) many studies tend to analyze aspirational clean energy targets (*e.g.*, 100% by 2050) not the actual policies for the next 10–15 years; (2) the studies do not produce specific transmission projects; (3) the studies fail to identify how benefits and costs are distributed across jurisdictions; (4) there has not been an analysis of the state-by-state economic impact and job creation from interregional transmission development; and (5) most studies do not propose solutions to address the barriers to planning processes and to the development of new interregional transmission projects.

TABLE 1. SUMMARY OF SELECT RECENT INTERREGIONAL TRANSMISSION STUDIES

Study	Region	Findings
Grid Strategies Transmission Resilience Study (2021)	Various	During 2021 winter storm Uri, a gigawatt of transmission between Texas and the Southeastern U.S. could have saved lives and nearly $1 billion
NREL North American Renewable Integration Study (2021)	U.S., Canada, Mexico	Increasing international electricity trade can provide $10–$30 billion in net benefits Interregional transmission expansion achieves up to $180 billion in net benefits
MIT Value of Interregional Coordination (2021)	U.S. Nation-Wide	National coordination of transmission and clean-energy requirements reduces the cost of decarbonizing by almost 50% compared to no coordination between states The lowest-cost scenario builds almost 400 TW-km of transmission; including roughly 100 TW-km of DC capacity between the interconnections and over 200 TW-km of interregional AC capacity No individual state is better off implementing decarbonization alone compared to national coordination of generation and transmission investment Low storage and solar costs still result in significant cost-effective interregional transmission
Princeton Net Zero America Study (2021)	Nation-Wide	Achieving net-zero emissions by 2050 requires 700–1,400 TW-km of new transmission (two to five times the existing amount) Investment in transmission needed ranges $2–$4 trillion dollars by 2050
U.C. Berkeley 90% by 2035 (2020)	National-Wide	The only national study that suggest relatively little interregional transmission would be needed to achieve 90% clean electricity. However, the study's simulation approach does not utilize more granular and well-established methods to properly value interregional transmission.
Vibrant Clean Energy Interconnection Study (2020)	Eastern Interconnection	40 to 90 TW-km of transmission is built by 2050 to meet climate goals Transmission development can create 1–2 million jobs in the coming decades, more than wind, storage, or distributed solar development Transmission reduces electricity bills by $60–$90 per MWh
NREL Seams Study (2020)	Eastern & Western Interconnections	Major new ties between interconnections saves $4.5–$29 billion over a 35 year period

In the recent Federal Energy Regulatory Commission (FERC) Advance Notice of Proposed Rulemaking (ANOPR),[4] at least 32 comments referenced interregional transmission and most favored improved interregional planning processes, which include the following examples:

- *American Electric Power Service Corp.*: "The Commission should address planning for high-voltage interregional transmission projects, establishing system needs and common assumptions, which may include minimum interregional transfer capability requirements and resource adequacy standards, to encourage interregional transmission development."
- *Arizona Corporation Commission*: "Requiring either a joint planning process or coordination among neighboring regions would be beneficial to the Western Interconnection."
- *Commonwealth of Massachusetts Department of Energy Resources*: "Planning fundamentals should be applied to the interregional planning processes to allow for the identification of interregional projects that maximize net benefits across service territories."
- *New Jersey Board of Public Utilities*: "Interregional planning, particularly across the PJM/New York seam, is effectively non-existent, constantly mired in litigation based on outdated Commission rules and cost allocation processes."

FERC Order 1000 encouraged the regional planning authorities to coordinate interregional transmission planning but did not mandate the development of interregional transmission plans. Today, a decade after FERC Order 1000 was enacted, interregional transmission planning processes remain largely ineffective[5]—without any major interregional transmission projects having been approved in the U.S. since Order 1000 was implemented.

To better understand the reasons that prevent the development of cost-effective interregional projects from being realized through existing planning processes, we surveyed stakeholders from 18 different organizations across the industry, including RTOs, state and federal policymakers and regulators, large customers, industry and environmental groups, and utilities. We asked the stakeholders to provide their views about the benefits of interregional projects, the existing barriers to interregional transmission planning, and the potential solutions for improving interregional planning.

The stakeholder interviews consistently identified numerous barriers to interregional transmission planning and project development that fall broadly into the three interrelated categories shown in Figure 1: (A) Priorities, Alignment, and Understanding, (B) Planning Processes and Analytics, and (C) Regulatory Constraints. Table 2 lists the specific barriers identified in each of these three categories and additional details on each are presented in Appendix A.

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4 Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024 (2021).

5 See Pfeifenberger, Chang, and Sheilendranath, Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, Prepared for WIRES, April 2015, p. 31 and Pfeifenberger, Transmission Planning and Benefit-Cost Analyses, Presented to FERC Staff, April 29, 2021, p. 3.

FIGURE 1: CATEGORIES OF BARRIERS TO INTERREGIONAL TRANSMISSION PLANNING AND DEVELOPMENT

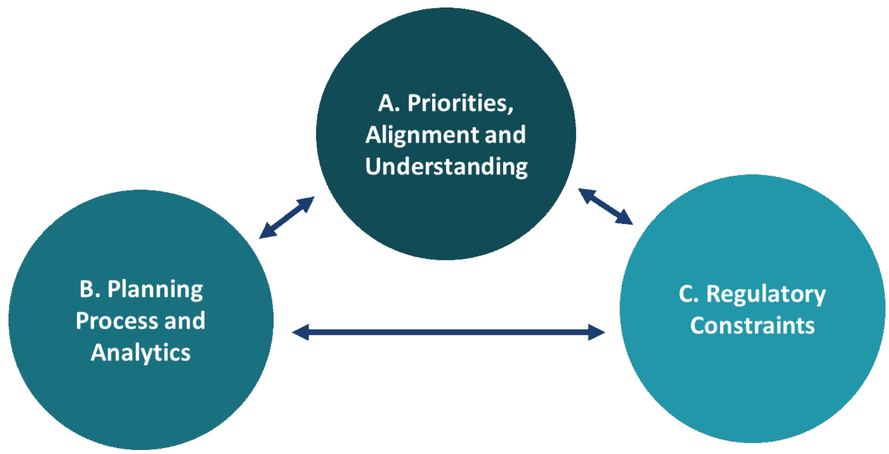

TABLE 2. SUMMARY OF BARRIERS TO INTERREGIONAL TRANSMISSION PLANNING AND DEVELOPMENT

A. Priorities, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policymakers to prioritize interregional planning 2. Limited trust amongst states, RTOs, utilities, & customers 3. Limited understanding of transmission issues, benefits, & proposed solutions 4. Misaligned interests of RTOs, TOs, generators, & policymakers 5. States prioritize local interests, such as development of in-state renewables
B. Planning Process and Analytics	6. Benefit analyses are too narrow and often not consistent between regions 7. Lack of proactive planning for a full range of future scenarios 8. Sequencing of local, regional, and interregional planning 9. Cost allocation (too contentious or overly formulaic)
C. Regulatory Constraints	10. Overly-prescriptive tariffs and joint operating agreements 11. State certification, permitting, and siting requirements

This whitepaper provides a roadmap for addressing primarily the second category of barriers: improving interregional planning processes and analytics. However, as these groups of barriers are interrelated and making progress in improving interregional transmission development will require addressing the barriers in each of the three categories, we offer some initial thoughts on what the role of different entities could be in addressing the identified barriers. Even if much-improved interregional planning and analytical processes were to be designed, those improvements are unlikely to be implemented and actionable without efforts to address the other barriers: understanding interregional transmission benefits, planning prioritization, stakeholder alignment, and regulatory constraints.

Implementing improved planning processes requires a better understanding of the holistic value of transmission, how to fairly allocate costs, and how to overcome institutional barriers by all parties involves in transmission planning. Because interregional transmission projects are a critical part of present and future reliability in the face of increasing extreme weather patterns and also offer considerable economies of scale that can obviate the need for more costly and siloed regional and local projects, regulatory frameworks also need to be modified to incent interregional projects and require joint interregional planning that analyzes and incorporates least regrets projects at the outset of the regional planning process. To promote alignment of interests between regions, promote better understanding of the value of such projects, fairly apportion costs, minimize the burdens on directly impacted communities and consumers, and garner necessary support for such efforts, the interregional planning process must include relevant federal, state, and local policymakers and a broad representation of stakeholder interests and perspectives. Similarly, addressing the identified regulatory constraints will require evaluating and updating RTO tariffs and agreements, federal regulatory policies, and transmission-related state policies to improve the determination of transmission needs, cost-allocation, and permitting processes.

The remainder of this roadmap report discusses the current interregional transmission planning processes and analytical approaches, ways to improve these processes, and supporting analytics to increase their ability to identify cost-effective interregional transmission projects, quantify their benefits, and allocate project costs so they are roughly commensurate with the identified benefits. Recognizing that it will require leadership from federal and state policymakers and planning organizations to prioritize interregional issues, we offer our initial thoughts on what the role of these entities may be in addressing the identified barriers, implementing the recommended planning process improvements, and addressing the associated regulatory constraints. The report concludes with a brief case study that demonstrates how several elements of the proposed roadmap were successfully applied by a group of transmission providers in Louisiana to identify and approve a cost-effective seams project that faced several of the interregional barriers identified by stakeholders.

II. Improving Interregional Planning Processes and Analytics

Interregional transmission planning processes and analytical frameworks currently used by neighboring regions are mostly ineffective in advancing interregional transmission development. The barriers to interregional planning have created a gap of transmission investments near and across market seams.

Our interviews with stakeholders explored existing barriers and the adverse impacts they have on the development of interregional transmission projects. For example, RTO planners noted that they have shifted transmission development away from their border, or “seam,” with neighboring regions to increase the benefits that accrue internally to their region and the likelihood of winning approval for such development. Stakeholders also noted that this shift has narrowed what is even considered for development and RTOs would identify very different regional system needs and transmission upgrades if they studied a broader regional footprint and measured benefits for areas beyond their own RTO's boundaries. These stakeholder observations highlight the importance of standardizing how transmission planners analyze system-wide needs, benefits, and costs under different future transmission scenarios to ensure that interregional transmission needs can be identified and economies of scale can be captured.

Consistent with the findings of our stakeholder interviews, addressing interregional transmission barriers requires:

- Updating the sequencing of planning processes for generation interconnection needs, local transmission needs, and regional reliability, economic, and public policy needs to enable establishing a need for interregional transmission projects
- Quantifying a broader set of transmission-related benefits in support of the project need
- Implementing more proactive planning for a full range of future scenarios to recognize and understand uncertainties in project needs and benefits to identify "least-regrets" projects
- Improving cost-allocation methods based on a better understanding of project benefits and uncertainties

Addressing these identified barriers requires improving every phase of interregional planning processes, as illustrated in Figure 2 below, starting with (1) initial needs assessment and project identification, (2) benefits analysis to determine an identified project's cost-effectiveness, and (3) project cost recovery based on the cost-allocation approach. Developing a more effective approach to interregional planning will consequently require addressing the barriers at each step of the planning process.

FIGURE 2: TRANSMISSION PLANNING PROCESS

A successful interregional planning process needs to:

- Allow for interregional system needs and solutions to be identified through a broader set of planning pathways
- Accommodate projects that simultaneously serve a range of system needs, often offering different types of benefits to each region
- Ensure that a broad set of benefits are considered in any benefit-cost analyses

- Analyze the benefits for scenarios that represent the likely range of plausible futures
- Define clear cost allocation methodologies that provide sufficient guidance for planners, regulators, and stakeholders and ensure that cost recovery for portfolios of approved projects is roughly commensurate with the projected benefits of the projects

Industry experience with proven planning and cost-allocation processes points to several core principles for improving transmission planning processes, including the processes utilized for interregional transmission planning. As we have pointed out in a recent report,[6] in order to be effective, transmission planning processes need to:

1. **Proactively plan for future generation and load** by incorporating realistic long-term projections of the anticipated generation mix, public policy mandates, load levels, and load profiles;[7] integrate generation interconnection and local reliability planning processes into broader regional and interregional transmission planning to ensure the most cost-effective solutions can be identified and not be pre-empted by less-efficient incremental solutions;
2. **Approach every transmission project as a multi-value project**, able to address multiple drivers and multiple needs, which may differ across the regions, and account for the full range of transmission projects' benefits to comprehensively identify investments that can more cost-effectively address all categories of needs and benefits;

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6 Pfeifenberger, *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, The Brattle Group and Grid Strategies, October 2021.

7 ANOPR comments have also addressed the appropriate timeframe over which transmission should be planned. There is almost universal agreement that the time horizon needs to be at least as long as the planning and development timeframes of major transmission projects, which often is a decade (if not more). However, while this approach would allow for the approval of projects that could realistically be completed before a specified need for the project first arises, such a "first-needs-based" approach will not be able to identify the most cost-effective solutions to address the multiple needs that a transmission project can address (and the benefits it would provide) over the course of its useful life.

For example, while a limited upgrade to a 230 kV transmission facility may address a specific reliability or generation-interconnection need within the next 10 years, a larger-scale 345 kV transmission investment may be more cost effective because it can address multiple needs that would likely arise in the decade(s) after the initial reliability need has to be addressed. For example, in addition to addressing the most pressing reliability need, the 345 kV upgrade may offer a lower-cost solution for longer-term generation interconnection needs, additionally reduce congestion and renewable curtailments over its lifespan, and address multiple reliability needs that would also have to be addressed in the future.

To capture these opportunities for addressing multiple future transmission needs at lower cost, projections for the anticipated generation mix, public policy mandates, load levels, and load profiles used in planning models should cover at least the time horizon of public policies (*e.g.*, the next 20 years for 2040 clean-energy mandates or the next 30 years for 2050 goals). Importantly, however, to reasonably compare a transmission investment's cost and benefits, the horizon of the benefit-cost analysis needs to cover (at least approximately) the cost-recovery lifespan of the transmission asset. If planning models only extend 20 years into the future, estimated benefits should be extrapolated beyond the 20 years (even if just indexed with inflation) to cover the remaining cost-recovery lifespan of the transmission asset. Otherwise the benefit-cost ratio of the investment will tend to be understated because benefits tend to grow over time (*e.g.*, with fuel costs and more stringent clean-energy and emissions standard) while project costs (*i.e.*, transmission revenue requirements) will tend to decline over time as the asset is depreciated.

For a discussion of using scenario-based planning to address long-term uncertainties, see pages 58-64 of Pfeifenberger, *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, The Brattle Group and Grid Strategies, October 2021.

3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that manages uncertainty by evaluating a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events and choosing "least regrets" options that prevent either over- or under-building transmission;
4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach; in particular, cost allocation methodologies need to account for the more stable and wide-spread benefits associated with recognizing multiple transmission-related values for entire portfolios of projects; and
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

As highlighted by our stakeholder interviews, however, the planning and cost allocation of interregional transmission creates unique challenges that go beyond the above principles. The following sections outline a roadmap for overcoming the key barriers to effective interregional transmission planning.

III. Identifying Interregional Transmission Needs

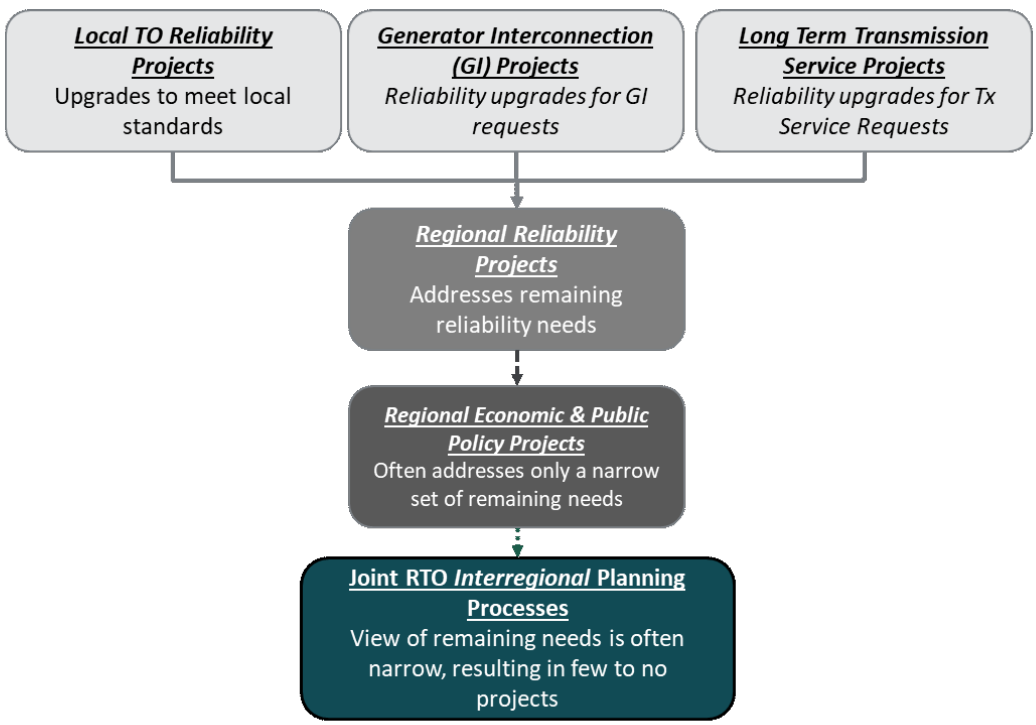
One of the main barriers hindering the ability to create an effective planning framework is the limited view currently taken to establish interregional project needs. In the transmission-planning context, "need" refers to projected problems for the transmission grid that can be addressed cost-effectively through a proposed solution. Defining a clear need that can be addressed through interregional transmission is essential for identifying cost-effective interregional projects during the planning process and for establishing that the projects are necessary and in the public interest during the RTO and state-level approval processes.

A. Limitations of Current Transmission Planning Processes

Currently, the needs for transmission projects are primarily placed into one of three separate buckets: (i) reliability and resilience driven needs, (ii) economic or market efficiency needs, and (iii) public policy needs. Reliability and resilience needs refer to system inadequacies that can trigger a violation of applicable reliability criteria if left unaddressed. Reliability needs, which represent the large majority of planned transmission projects in most regions, are identified as RTOs' plans for compliance with NERC and local reliability standards. Economic or market-efficiency needs generally refer to the cost savings that transmission upgrades can provide by reducing congestion, allowing the delivery of lower-cost power to load, and offering other grid- and generation-related benefits that reduce system-wide costs. Finally, public policy needs refer to the infrastructure required to cost-effectively meet the policy requirements of local, state, or federal governments—often clean-energy policies that require the integration of renewable energy resources.

The current transmission planning processes vary by region, but generally follow the process illustrated in Figure 3 below. The large majority of a region's transmission projects approved through the current planning processes are transmission upgrades to ensure compliance with the reliability needs set out by NERC and local utilities' reliability standards and are driven by: (1) local utility reliability planning, (2) generator interconnection requests, and (3) long-term transmission service requests—as shown by the first row of Figure 3.

FIGURE 3. PLANNING PROCESSES CURRENTLY USED IN RTOs TO IDENTIFY AND APPROVE TRANSMISSION PROJECTS



Once transmission projects based on these specific reliability needs are identified, most of the remaining projects are approved to address additional regional reliability needs. Together the local and regional reliability projects of the first and second row of Figure 3 account for the large majority (*I.e.*, more than 90%) of the approximately $25 billion/year of national transmission investments.[8] None of these

[8] *See* slide 1 of Pfeifenberger, Transmission—The Great Enabler: Recognizing Multiple Benefits in Transmission Planning, ESIG Fall Workshop, October 28, 2021.

reliability-driven projects involve any assessment of economic cost and benefits—which also means these investments add transmission costs but are not made with the objective to find the most cost-effective solutions from a total system-wide costs and electricity rates perspective. Only after these reliability needs are addressed are regional economic and public policy needs evaluated in most of the regional planning processes.

This sequencing leads to inefficient outcomes, as it results in incremental transmission upgrades that preempt larger regional or interregional projects, particularly those that could preemptively address the multiple needs more cost-effectively than the projects selected through the current (incremental, primarily reliability-focused) planning processes.

To the extent interregional planning efforts have been conducted under the current processes, it is generally based on a narrow view of economic benefits (often limited to traditional production cost savings) and without a consistent consideration of public policy needs. While there have been instances of successful planning of major regional transmission projections to address regional economic and public policy projects—such as CAISO's Location Constrained Resource Interconnection (LCRI) project, SPP's Integrated Transmission Planning (ITP) projects, MISO's portfolio of Multi Value Projects (MVP), ERCOT Competitive Renewable Energy Zones transmission, New York's Public Policy Transmission projects, and the New Jersey BPU's current efforts related to offshore wind integration[9]—these projects often account for only a small share of total transmission investments and do not address interregional needs. While existing planning regimes include some interregional coordination opportunities, they are generally ineffective and have produced only a few minor interregional transmission projects to date. This outcome in large part relates to the sequence of how the different needs are addressed—leaving few needs that could be addressed more cost-effectively through interregional transmission projects—and to an overly narrow assessment of interregional transmission needs and benefits.

In short, while there are many multi-regional and national studies that have identified many benefits from increasing interregional transmission capability as discussed above, the existing sequencing of transmission planning processes have not identified such interregional needs. As a result, very few interregional projects have ever been identified and approved under these processes.

Consistent with this general description of current transmission planning processes, our interviews with stakeholders have similarly identified (and confirmed) various reasons for why the current planning processes fail to identify transmission needs, particularly when focused on *interregional* needs:

- First, since each planning region has to ensure that its own system meets all applicable reliability standards, all of these reliability needs are addressed at the local and regional level. ***Almost by definition, there is no reliability need for interregional transmission projects left to address***.

[9] *See* Pfeifenberger, *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

- Second, many regional planning processes do not account for multiple drivers of the overall need for interregional transmission projects, which means that these ***processes are not set up to identify interregional transmission project solutions that can simultaneously and more cost-effectively address multiple regional and interregional needs***.
- Third, the scope of regional planning processes tends to be too narrowly focused in the consideration of transmission-related benefits and their geographic scope, typically quantifying only a subset of transmission-related economic and public policy benefits and considering only benefits that accrue to that particular region ***without considering the broader set of interregional benefits***. This means quantified benefits are frequently understated and even "regional" projects near the region's seams often fail to meet applicable benefit-cost thresholds for regional market-efficiency and public policy needs simply because the planning process ignores the benefits that accrue on the other side of the seam.
- Finally, ***local and regional reliability needs*** tend to be addressed quickly and projects are ***often approved before*** larger, proactive, and potentially ***more cost-effective interregional solutions can be considered*** and approved in a sufficiently timely manner.[10]

B. Multiple Pathways to Establishing Interregional Transmission Needs

Joint regional planning processes by neighboring regions currently are the primary pathway to identify interregional transmission needs and determine the benefits of candidate interregional transmission projects that could address these needs. Based on stakeholder input and our own experience with interregional transmission processes, we recommend reforms to joint interregional planning processes and identify additional pathways that could be implemented in parallel to establish the need for interregional transmission projects.

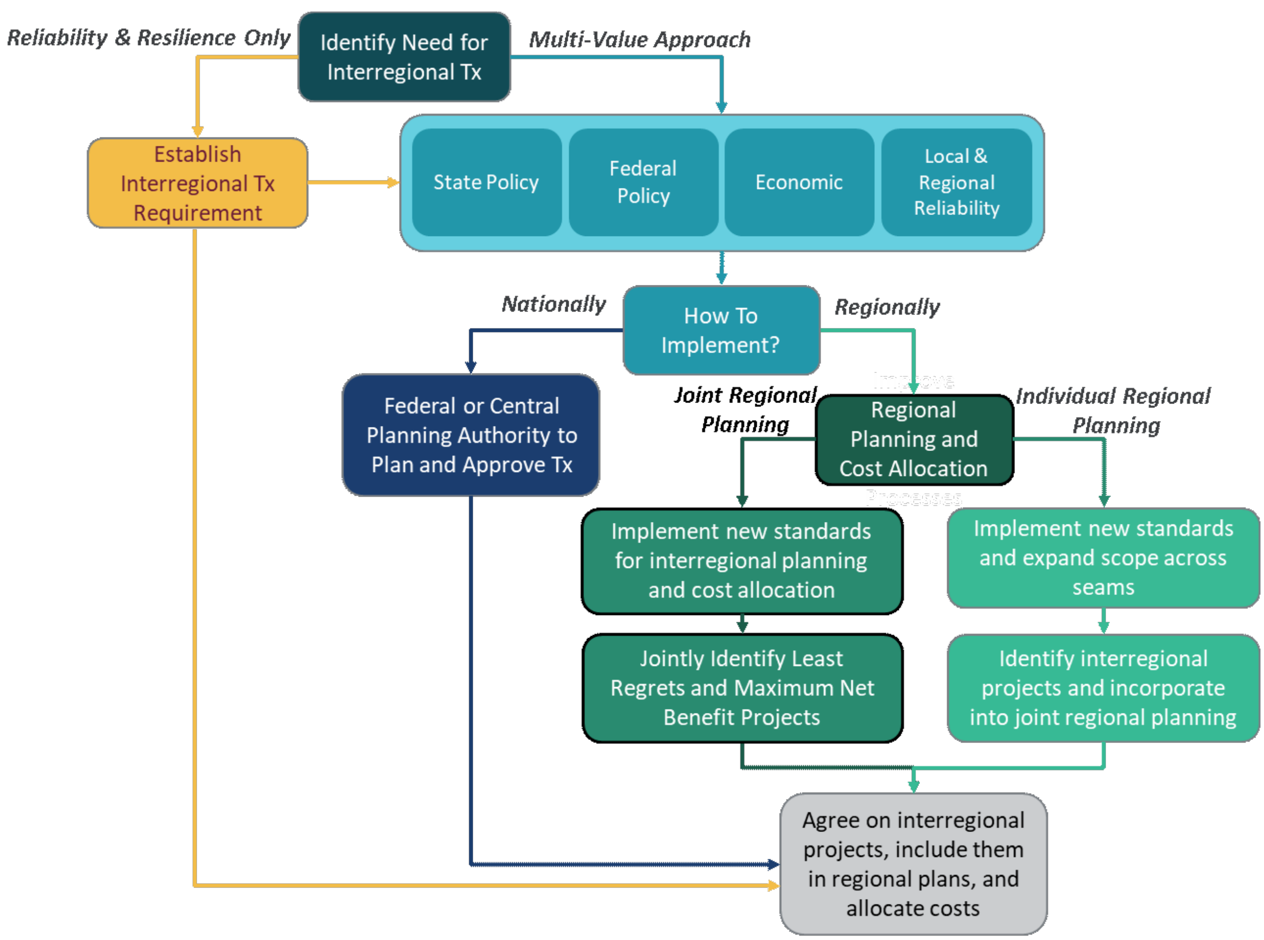
These recommendations are summarized in Figure 4 and include determining interregional transmission needs through several parallel planning pathways that can be pursued simultaneously:

- New reliability and resilience standards that would establish minimum interregional transfer capabilities, possibly implemented through NERC
- A new federal or central planning authority that would identify economic and public policy needs, including those driven by new state or federal policies, and has the authority to ensure projects are evaluated, permitted and sited, and ultimately built

[10] As we explain further below, reliability needs that are located along the seam with neighboring regions and, thus, might provide (different types of) benefits on both sides of the seam should be incorporated into the existing RTO process for identifying interregional needs and cost effective solutions.

- Enhanced joint interregional planning processes that would take a broader and proactive view of interregional project needs and benefits
- Improved individual regional planning processes that would allow the identification of interregional projects that could more cost effectively meet regional needs than available regional solutions and provide benefits to the neighboring system (and would specify the process for proposing such solutions to the neighboring region)

FIGURE 4. PARALLEL PATHWAYS TO ESTABLISHING THE NEED FOR INTERREGIONAL TRANSMISSION



Notes: "GI" refers to generator interconnection.

Improving and pursuing these interregional planning pathways will be increasingly important to assure resource diversity and cost-effective outcomes in a higher-renewable-generation power grid. For example, the experience in Germany shows that as renewable generation shares increase, the need for additional interregional transmission to help diversify renewable generation patterns increases as well. Germany recently approved a fourth major new high-capacity transmission line to more completely and cost-effectively integrate its southern region (with surplus distributed solar generation during sunny days and import needs when the sun is down) and its northern region (with surplus offshore wind generation during wind-rich periods and import needs during low-wind period).[11]

1. A New NERC Interregional Reliability & Resilience Standard

As shown in the left branch of Figure 4, one future pathway to determine the need for interregional transmission could be created through new reliability and resilience standards that aim to improve regional reliability and resilience through minimum interregional transfer capabilities. If designed correctly, and possibly implemented through NERC, they would require interregional transmission expansion where there is insufficient transfer capability between regions.

The increasing frequency of extreme weather events across the U.S.—most recently in the summer of 2020 and in February 2021—have certainly highlighted the key role that the interregional transmission system plays under extreme weather conditions and the ability to avoid outages and very-high-cost outcomes.[12] In response to those geographically-large weather events, FERC needs to direct NERC to incorporate additional reliability and resilience standards related to interregional transfer capability going forward. If it does, NERC will need to determine whether standards related to interregional transfer capability should be created and, if so, how planning regions would need to adjust their transmission-related reliability and resilience standards. System planning authorities would then need to determine how much additional interregional transfer capability is necessary to meet those standards.[13]

2. A New Federal or Central Planning Authority

Without a reliability or resilience need determined by new NERC interregional transfer capability requirements, interregional projects would primarily be driven by evaluating economic, reliability, and public policy requirements.[14] Economic and public policy needs can be driven by new state or federal

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[11] *See* Fourth North-South Power Line Required in Germany, Clean Energy Wire, August 7, 2019.

[12] In the past 12 months, major blackouts occurred in California and the Northwest in August 2020 due to an extreme heat wave across the Western U.S. and in Texas and the Midwest in February 2021 due to extreme cold weather conditions. Similar events occurred during the winter of 2014 and 2015 due to "polar vortex" events that affected the East Coast.

For a discussion of the benefit that additional interregional transmission would have provided during these extreme weather events, see Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, prepared for ACORE, July 2021, showing that The report shows that 1,000 MW of additional transmission capacity between Texas and its neighboring power regions would have provided nearly USD $1 billion dollars of value over just a few days during Winter Storm Uri.

[13] For example, the European Union has set interregional interconnection targets such that each country has in place transmission interties that allow at least 10% of the electricity produced by its power plants to be transported across its borders to neighboring countries. See: https://ec.europa.eu/energy/topics/infrastructure/electricity-interconnection-targets_en

[14] As we explain below, local and regional reliability needs located along the seam with neighboring regions should also be incorporated into the existing regional planning processes to evaluate if they, in combination with other regional and interregional needs, could be addressed more cost effectively through interregional transmission solutions.

policies. As has been proposed elsewhere,[15] the planning of interregional transmission projects to address any such state or federal needs could be undertaken either by a new federal planning authority—particularly in concert with any new federal clean-energy and transmission infrastructure investment legislation—or by a centralized, multi-regional planning authority established by the states. Figure 4 above shows this second pathway in blue.

At either the federal or interregional level, policymakers will need to determine whether such a new national or multi-regional planning authority would be housed at or authorized by FERC, the Department of Energy, or another agency. This new planning authority would need to consider several key issues, including (1) whether to address both federal and state policy objectives in addition to reliability, market efficiency, and broader economic objectives, (2) how to interface with states and RTOs, (3) whether it would primarily establish interregional needs that would then be addressed by the regions, or whether it would also identify cost-effective solutions for these needs, and (4) how costs of interregional planning and projects should be allocated across the regions or nationally.

Developing a federal planning process that can take a broader view of long-term interregional transmission needs and benefits than the existing RTO processes is worth considering, especially if the planning regions are unable or unwilling to lead this effort and adequately adapt their existing planning processes to address the transmission needs associated with the ongoing industry transition. The benefit of this approach would be that it would ensure the coverage of and participation from both RTO and non-RTO regions. It would also provide a unique forum for states to participate, including through modernizing and aligning their siting processes, which would make successful development of interregional transmission far more likely. Federal oversight and broader stakeholder participation would also help ensure independence of the decision-making process.

3. Improved Interregional and Regional Planning Processes

As shown with the two green pathways in the right half of Figure 4 above, existing regional (often RTO-administered) transmission planning processes could be improved through both (1) a top-down basis (dark green pathway) by mandating that the existing interregional planning efforts (conducted jointly by the neighboring regional planning authorities) produce and implement interregional transmission plans; and (2) a bottom-up basis (light green pathway) through expanded regional planning by the individual

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[15] For example, see ESIG's white paper, Transmission Planning for 100% Clean Electricity (2021): recommending "that a national transmission planning authority be created to develop and implement an ongoing transmission planning process. The United States needs an organization with the authority and responsibility to conduct national-level planning that transcends regional and parochial interests. Such an organization will not obviate the need for regional planning, but should work with the regional planners and others to coordinate top-down and bottom-up needs and optimize solutions according to the national public interest." *See also* Remarks of Allison Silverstein in FERC Docket AD21-13, recommending a "National Electric Transmission Authority [that, among other functions, would] have the ability to work with federal agencies and states to identify preferred resource zones, find appropriate routes for new intra- and inter-regional lines to connect resource zones to loads, and use federal funds to help pay a portion of the costs of new backbone transmission."

RTO and non-RTO regions so they are able to identify interregional transmission solutions that can cost-effectively address regional needs.

Expanding the scope of the individual regional planning processes to also consider interregional needs on a bottom-up basis would fill a crucial gap that currently exists between the existing joint interregional planning processes meant to identify valuable interregional transmission projects and the individual regional planning processes that do not consider whether interregional solutions could address their regional needs more cost-effectively. This gap in the existing regional planning processes can lead to an inability to identify beneficial interregional projects before less cost-effective regional solutions are approved and implemented—thereby preempting the opportunity to implement interregional projects that could more cost-effectively address multiple other needs on either side of the region's boundary.

A bottom-up approach under which individual regional planning authorities could identify interregional needs and solutions through their regional planning efforts would reduce barriers related to the sequencing of transmission planning for interregional needs, regional needs, generation interconnection requests, transmission service requests, and local transmission needs. The regional planning processes could be modified to (1) integrate addressing local and generation-related reliability needs into multi-value regional transmission planning and (2) include in that multi-value needs assessment an evaluation of whether interregional projects can address multiple needs near and across their seam more cost effectively than the incremental projects that address only a specific regional need.[16]

Simultaneously, the (top-down) joint interregional planning processes would need to be improved to more effectively identify whether interregional solutions would be more cost-effective than already-identified regional projects, in part by being able to address a wider range of needs for both of the neighboring regions. However, due to the near-term needs for some regional reliability projects (*e.g.* due the unexpected retirement of a generating plant), such an interregional assessment would either (a)

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[16] For example, NYISO has integrated consideration of aging facilities replacement into its public policy planning process. By doing so, NYISO determined that replacements of aging transmission infrastructure nearing its end of life could be avoided by major regional AC system upgrades. The avoided costs of the facilities replacements are considered as a benefit that partially covers the cost of the larger regional upgrade that also addresses public policy needs. *See* Newell, *et al.*, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, September 15, 2015.

Similar opportunities exist for integrating incremental transmission upgrades associated with generation interconnection needs into the regional and interregional planning process. For example, Enel recently presented a proposed approach under which generation-interconnection upgrades would be limited to narrow local needs at the interconnection point, while larger network upgrades are considered through a single, integrated regional transmission planning process. *See Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*, Enel Green Power, Working Paper, 2021. This approach of reducing the scope of generation-interconnection driven upgrades so regional network upgrades can be planned more holistically has already been used successfully in the United Kingdom for over a decade now. The "Connect and Manage" regime allows all new generation to apply for an accelerated connection based solely on the time taken to complete their local 'enabling works', with wider network reinforcement carried out after they have been connected through the regional transmission planning process. This process has dramatically reduced generation interconnection timelines by five years on average while allowing regional planning processes to more holistically identify the most cost-effective network upgrades. See, for example, Crouch, *Report on the enduring 'Connect and Manage' grid access regime,* Ofgem letter to The Rt Hon Andrea Leadsom MP Minister of State Department of Energy & Climate, December 14, 2015.

need to occur quickly, so that more cost-effective interregional solutions can be identified before the regional project is built; or (b) identify potential interregional needs and solutions ahead of time, such that they can be considered by the individual regions when developing projects to address a specific regional need. To the extent possible, however, planning processes should be more pro-active to, whenever possible, avoid outcomes in which predictable needs are ignored until they have to be addressed urgently, without sufficient time for a broader evaluation of cost-effective solutions through the regional and interregional planning processes.

As a part of an individual region's bottom-up approach to identifying interregional needs, each region would have to analyze its individual system needs by considering benefits that accrue to an expanded footprint that includes (all or portions of) neighboring regions. RTO planners noted during our stakeholder interviews that they already include neighboring markets in their planning models but only quantify benefits of possible transmission upgrades for their own footprint. Considering project benefits to the broader system would provide regional planners an additional opportunity to identify projects with interregional benefits that they could then propose as an interregional project to the neighboring region.

C. Improving Needs Assessment in Interregional Planning Processes

We recommend that the current interregional planning processes for identifying interregional needs—jointly conducted by neighboring planning regions—be modified in three ways to avoid the barriers that stakeholders identified in the current processes. Regional planning authorities should:

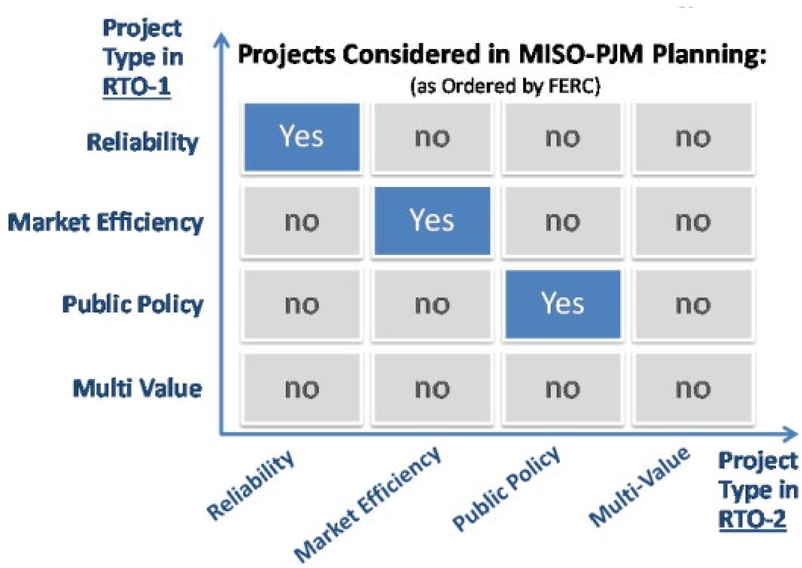
- Consider multiple drivers of need for interregional projects
- Remove any requirements that interregional projects address the same need for each of the neighboring regions
- Eliminate minimum size thresholds for interregional projects (if any), including those based on the voltage or cost

Some of the existing joint interregional planning processes (such as the PJM-MISO interregional planning process) allow only for the evaluation of transmission needs that are of the same type (*i.e.*, reliability, market efficiency, or public policy) in both regions. As illustrated in Figure 5,[17] these types of interregional planning processes thus may not allow for the evaluation of needs that differ across the regions, which can disqualify many valuable interregional projects from consideration.

[17] For a summary of the PJM-MISO interregional planning process, see Appendix C of Pfeifenberger, Chang, Sheilendranath, Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, Prepared for WIRES Group, April 2015.

By focusing only on projects that address reliability, market efficiency, or public policy needs in both regions, the planning process inadvertently excludes any interregional projects that, for example, would address reliability needs in one region but address market efficiency or public policy needs in the neighboring region. Unless the two adjacent regions categorize the interregional project in exactly the same way, the regions' interregional planning rules do not exist or may outright reject evaluating the project. More often than not, however, an interregional transmission project will provide multiple types of benefits even though these benefits may differ across regions. Thus, finding and approving transmission solutions solely based on reliability needs can lead to missed opportunities to build lower-cost or higher-value interregional transmission projects that could provide benefits beyond meeting reliability needs to reduce the overall costs and risks to customers in both regions.

FIGURE 5. SOME INTERREGIONAL PLANNING PROCESSES DO NOT ALLOW FOR THE EVALUATION OF PROJECTS THAT ADDRESS DIFFERENT NEEDS IN EACH REGION



To address this barrier, joint interregional planning processes should universally consider multiple drivers of need for identifying interregional projects. While only a reliability need may exist on one side of a seam, only market efficiency or public policy needs may exist on the other side. However, multiple needs and benefits are equally likely to exist on either side of the seam. Without recognizing that many transmission investments can address multiple needs, the industry will not be able to move beyond incremental solutions based on addressing reliability needs, leaving much unexplored value on the table, and increasing the overall costs and risks to customers and the power system as a whole. This means that interregional planning processes should encourage regional planning authorities to address their own regional needs through interregional projects if doing so is more cost effective overall.

Even where multi-value or multi-driver planning is possible under the currently-used interregional planning processes, interregional transmission projects may not be able to qualify under these processes due to different size and location thresholds used by neighboring regions in their regional and interregional planning processes. For example, interregional planning processes may exclude any upgrades below certain voltage levels (*e.g.*, 230 kV) or impose minimum project cost thresholds, which may eliminate from consideration any lower voltage or smaller projects even if they could cost-effectively address interregional needs.[18] Based on the definition of interregional transmission assets in FERC Order 1000, some of the current interregional planning processes may also exclude from consideration any projects that are physically located within a single region, even if the projects (such as an upgrade to a shared flow gate) would also address the needs of neighboring regions. This limitation, however, is no longer present in the PJM-MISO and MISO-SPP joint interregional planning process, which specifically allow for the consideration projects (such as upgrades to shared flow gates) that are located entirely within one of the regions but address needs in both regions.[19]

D. Proposed Improvements for Determining Interregional Transmission Needs

As illustrated in the pathways chart (Figure 4) above, improving the interregional planning processes to identify interregional transmission needs will require the following changes.

Add new pathways for interregional needs assessment: The process for identifying the need for interregional upgrades to the transmission system and/or identifying problems that interregional upgrades could resolve should be expanded to include additional pathways as outlined in Figure 4 above. The additional pathways could include (1) NERC establishing interregional reliability and resilience standards, (2) a federal planning authority or state-administered regional planning authorities identifying interregional economic and policy needs, and/or (3) individual regions identifying interregional needs through their existing regional planning process.

Expand options for interregional needs identification: The existing joint interregional planning processes should be improved to allow individual regions to identify and present interregional transmission projects for consideration by the other region, including for further evaluation through the joint interregional planning process. This would require interregional planning processes to clearly define how individual regions (or stakeholders within those regions) can identify interregional needs and nominate projects for consideration during the joint planning process.

Apply a multi-driver framework to identify interregional transmission needs: Interregional planning processes need to be expanded to allow for the identification of multiple drivers of needs and to be flexible enough to accommodate projects that address different needs in different regions (*e.g.*,

[18] SPP has attempted to approach interregional planning more broadly and include reliability, economic, and public policy projects at all voltage levels. In contrast, MISO applies a narrower perspective and proposed limiting interregional planning solely to “market efficiency projects” at a voltage level of 230 kV or above.

[19] SPP-MISO and MISO-PJM Joint Operating Agreements available here: https://www.misoenergy.org/planning/interregional-coodination/

reliability needs in one region but public policy needs in the other). This will require expanding the needs identification process beyond the current narrow approach of identifying reliability, economic, or policy needs. Instead, the full set of interregional needs across the neighboring regions should be considered as a whole to determine whether certain projects may be able to address one or more needs across both regions.

Reduce project qualification thresholds: Regional planning authorities should eliminate the use of minimum-size thresholds based on voltage level, total cost, or total benefits for interregional planning as even small projects might offer benefits that significantly exceed their costs. The definition of an interregional project should include both projects that physically cross the seam (as interregional projects are currently defined in Order 1000) or that are physically located within one region but can address the needs of and provide clear benefits to both regions. Examples of the latter type of interregionally-beneficial projects are upgrades to shared flow-gates that are located whole in one region but also constrain flows of the neighboring region.

E. Key Stakeholder Action Items

To implement the suggested improvements to interregional planning and needs assessment, planners and policymakers need to pursue the following action items:

FERC:

- Require regional planning authorities to amend their joint interregional planning processes to identify interregional transmission needs based on a scenario-based, multi-driver, multi-value analysis.
- Mandate that interregional planning processes develop a procedure for individual regions to incorporate interregional solutions into the standardized regional planning processes.
- Require multi-driver analysis of interregionally-beneficial projects regardless of size or project location.
- Update NERC reliability and resilience standards to require necessary levels of interregional transfer capability.

Federal Policymakers:

- Develop a multi-regional planning process and consider establishing a federal planning authority (possibly under FERC or DOE) for identifying federal policy-related needs for increased transfer capability between regions, especially needs associated with meeting federal clean energy and decarbonization objectives.

State Policymakers and Regulators:

- Support alternative pathways for interregional planning efforts that can more cost-effectively support state policy goals.
- Consider whether multi-state regional planning authorities are necessary for identifying policy-related needs for increased transfer capability between states and regions in the absence of a federal planning process.

Regional Planning Authorities:

- Implement new standards for interregional needs identification
- Work with joint/interregional planning authority bodies to adopt multi-driver needs determinations (consistent with implementing proven methods that quantify a broad range of transmission benefits and develop portfolio-based cost allocation methods that allocate costs commensurate with benefits).
- Incorporate into interregional transmission planning processes a procedure for proactively identifying when interregional solutions address multiple needs in a more cost effective manner.
- Commence regional planning analysis across a larger footprint that includes neighboring regions to identify interregional solutions that more cost-effectively address regional needs and implement those as part of the interregional planning process.

Transmission Owners

- Support planning authorities in their efforts to identify interregional transmission needs

IV. Quantifying the Full Benefits of Interregional Transmission

Most economic analyses used in transmission planning rely primarily on traditional applications of production cost simulations to determine whether the production cost savings offered by a transmission project exceed the project's costs. These production cost savings, adjusted for wholesale purchases and sales (or imports and exports), are mostly composed of fuel cost savings. Other transmission-related benefits are either not considered by regional planners or they lack the metrics and tools to quantify those benefits. Interregional benefits analyses are additionally challenging since the models, tools, and benefits metrics used by neighboring planning regions typically are not well-aligned.

Stakeholders highlighted in our interviews that the narrow scope of benefits that are currently included in regional planning processes is a significant barrier to identifying and approving both regional and interregional transmission projects. They also noted that the narrow scope of benefits quantified creates barriers in cost allocation (which we address further in the next section) since costs can only be allocated to individual regions if the benefits are recognized by the planning authorities and stakeholders of those regions.

In some planning regions, the analysis of economic benefits has expanded well beyond production cost savings for at least a subset of transmission projects evaluated within the regional planning process. For example, as shown in Table 3 below, when MISO planned its portfolio of Multi-Value Projects a decade ago, it considered reduced operations reserves, reduced planning reserves, reduced transmission losses, reduced renewable generation investment costs, and reduced future transmission investment costs in its benefits analysis in addition to the standard production cost savings. Table 3 below summarizes the experience with expanded benefits analysis employed by SPP, CAISO, and NYISO for certain transmission projects. To be effective, analysis and quantification of a broader set of transmission-related benefits must also be applied to interregional planning efforts.

TABLE 3: EXAMPLES OF EXPANDED TRANSMISSION BENEFITS ANALYSIS

SPP 2016 RCAR, 2013 MTF	MISO 2011 MVP ANALYSIS	CAISO 2007 TEAM ANALYSIS OF DPV2 PROJECT	NYISO 2015 PPTN STUDY OF AC UPGRADES
Quantified 1. **production cost savings** value of reduced emissions reduced AS costs 2. avoided transmission project costs 3. reduced transmission losses capacity benefit energy cost benefit 4. lower transmission outage costs 5. value of reliability projects 6. value of meeting policy goals 7. Increased wheeling revenues	**Quantified** 1. production cost savings 2. reduced operating reserves 3. reduced planning reserves 4. reduced transmission losses 5. reduced renewable generation investment costs 6. reduced future transmission investment costs	**Quantified** 1. production cost savings and reduced energy prices from both a societal and customer perspective 2. mitigation of market power 3. insurance value for high-impact low-probability events 4. capacity benefits due to reduced generation investment costs 5. operational benefits (RMR) 6. reduced transmission losses* 7. emissions benefit	**Quantified** 1. production cost savings (includes savings not captured by normalized simulations) 2. capacity resource cost savings 3. reduced refurbishment costs for aging transmission 4. reduced costs of achieving renewable & climate goals
Not Quantified 8. reduced cost of extreme events 9. reduced reserve margin 10. reduced loss of load probability 11. increased competition/liquidity 12. improved congestion hedging 13. mitigation of uncertainty 14. reduced plant cycling costs 15. societal economic benefits	**Not Quantified** 7. enhanced generation policy flexibility 8. increased system robustness 9. decreased nat. gas price risk 10. decreased CO2 emissions 11. decreased wind volatility 12. increased local investment and job creation	**Not Quantified** 8. facilitation of the retirement of aging power plants 9. encouraging fuel diversity 10. improved reserve sharing 11. increased voltage support	**Not Quantified** 5. protection against extreme market conditions 6. increased competition and liquidity 7. storm hardening and resilience 8. expandability benefits

Sources: SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, Benefits for the 2013 Regional Cost Allocation Review, July, 5 2012; Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011; CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity; Newell, *et al.*, Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015.

A consolidated summary of the benefits of transmission investments that have been considered and quantified by RTOs and others in transmission benefits assessments are listed in Table 4 below.[20] The wide range of benefits that can be quantified but often are not included in the analysis of economic and public policy transmission projects include reduced system losses, the value of increased system reliability (or reduced reserve margin requirements), access to lower-cost conventional and renewable generation, and increased wholesale-market competition, among others.

TABLE 4. ELECTRICITY SYSTEM BENEFITS OF TRANSMISSION INVESTMENTS

Benefit Category	Transmission Benefit
1a. Traditional Production Cost Savings	Production cost savings as currently estimated in most planning processes
1b. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced costs during extreme events and system contingencies
	v. Mitigation of weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic “Day 1” market representation
2. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
3. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
4. Market Benefits	i. Increased competition
	ii. Increased market liquidity
5. Environmental Benefits	i. Reduced expected cost of existing or potential future emissions regulations
	ii. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

Most regional planning processes that are focused mostly on traditional production cost savings are not taking advantage of available industry experience and well-tested practices in quantifying an expanded

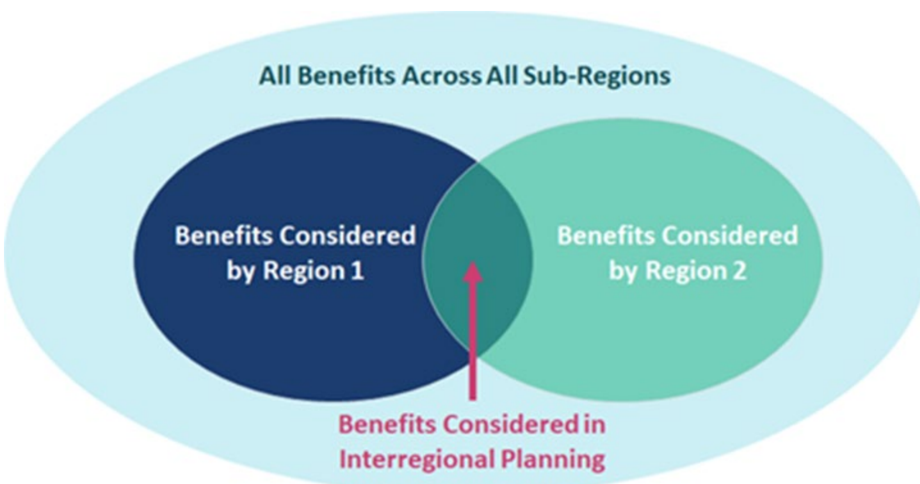
[20] Pfeifenberger *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021. This report also summarizes proven industry experience with a wide range of benefit metrics for the evaluation of transmission projects and documents the approaches taken and well-tested practices for quantifying the benefits associated with these metrics. A good discussion of benefit metrics and methods for quantifying them is also presented in SPP, *Regional Cost Allocation Review Report for RCAR II*, July 11, 2016 (Section 6) and SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.

set of transmission-related benefits. The benefit-cost assessment of regional and interregional planning processes thus needs to expand beyond focusing solely on the traditionally-quantified production cost savings to a more holistic view of benefits that accurately reflect the benefits of proposed transmission projects.

Despite the significant experience in quantifying a broader set of benefits across the industry, several stakeholders, especially state policymakers and customers, were not familiar with other regions' experience with considering and quantifying many of these benefits. As a result, the full set of benefits is not typically considered in most regional transmission planning processes.

Interregional transmission planning is especially challenging given the tendency of neighboring regions to evaluate interregional projects based only on the subset of benefits that are common to the planning processes of each of the respective regions involved. In some cases, the respective regions reviewing an interregional project might have agreed for project evaluation to use only the subset of criteria and benefit metrics that are common to both regions. However, such an approach tends to disadvantage interregional projects because the jointly agreed-upon criteria and metrics generally will tend to represent the least common denominator subset of the criteria and metrics used in the adjoining regions. Worse, as shown in Figure 6, the range of benefits considered for interregional projects tends be more limited than even the narrow scope of benefits considered in intra-regional planning processes.

FIGURE 6. THE "LEAST COMMON DENOMINATOR" CHALLENGE OF BENEFIT-COST ANALYSIS FOR INTERREGIONAL PROJECTS



Similarly, current interregional planning processes do not recognize the unique benefits often offered by an expanded interregional transmission system, which include increased load and resource diversity and the geographic diversification of load and renewable generation variability and forecasting uncertainty.[21]

Current benefit analyses of regional planning processes tend to over-rely on "base case" projections, with a focus on current trends and associated needs. The utility industry faces considerable uncertainties on both a near- and long-term basis. These uncertainties should be considered explicitly in transmission planning. A base case planning approach does not recognize the value of transmission investments to address challenges and high-cost outcomes in futures that deviate from the business as usual case, such as increased environmental regulations or market rule changes, higher natural gas and emissions prices, substantive shifts in generation or load, or infrequent but extreme weather conditions. The consideration of near-term uncertainties—such as uncertainties in loads, volatility in fuel prices, and transmission and generation outages—is important because the value of the transmission infrastructure is generally disproportionately concentrated in periods of more challenging, or extreme, market conditions. As the high economic costs and lost lives due to extended power outages during winter storm Uri demonstrated most recently, insufficient interregional transmission and being exposed to plausible risks can be extremely costly.

The consideration of long-term uncertainties—such as industry structure, new technologies, fundamental policy changes, and other shifts in market fundamentals—is important for developing robust transmission plans and investment strategies, valuing future investment options, and identifying least-regrets projects. A least regrets planning approach, however, needs to consider *both* (1) the possible regret that a project may not be cost effective in a particular future; *and* (2) the possible regret that customers may face excessive costs due to an insufficiently robust transmission grid in other futures.[22]

Another recent example of system planners failing to adequately consider the implications of insufficient expansion of interregional transfer capability to address extreme market conditions is the August 2020 blackouts in California. The final root cause analysis released by California policymakers concluded that "transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint" and "more energy was available in the north than could be physically delivered."[23] CAISO had similarly concluded after the 2000−01 California power crisis that the crisis and

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[21] Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, BU-ISE, October 14, 2020.

[22] For a more detailed discussion on how transmission planners can use scenarios to pro-actively consider long-term uncertainties and the potentially high cost of insufficient infrastructure and associated risk mitigation benefit in transmission planning, see Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015, pp. 9−19.

[23] CAISO, CPUC, and CEC, *Final Root Cause Analysis Report: Mid-August 2020 Extreme Heat Wave*, January 13, 2021, p. 48.

its extremely high costs could have been avoided if more interregional transmission capability had been available to the state.[24]

An important limitation to accurately quantifying the total benefits of transmission is caused by the fact that most planning analyses of economic benefits are undertaken only for normal system conditions that do not include challenging events such as cold snaps, heat waves, fuel price spikes, transmission outages, or unusual generation outages.[25] It is important, however, to quantify the benefits of avoiding high-cost outcomes during such challenging economic, weather, and system conditions that could occur in every possible future over the long life of the investment. Ignoring these situations means that, without the investment, the costs and risks imposed on consumers and other market participants will tend to be much higher than typically estimated. Even in cases where a broader set of future scenarios are developed for transmission planning, system planners and stakeholders often still tend to focus primarily on the base case for driving transmission needs.

A major limitation identified by stakeholders to developing future scenarios is the lack of input from the states on how they plan on achieving their policy goals, especially those related to clean energy. This is particularly important since states often have specific goals for local renewable energy resource development that are not well articulated or challenging to incorporate into regional and interregional planning processes. One of the key drivers of the MISO MVP process was that state representatives were requesting that MISO evaluate transmission solutions that could cost-effectively meet the region's combined state-level renewable portfolio standards by integrating a combination of local and regional renewable resources. A high-level outlook of how states wish to pursue meeting their goals, or a more detailed set of scenarios, would greatly improve the ability of regions to plan their future system without having to develop a specific portfolio of resources to do so.

In addition, barriers can be created due to the disjointed nature of the existing interregional and regional planning processes. For example, interregional transmission projects may be subjected to three separate benefit-cost thresholds: a joint interregional benefit-cost threshold as well as each of the two neighboring region's individual internal planning criteria. This means, for example, that projects that pass each region's individual benefit-cost thresholds may fail the threshold imposed through the least-common denominator approach to interregional planning; or projects that pass the benefit-cost threshold of the interregional planning process may be rejected because they may fail one of the individual regions' planning criteria. In combination with evaluating only a subset of benefits of a few

[24] CAISO estimated that if significant additional transmission capacity had been available during the California energy crisis from June 2000 to June 2001, electricity customer costs would have been reduced by up to $30 billion over the 12-month period during which the crisis occurred. CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004, p. ES-9.

[25] For example, SCE analyzed the benefits of the Palo Verde to Devers 2 (PVD2) under a range of system conditions that significantly increased the value of the project. Similarly, ERCOT considered a range of load and natural gas price sensitivities in its evaluation of the Houston Import project. For a summary of these approaches, see Appendix A and Appendix B of Pfeifenberger, Chang, Sheilendranath, Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, Prepared for WIRES Group, April 2015.

scenarios of future market conditions, this adds to the challenge of approving even very valuable projects.

A. Proposed Improvements for Quantifying Project Benefits

We offer the following recommendation for consideration by planners and policymakers when evaluating the merits of transmission projects.

Establish minimum standards for improved benefits analysis: Developing a set of minimum standards for interregional planning processes would set the stage for analyzing a broader set of benefits and metrics. Two regions involved in a joint interregional planning process do not need to rely on the same exact set of benefits and costs may ultimately differ because the project beneficiaries in each region may differ—but in order to identify interregional project needs, parties need to be planning on the same page.[26]

Our recommended principles and minimum standards for determining the benefits of interregional transmission projects are:

1. Interregional projects (either as single projects or a group of projects) may offer combinations of different types of benefits and cost-effectively address multiple needs;
2. It is possible that entirely different sets of needs are addressed in and benefits accrue to each region from a particular interregional project;
3. The benefits and metrics used for the evaluation of interregional projects by each region needs to include the full set of benefits and metrics considered in each region's local and regional transmission planning process;
4. Each region needs to have the flexibility to include, in addition to the full set of benefit metrics used for its regional planning effort, some or all of the benefits and metrics used by the other region even if these benefits and metrics are not currently used in the region's internal transmission planning process;
5. The regions need to recognize that interregional projects may offer unique benefits beyond those currently considered in either region's internal transmission planning process. If deemed significant, the regions need to develop metrics to capture any such additional interregional-related benefits;

[26] These guiding principles have been updated from similar principles developed in a 2012 report on interregional planning and cost allocation. *See* Pfeifenberger and Hou, Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning, prepared for SPP Regional State Committee, April 2012. The report includes several case studies illustrating the application of these principles and includes proposed changes to the SPP Joint Operating Agreement (JOA) with neighboring planning authorities, which would be necessary to implement these principles.

6. The regions need to recognize that additional benefits may be documented as more experience is gained with the planning and evaluation of interregional projects. If deemed significant, the regions need to develop metrics to capture any such additional interregional-related benefits;
7. The regions must prioritize interregional projects that would avoid or delay the cost of (1) transmission upgrades needed to satisfy generation interconnection and transmission service requests; (2) transmission upgrades that would have to be planned now to address their already-known local and regional needs; and (3) transmission upgrades that likely would be needed in the future to meet local and regional needs (including the replacement of aging infrastructure); and
8. If minimum benefit-to-cost thresholds are utilized, they should not exceed 1.25. Lower thresholds should be acceptable if some of the benefits of interregional transmission projects are recognized qualitatively but have not been quantified.

More specifically, we further recommend that the scope of benefit-cost analyses of interregional transmission projects include the following:

Capture unique interregional benefits: Interregional planning processes need to recognize that projects might offer additional benefits beyond those currently considered in either region's internal transmission planning process, such as incremental wheeling revenues or benefits from increased reserve sharing capability. Planning processes must define a comprehensive but flexible set of project evaluation criteria and benefit metrics. Regions should also recognize that interregional projects might serve to avoid or delay the cost of other upgrades, such as projects included in each region's existing plans, or upgrades that might be needed in the future to meet local or regional needs, or to satisfy generation interconnection or transmission service requests.

Consider all regional benefits: To avoid a least-common-denominator approach to interregional planning, each of the neighboring regions, at a minimum, should evaluate its share of an interregional project's benefits by considering all types of benefits that are used in the region's internal transmission planning process. Doing so will ensure that the total benefits considered in the interregional planning process are at least equal to the sum of the benefits that each regional planning authority would determine for a regional project in its own footprint. In this way, benefits and metrics considered in interregional planning would at least be consistent with the reliability, operational, public policy, and economic benefits considered in the individual regions, even if these benefits are not defined and measured the same way in each region. Interregional planning processes must also recognize that interregional projects might offer unique benefits beyond those currently considered in either region's internal transmission planning process, such as incremental wheeling revenues that could offset some portion of the costs associated with the transmission project or benefits from increased reserve sharing capability.

Address uncertainties and long-term benefits: The analytical approaches applied to interregional planning must (1) be proactive by considering all base case future generation required to address public policy needs and (2) look beyond base cases or business-as-usual cases and explicitly consider a broader range of plausible market conditions, system contingencies, and public policy environments. Gaining buy-in from stakeholders on the approach for developing alternative scenarios and specific assumptions is critical to stakeholders supporting the results of the study.[27] Doing so will better capture the short- and long-term flexibility benefits and insurance value that a more robust interregional transmission infrastructure can offer in terms of shielding customers from high-cost outcomes. Stakeholders should urge planners to expand least regrets transmission planning from (1) identifying only those projects that are beneficial under most circumstances to (2) also considering the potential regrettable circumstances that could result in very high-cost outcomes because of inadequate infrastructure.[28]

The high-cost regret of not having sufficient infrastructure has been illustrated during the 2021 winter storm Uri, an where additional 1,000 MW of interregional regional transmission between Texas and neighboring regions could have provided over a $1 billion of value in only four days, which would have been sufficient to cover the entire cost of the additional transmission.[29] This example shows that the cost of not having built more transmission must be considered in least regrets planning as it can be extremely high. Another example includes the 2000-2001 California Power Crisis, where a previously considered transmission upgrade ("Path 15") that was rejected based on limited need could have reduced customer costs by over $200 million in only December 2000 had it been in service.[30] Given the project's ultimate $250 million cost and the fact that the crisis lasted into the first quarter of 2001, the line would have paid for itself in just one year.

Alternatively, in evaluating the Paddock-Rockdale Project, the American Transmission Company evaluated seven plausible futures, spanning a wide range of long-term uncertainties. This analysis of multiple scenarios of plausible futures showed that the estimated benefits ranged widely across sets of plausible futures. While the project was projected to be clearly beneficial in most (but not all) futures, the analysis also showed that not investing in the $136 million project could leave customers up to $700

[27] Chang, Pfeifenberger, Newell, Tsuchida, Hagerty, Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process, Prepared for ERCOT, October 2013, pp. 62–64.

[28] *See* Pfeifenberger, Chang, and Sheilendranath, Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, prepared for WIRES, April 2015.

This report provides a number of examples of how transmission benefits vary across different plausible futures and uncertainties. For example, a planning analysis of the Paddock-Rockdale transmission project in Wisconsin evaluated the long-term benefits of the project under seven plausible futures. These results show that the estimated benefits can span a wide range when different future scenarios are considered: while the project's benefits fall short of its costs in one of the seven futures, not investing in the project with a cost of $138 million would potentially leave customers $700 million worse off in two of the seven futures evaluated. *Id.* at 17.

Similarly, a scenario-based analysis by CAISO showed that a transmission project with an annual cost of $70 million is not only cost effective in all of the evaluated cases with an average benefit-cost ratio of 1.4, but also eliminates a 10% chance that customers would be exposed to $300 million to $750 million in higher annual costs without the project. *Id.* at 14–17.

[29] Caspary, *et al.*, Disconnected: The Need for a New Generator Interconnection Policy, prepared for Americans for a Clean Energy Grid (ACORE), January 2021.

[30] California ISO, 2001, "Path 15 Upgrade Cost Analysis Study," February 16, 2001.

million worse off in two of seven plausible futures.[31] Recognizing that benefits exceed costs in most of the seven futures, that benefits were projected to fall just short of covering project costs in only two futures, but because the project can avoid very-high-cost outcomes in another 2 of the 7 futures, the Wisconsin Public Service Commission unanimously approved the project.

These examples show that a robust transmission grid offers insurance value. And stated in insurance terms: planners and policy makers must move from focusing solely on the cost of insurance and the regret of having bought it and not needed it (*I.e.*, one type of "regret") to also analyzing the potentially very high cost of not having insurance when it is needed (*I.e.*, include the "regret" of not having bought it).[32]

Prohibit more stringent cost-benefit thresholds: The benefit-to-cost thresholds to interregional projects must be no more stringent than those applied within each region. Since interregional projects are projects that regions evaluate jointly, a single joint benefit-to-cost threshold should be sufficient. If the regions jointly find that a certain interregional project or portfolio of projects offers benefits in excess of costs, the participating regions need to agree on a cost allocation such that each region enjoys a share of the overall benefits that exceeds its share of the costs. Having a single benefit-to-cost threshold for the participating regions would help avoid reaching different conclusions simply because the thresholds are different in the participating regions. If minimum benefit-to-cost thresholds are utilized, they must not exceed the regional thresholds. However, if some of the benefits of interregional transmission projects are recognized only qualitatively but are not quantified, reduced benefit-cost thresholds (such as 1.0) should be acceptable to account for this.

B. Key Stakeholder Action Items

To implement the suggested improvements to capture the full range of benefits in planning, we propose the following action items for key planners and policy makers:

FERC:

- Reform transmission planning requirements to capture the wide-range of benefits of transmission investments and the need for transmission planning processes to account for those benefits
- Require planning authorities to incorporate a wide-range of transmission benefits across and implement least-regrets in planning processes
- Require transmission planning processes to proactively incorporate both short- and long-term uncertainty through scenario-based planning using a broad range of plausible futures to capture

[31] Pfeifenberger, *et al.*, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES, April 2015.

[32] *See* Trabish, 3 serious failures in transmission planning and how to fix them, Utility Dive, May 4, 2015.

long-term uncertainties and sensitivities that can capture short-term uncertainties and challenges, such as high-cost weather events and market conditions

State Policymakers and Regulators

- Engage with RTOs and non-RTO regional planning authorities to modify the approach to analyzing benefits
- Develop scenarios for regions to consider in interregional planning efforts, including with future resource mixes that achieve existing state policy mandates and plausible new future policy goals

Regional Planning Authorities

- Work with neighboring regions to develop and implement interregional planning reforms, including a shared set of benefit metrics and methodologies used for in both regions
- Expand capabilities to analyze a wide-range of benefits of interregional transmission projects

Transmission Owners

- Empower stakeholders and consumers in developing a more inclusive set of benefit metrics
- Allow planning authorities to consider the value of avoided local reliability and regional projects when analyzing the benefits of larger interregional projects

V. Establishing a Flexible Interregional Cost Allocation Framework

Cost allocation across regional boundaries is perhaps the biggest hurdle for successful development of interregional projects. Customers and transmission owners are unwilling to bear the costs for individual transmission projects that they feel do not provide tangible benefits to them and their customers. However, one of the fundamental causes of the challenges created in the cost allocation process is that the benefits of interregional projects or portfolios of projects often are well-articulated, documented with sufficient detail, and quantified such that the entities who would have to pay for the new transmission are willing to support the project.

Even if the approach to estimating the overall benefits of interregional transmission projects is adequate, the lack of sufficiently detailed, actionable, but flexible principles and guidelines for cost allocation creates a significant barrier to interregional planning. This barrier can be further magnified if cost allocation is not aligned with project ownership interests and the assignment of transmission rights, and is determined on a project-by-project basis.[33]

A key function of any successful cost allocation framework is the clear articulation of project evaluation criteria and benefit metrics. As described in the previous section, benefits can include meeting policy goals, avoided costs, and achieving other system improvements and savings. The specified metrics may capture these benefits in either monetary or non-monetary terms. FERC's six cost allocation principles defined under Order 1000 provide a good starting point, but these do not provide enough guidance to be actionable by themselves.

Generally, there are six cost allocation methods and recovery mechanisms that have been considered at the regional level:

1. *License plate:* each utility recovers the costs of its own transmission investments usually located within its footprint.
2. *Beneficiary pays:* Various formulas that allocate costs of transmission investments to individual TOs that benefit from a project, even if the project is not owned by the beneficiaries. TOs then recover allocated costs in their License Plate tariffs from own customers.
3. *Postage stamp:* transmission costs are recovered uniformly from all loads in a defined market area (*e.g.*, RTO-wide in ERCOT and CAISO). In some cases (*e.g.*, SPP, MISO, PJM) the costs of certain project types are allocated uniformly to TOs, who then recover these allocated costs in their License Plate tariffs.
4. *Direct assignment:* transmission costs associated with generation interconnection or other transmission service requests are fully or partially assigned to the requesting entity. (Innovative variance: CAISO's Location Constrained Resource Interconnection (LCRI) policy that offer up-front system-wide funding, with pro-rata interconnection costs that later charged back to generators as the interconnect).
5. *Merchant cost recovery:* the project sponsors recover the cost of the investment outside regulated tariffs (*e.g.*, via negotiated rates with specific customers); largely applies to DC lines where transmission use can be controlled.
6. *Co-ownership:* benefitting transmission owners co-own the facility, with each recovering costs through rate base treatment; this "one operator shared transmission ownership and rights" model has been employed for the CAPX2020 transmission upgrades by Minnesota utilities and is often used in WECC.

[33] Many transmission owners prefer owning (and earning a return on ratebase) the transmission facilities whose costs are recovered from their customers. They tend to be more reluctant to recover from their customers the costs of transmission owned by others. They will also have a strong preference for obtaining physical or financial rights to the transmission capabilities of facilities they have to pay for.

A successful approach to cost allocation at the interregional level will need to be flexible enough to accommodate different types of interregional projects (*e.g.*, reliability, economic, and public policy projects) for different types of neighboring regions and entities (*e.g.*, RTO and non-RTO regions, FERC-jurisdictional, and non-jurisdictional entities) and specific enough to be actionable without being overly restrictive and formulaic. To achieve this balance, cost allocation needs to be completed for a portfolio of interregional and regional projects rather than a single project[34] and cost allocation agreements must include guidelines for how benefit metrics will be applied to support cost allocation. For example, cost allocation guidelines might specify that the costs of interregional transmission projects should be allocated based on the share of monetized benefits, in proportion to the present values of project benefits received by each entity. Alternatively, the guidelines could allow for cost allocation to be based on more qualitative, non-monetized benefits and cost-causation ratios. As documented by the approval of portfolio-based regional cost allocation framework in MISO and SPP shows, FERC Order 1000 does not require that the cost of each project is allocated strictly based on its benefits as long as the cost allocation for a portfolio of projects is roughly commensurate with overall benefits.

As more experience with the cost allocation of interregional projects is gained, planning regions may pre-specify cost allocation options. These pre-specified formulaic cost allocations would be based on specific metrics for the evaluation of interregional projects and a pre-specified cost allocation methodology that formulaically relies on these benefits and metrics. Projects that do not fit the pre-specified options would be considered under the more flexible cost allocation principles.

A. Proposed Improvements for Interregional Cost Allocation

We propose for further consideration by transmission planners and policymakers the following minimum standards, cost allocation mechanisms, and payment mechanisms for interregional transmission projects.

Minimum Standards: Rather than resolve interregional cost allocation formulaically or on a case-by-case approach, we recommend the inclusion of a core set of minimum standards to serve as the overarching framework for developing transmission cost allocation for interregional projects. Integrating the cost allocation requirements of FERC Order 1000, we propose the following principles and requirements:

1. Costs allocated for a portfolio of interregional projects must be at least roughly commensurate with the total benefits that the portfolio provides to each region; neither region shall be allocated cost without receiving benefits.

[34] As explained below, this is because a portfolio-based cost allocation approach has the advantage that the portfolio-wide benefits will be more evenly distributed, which allows for less complex cost allocation approaches while still ensuring that the sum of costs allocated is roughly commensurate with the sum of benefits received.

2. Cost allocation methodologies and identification of benefits and beneficiaries must be transparent.
3. Different cost allocation methods may be applied to different types of needs addressed (*e.g.*, reliability, economic, or public policy needs) or different portions of transmission facilities.
4. Regions must utilize the quantified and, if possible, monetized benefits in determining the cost allocation approach (but they must also recognize non-monetized and non-quantified benefits) for portfolios of interregional projects in assessing overall reasonableness of proposed cost allocations.
5. The monetized reliability, load serving, and/or public policy benefits of interregional projects should be at least equal to the avoided cost of achieving the same total benefits through local or regional upgrades.
6. The monetized benefits and share of costs allocated to each region should be sufficient to support the interregional projects' approval through each region's internal planning process.
7. Project costs allocated to each region should be recovered via the existing local and regional cost allocation and recovery process of each region.

Several of the above interregional cost allocation standards simply implement Order 1000 requirements. However, standards Nos. 1, 4, 5, and 7 go beyond Order 1000 requirements. For example, the proposed standards No. 1 and No. 4 would apply cost allocation to portfolios of projects rather than individual projects. The portfolio-based cost allocation approach has the advantage that portfolio-wide benefits will tend to be more broadly and more evenly distributed, which allows for less complex cost allocation approaches while still ensuring that the sum of costs allocated is roughly commensurate with the sum of benefits received.[35] Proposed standard No. 4 reflects the expectation that cost allocations be based mostly on quantifiable benefits and thus requires that regions attempt to quantify and monetize the identified benefits based on the metrics provided. It also states, however, that non-monetized and non-quantified benefits must still be considered at least qualitatively in the regions' assessment of the overall reasonableness of any proposed cost allocations. Standard No. 5 provides an approach for estimating the reliability, load serving, public policy, and other similar benefits of interregional projects by proposing that the monetized value of such benefits be at least equal to the avoided cost of achieving the same benefits through cost-effective local or regional transmission solutions. And standard No. 7 goes beyond Order 1000 requirements by specifically addressing fairness concerns related to the potentially different scope of benefits that the proposed framework defines for different regions.

Standard No. 6 requires that the monetized benefits of an interregional project, when compared to its allocated costs, are sufficient to support the project's approval based on the criteria that are used in

[35] This approach is widely used for infrastructure costs, such as roads or distribution systems. The portfolio-based approach has also been apply taken, for example, by SPP for the highway-byway cost allocation of projects approved through its Integrated Transmission Planning (ITP) process and MISO for the postage-stamp-based cost allocation of its portfolio of Multi-Value Projects (MVP). While SPP and MISO have demonstrated that the benefits of portfolio of projects are roughly commensurate with allocated costs, the cost allocation approach would not meet that standard for individual ITP and MVP projects. Note, however, that the approval of individual projects or synergistic groups of projects still needs to be based on the need for and total benefits of the individual projects.

each region's internal transmission planning process. This means even if one region were to utilize different definitions of project benefits, the project will still be beneficial to the region considering both its share of benefits as well as its share of costs. While it is still possible that a region realizing a broader scope of benefits would end up with a larger share of allocated costs, the region would not be asked to approve an interregional project at terms that are any less attractive than the terms that would be considered for local and regional projects in the region's internal planning process. To successfully improve interregional planning, however, regions will thus have to improve the flexibility of their regional planning processes such that they are able to use a full set of holistic criteria to evaluate transmission-related benefits across a set of future scenarios that reasonably span long-term uncertainties. Commonality of the suite of benefits being evaluated, even if the applicable benefits or ultimate values differ across regions, is necessary to prevent one region's failure to quantify many of the benefits of transmission projects in its regional planning process to be compounded into a failure to support and commensurately share the costs of valuable interregional transmission projects altogether.[36]

Cost allocation mechanisms: Interregional planning processes must pre-specify cost allocation mechanisms but ensure they remain flexible enough to achieve cost allocations that recognize differences in project drivers and benefits across the regions. For example, the planning process may specify that cost allocation to each region should be based on one or a combination of:

- The share of the projects' total benefits received by each region as a proportion of the sum of the regions' total benefits received consistent with specified principles and benefit metrics.
- If non-monetary ratios are reasonably proxies for shares of received benefits or are roughly proportionate to benefits received, cost allocation can also be based on:
  - The share of projects' physical location in each Party's footprint (*e.g.*, shares of circuit miles or investment dollars).
  - The share of each region's relative contribution to the need for a project (*e.g.*, power flows that contribute to a reliability-driven upgrade).
  - The share of each region's projected or allocated usage of the interregional projects' transmission capability (*e.g.*, shares of increased flow-gate capacity).

Regions must explain their cost allocation framework through concrete (even if illustrative) examples that consider key variables, such as the size and type of project.

Payment mechanisms: Planning processes should specify the financial mechanisms that allow for the actual sharing of project investment costs or annual project revenue requirements across the regions' boundaries. We propose as a starting point the consideration of two types of payment mechanisms: (1) physical ownership shares; and (2) financial transfers. To facilitate the implementation of cost

[36] A FERC requirement that all transmission planning regions consider a similarly broad set of transmission-related benefits would reduce perception that unfair cost allocations result from regions' different scope of quantified benefits.

allocation mechanisms, we recommend that, to the extent feasible and practical, an entity sharing the cost of interregional projects should also receive physical or financial rights for a commensurate share of the project's added transmission capability (*e.g.*, financial transmission rights or a share of increased flow gate capability).

Cost allocation based on physical ownership shares can be implemented through either (1) physical ownership of individual project segments or (2) co-ownership of the interregional or individual project segments. In either case, ownership of individual project segments would be assigned so that the investment and operating cost of each owned portion of the project is consistent with the determined cost allocations. Co-ownership of interregional projects or individual project segments may be necessary where the project cannot be divided into fully-owned segments or if a proposed project or project segment is entirely within the service territory of only one of the regions. In other words, different shares of the interregional project would be allocated to existing or new transmission owners within each of the two regions. The transmission owners would then simply recover the cost of their portion of the project as they would recover the cost of any other regional or local transmission project.

If the interregional project is developed by a single corporate entity, the company could form a transmission-owning subsidiary in each of the neighboring regions, each of which would recover the costs associated with its ownership share of the interregional project through the respective existing regional or local cost recovery options.

Where ownership-based allocation of project costs is neither feasible nor practical, cost allocation can be implemented through financial transfers from one region to the other. These payments would correspond to the determined share of the interregional project's revenue requirements. The revenue requirements associated with payments to the neighboring regions would be recovered consistent with the cost recovery of the revenue requirements of local and regional projects in the transmission owner's regional footprint. We recommend that such payments be implemented in conjunction with the assignment of physical or financial rights for a commensurate share of the project's added transmission capability.

B. Key Stakeholder Action Items

To implement the suggested improvements to capture the full range of benefits in planning, we propose that transmission planners and policy makers take the following actions:

FERC:

- Establish new cost allocation minimum standards and procedures for regional planning authorities to implement
- Permit the development of innovative and flexible cost allocation approaches that align with those guidelines

- Confirm that reasonableness of cost allocation will be based where possible on benefits from a portfolio of transmission projects rather than based on the benefits of each individual project

Federal Policy Makers

- Consider federal funding or federal guidelines for cost allocation of interregional transmission projects

State Policymakers and Regulators

- Propose and support innovative, flexible, and portfolio-based cost allocation for interregional public policy projects

Regional Planning Authorities

- Work with neighboring regions to develop and implement better processes for interregional planning, including a cost allocation method that is sufficiently flexible and can be implemented in both regions

Transmission Owners

- Utilize regional stakeholder processes to advocate for more effective, innovative, flexible, and portfolio-based cost allocation mechanisms
- Empower stakeholders and consumers in developing a cost allocation approach

VI. Case Study of Successful Multi-Area Transmission Planning and Cost Allocation

The following case study, based on an earlier report on interregional planning and cost allocation prepared for the SPP Regional State Committee (and presented in Appendix C to this report), illustrates how the proposed improvements to the determination of interregional needs, the quantification of benefits, and the cost allocation mechanism can overcome existing barriers to yield valuable interregional transmission projects.

The Acadian Load Pocket (ALP) Project developed in 2009 addressed transmission needs along the seam between three separate transmission service providers in Louisiana. While not specifically an interregional project in nature, the challenges encountered in developing the ALP transmission project and the approach to cost allocation are helpful in informing the current efforts to develop a more robust interregional planning and cost allocation framework.

The ALP Project is a helpful case study because: (1) it is a seams project involving multiple transmission providers; (2) it provides both reliability and economic benefits to the sponsors; (3) the reliability and economic benefits differ significantly for each of the sponsors; (4) cost allocation was implemented by aligning its benefits through physical ownership of newly constructed facilities; (5) there was strong public utility commission involvement; and (6) the project has already been approved.

There are at least six important "lessons learned" from the ALP Project case study:

- **First**, there was general agreement that the various problems identified by the transmission service providers created a need that had to be addressed and that a seams solution could provide both individual and joint benefits.
- **Second**, it was recognized that needs and drivers were different for the parties involved. The ALP Project provided both reliability and economic benefits, which accrued to parties differently.
- **Third**, transmission planning and cost allocation was jointly considered so that a solution and its associated costs produced equitable results. Cost allocation was determined by considering the approximate magnitude of the reliability and economic benefits to each party involved, while also considering the geographic location of the future facilities and operational flexibility, rather than a strict formulaic matching of costs and benefits.
- **Fourth**, cost allocation via transmission ownership (not financial transfers) was easier to accomplish. Especially for non-market regions and utilities, financial transfers may not even be possible or prove difficult to implement. For the ALP Project, each entity shared costs by building, owning, and maintaining a different segment of the buildout.
- **Fifth**, each entity is responsible for recovering approved ALP Project-related costs through its own transmission tariff.
- **And finally**, participation by the Public Service Commission helped facilitate the process.

Appendix A: Barriers to Interregional Transmission

The Barriers to Interregional Transmission

A SURVEY OF POLICY MAKERS, REGULATORS, TRANSMISSION PLANNERS, TRANSMISSION DEVELOPERS, TRADE GROUPS, AND CUSTOMERS

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Brattle

Barriers Preventing Beneficial Interregional Transmission

Interregional transmission (between separately-operated regions of the grid) can provide large cost savings and reliability benefits

- Numerous studies have shown that **interregional transmission reduces costs, lowers electricity costs to customers, and reduces the risk of high-cost outcomes and power outages**
- These benefits of interregional transmission go beyond transporting clean energy to load. They also include resource and load diversification, reliability, and other wholesale power market benefits
- Yet, the benefits shown in many **studies have failed to yield any interregional transmission** projects for a variety of reasons

Barriers to the planning and development of interregional transmission prevent these benefits from being realized

A survey of policy makers, regulators, transmission planners, transmission developers, trade groups, and customers identified three categories of such barriers:

1. Insufficient **leadership, alignment, and understanding** on interregional matters yields little support for the development of interregional transmission projects
2. Narrow, overly-formulaic, and misaligned **planning processes and analyses** have limited the "needs" identified, benefits calculated, projects considered, and the design of acceptable cost allocations
3. Significant **regulatory constraints** have stifled development, including overly-prescriptive tariffs and state permitting processes

All stakeholders interviewed agree that interregional transmission barriers need to be addressed. We are now in the process of developing a detailed roadmap to address these barriers

The Need for and Benefits of Interregional Transmission

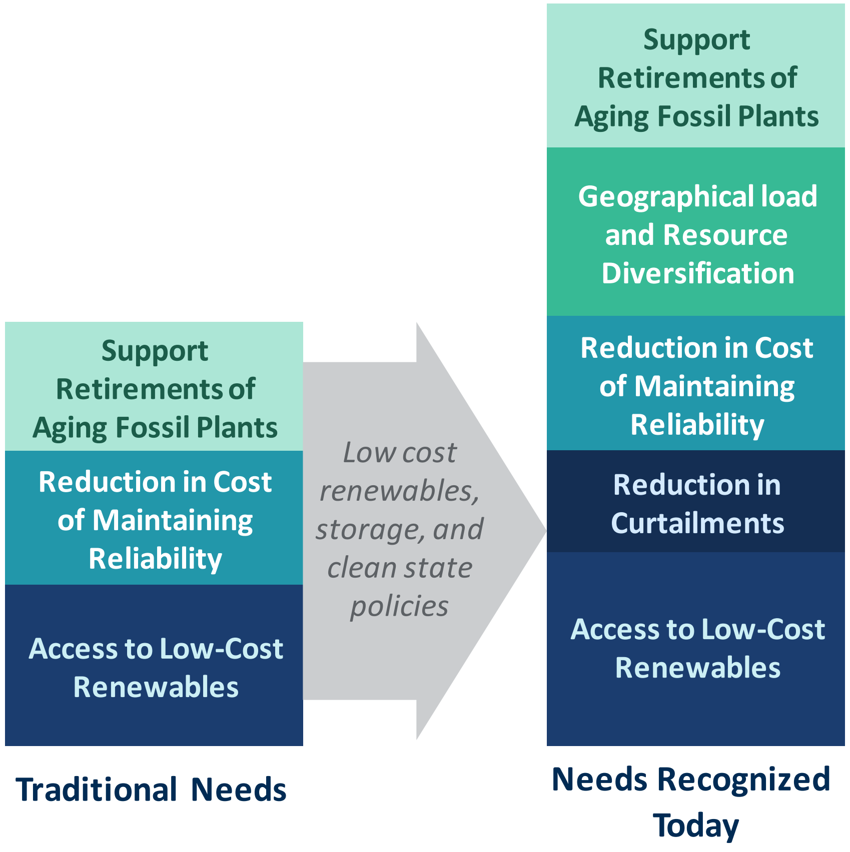
STUDIES SHOW LARGE BENEFITS BUT DO NOT RESULT IN NEW TRANSMISSION DEVELOPMENT

The Need for and Value Proposition of Interregional Transmission

Existing studies highlight how interregional transmission can provide significant benefits as the grid transitions to clean resources

- **The value proposition (increased reliability, reduced costs, risk mitigation) of interregional transmission defines the "need" for the approval these projects**
- In the last ten years, numerous studies have looked at a wide range of grid transition scenarios—including a "continuation of recent trend" view in which coal is gradually being replaced by renewables to reduce emissions
  - In all instances, **building new interregional transmission reduces overall system costs and reduces emissions** while reducing risk and helping to maintain or increase reliability
- The **need for interregional transmission has evolved** as renewable costs have declined and state clean-energy and decarbonization policies have become more ambitious. It has shifted from transporting (mostly) low-cost wind to load centers to include a broader set of benefits: **interregional transmission improves reliability and protects customers from high-cost outcomes**
- While there is some substitutability between solar, storage, and transmission, the **declining cost of solar and storage has not changed the conclusion that interregional transmission reduces costs**
- The development of **interregional transmission and lower electricity rates also create jobs**; potentially more than many local-only renewables policies
- Particularly as shares of weather-correlated renewable generation increases, **robust interregional transmission** is needed to ensure that the geographic scale of the grid exceeds **the size of typical weather systems**

Evolution of Transmission Needs



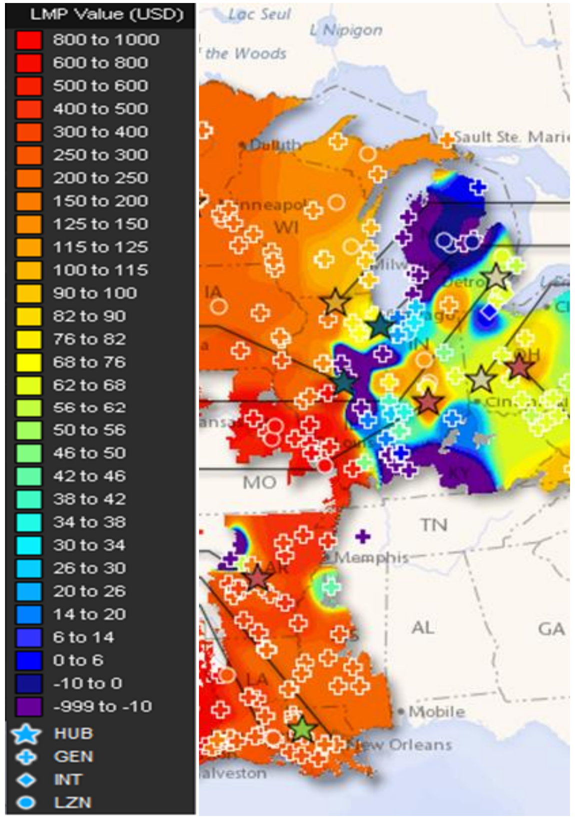
Summary of Recent Interregional Transmission Studies

Study	Region	Findings
NREL North American Renewable Integration Study (2021)	U.S., Canada, Mexico	• Increasing trade between countries can provide $10-30 billion in net benefits • **Interregional transmission expansion achieves up to $180 billion in net benefits**
MIT Value of Interregional Coordination (2021)	Nation-Wide	• National coordination of **reduces the cost of decarbonizing by almost 50% compared to no coordination between states** • The lowest-cost scenario builds almost 400 TW-km of transmission; including **roughly 100 TW-km of DC capacity between the interconnections** and over 200 TW-km of interregional AC capacity • **No individual state is better off implementing decarbonization alone** compared to national coordination of generation and transmission investment • Low storage and solar costs still result in significant cost effective interregional transmission
Princeton Net Zero America Study (2021)	Nation-Wide	• Achieving net-zero emissions by 2050 requires **700-1,400 TW-km of new transmission** • Investment in transmission needed ranges **$2-4 trillion dollars by 2050**
U.C. Berkeley 90% by 2035 (2020)	Nation-Wide	• The only national study that suggest relatively little interregional transmission would be needed to achieve 90% clean electricity. However, the study's simulation approach does not utilize more granular and well-established methods to properly value interregional transmission.
Vibrant Clean Energy Interconnection Study (2020)	Eastern Interconnect	• **40 to 90 TW-km of transmission is built by 2050** to meet climate goals • Transmission development can create **1-2 million jobs in the coming decades**, more than wind, storage, or distributed solar development • Transmission **reduces electricity bills by $60-90 per MWh**
Wind Energy Foundation Study (2018)	ERCOT, MISO, PJM, and SPP	• Transmission planners are not incorporating this rising tide of voluntary corporate renewable energy demand into plans to build new transmission
NREL Seams Study (2017)	Eastern and Western Interconnects	• Major new ties between interconnections **saves $4.5-$29 billion** over a 35 year period

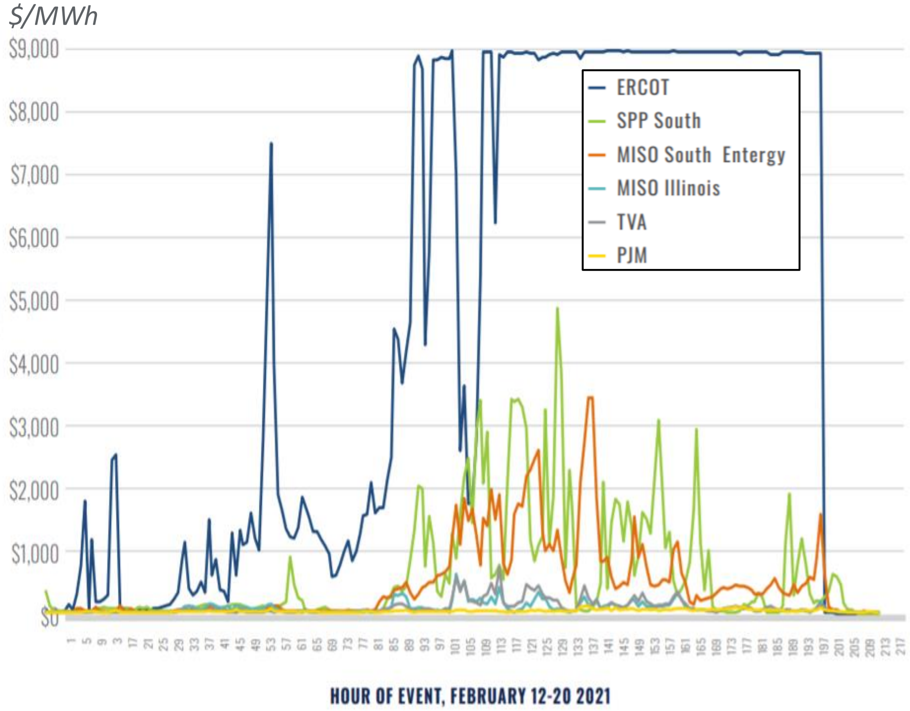
Case Study: Winter Storm Uri

Transmission constraints led to substantial price separations. An additional GW of transmission into Texas would have fully paid for itself over the course of the four-day event (Goggin, 2021).

LMPs on Feb 15th, 2021 at 7:45-7:55



Electricity Price Differences Between Regions During Uri



Savings per GW of Additional Interregional Transmission Capability
($ millions)

ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82

Limitations of Existing National Studies

Although existing studies demonstrate the cost reductions offered by interregional transmission, they have not been successful in motivating improved interregional planning or actual transmission project developments. The reasons include:

- Many studies **tend to analyze aspirational clean energy targets (e.g., 90% by 2035 or 100% by 2050)** not the actual policies and mandates applicable for the next 10-15 years
  - By not modeling actual state or federal policies, clean-energy mandates, and renewable technology preferences, the studies cannot demonstrate a compelling “need” to policy makers, regulators, and permitting agencies
- The studies are **not transmission planning studies** that produce specific transmission projects that can be developed to deliver the identified benefits and they do not support a need for specific projects
  - The results of these studies do not connect with RTO planning processes and needs identification,
  - The studies typically do not consider how to recover (“allocate”) transmission costs
- Studies **fail to identify how benefits and costs are distributed** across utility service areas, states, or RTO/ISO under different scenarios, as would be necessary to gain support and develop feasible cost recovery options
- There has not been **an analysis of the state-by-state economic impact and job creation** from interregional transmission development, reduced electricity prices, and shifts in the locations of clean-energy investment
- Most studies do not **propose actionable solutions** to address the many barriers to planning processes and to the development of new interregional transmission projects

National Studies are Not a Substitute for Transmission Planning

While national studies indicate the economic benefits of new regional and interregional transmission, they do not analyze the transmission grid in sufficient detail to yield actionable interregional transmission plans (and cannot substitute for interregional transmission planning)

- Various "macro grid" studies show how much transmission capacity might be cost effective between certain regions, but they fail to:
  - Consider existing **transmission planning criteria** (e.g., reliability, stability, size of largest contingencies)
  - Pinpoint **specific locations on the power system** where transmission projects could interconnect to achieve cost reductions (studies typically only indicate which regions would benefit from more transfer capacity)
  - **Identify a list of actionable individual transmission projects (or manageable portfolios of projects)** and quantify project-specific benefits needed by regional planning authorities and transmission developers to obtain approvals for individual projects
  - **"Connect" to RTO/ISO and TO planning processes** that can approve actual projects for development
  - **Consider actual project costs and cost allocations** (including the costs of necessary local upgrades)

Detailed interregional transmission studies that include RTOs/ISOs are needed to identify specific projects that meet all planning criteria and are cost-effective overall and to the individual regions

Regional Studies do Not Adequately Consider Interregional Needs

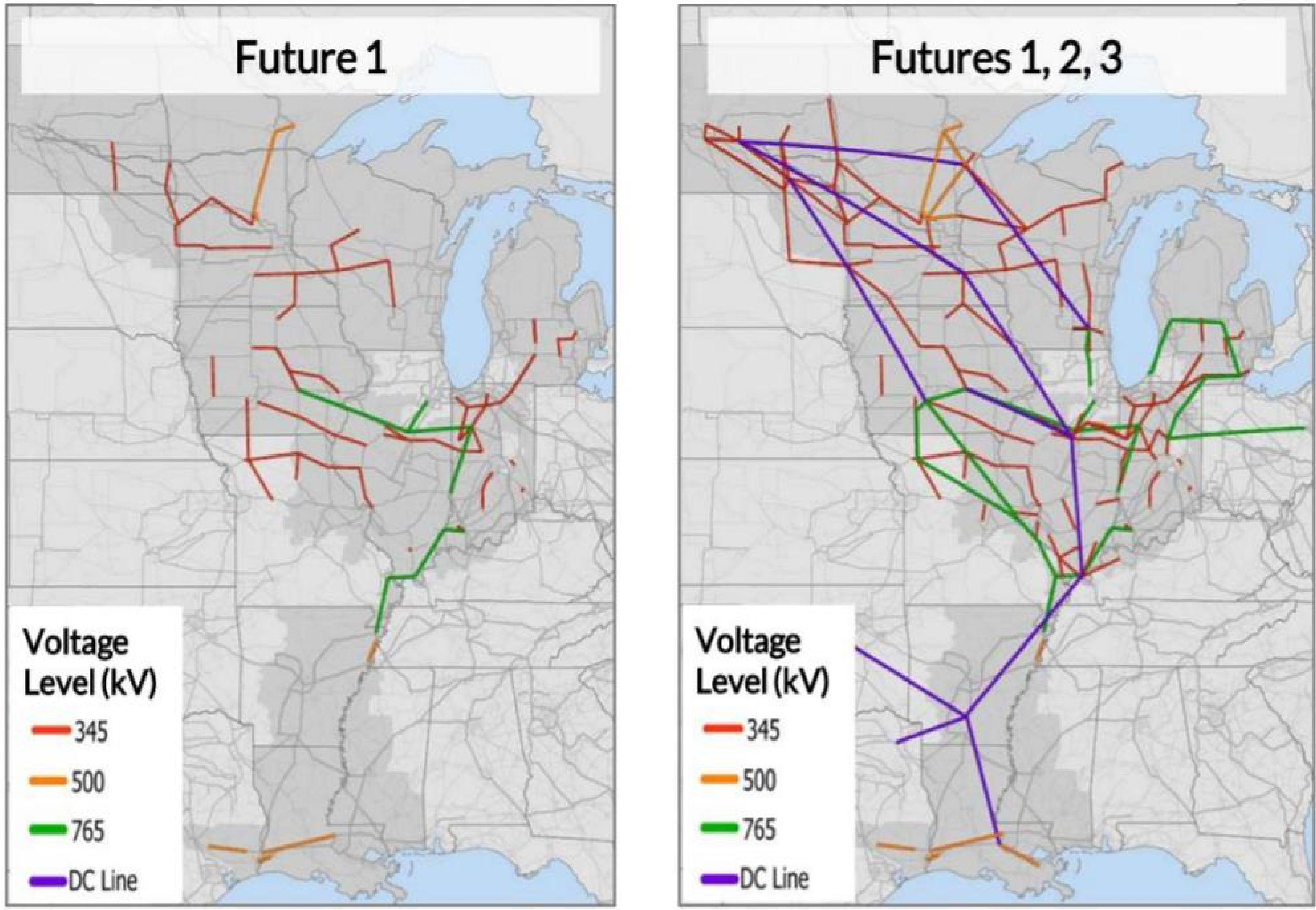
Example: MISO's new Renewable Integration Impact Assessment (RIIA) improves regional planning (over most similar efforts) by:

- Establishing the need to proactively study policy goals and reliability goals simultaneously
- Considering multiple economic benefits across a diverse set future scenarios

However, the study does not meaningfully address interregional opportunities:

- Despite modeling five regions in addition to MISO, the study did not adequately consider interregional transmission (see figures)
- Recommends a "least-regret" transmission plan, which is not the "optimal" transmission plan (and does not address possibility of regrets from inadequate transmission)
- Even if "optimal" for MISO, it's likely far from optimal for the broader regional grid

MISO's projected scope of transmission expansion needs



Source: MISO LRTP Roadmap, March 2021.

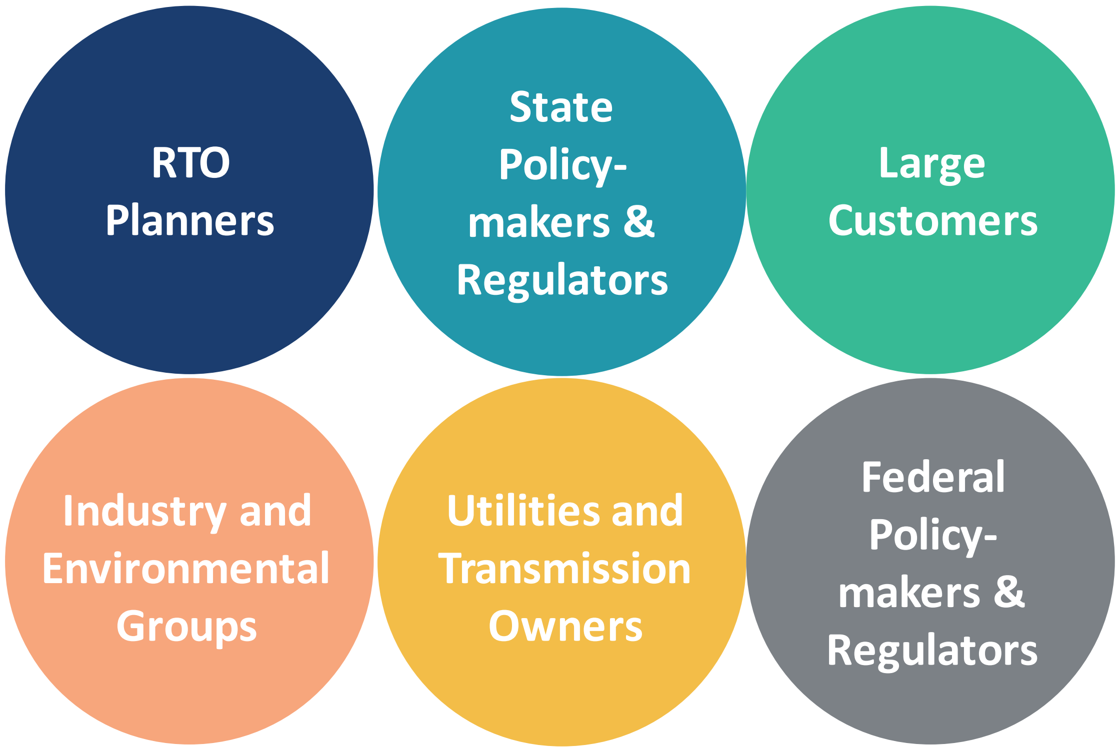
Stakeholder Perspectives on Barriers to Interregional Transmission

A SURVEY OF POLICY MAKERS, REGULATORS, TRANSMISSION PLANNERS, TRANSMISSION DEVELOPERS, INDUSTRY AND ENVIRONMENTAL GROUPS, AND CUSTOMERS

Stakeholder Survey on Interregional Transmission

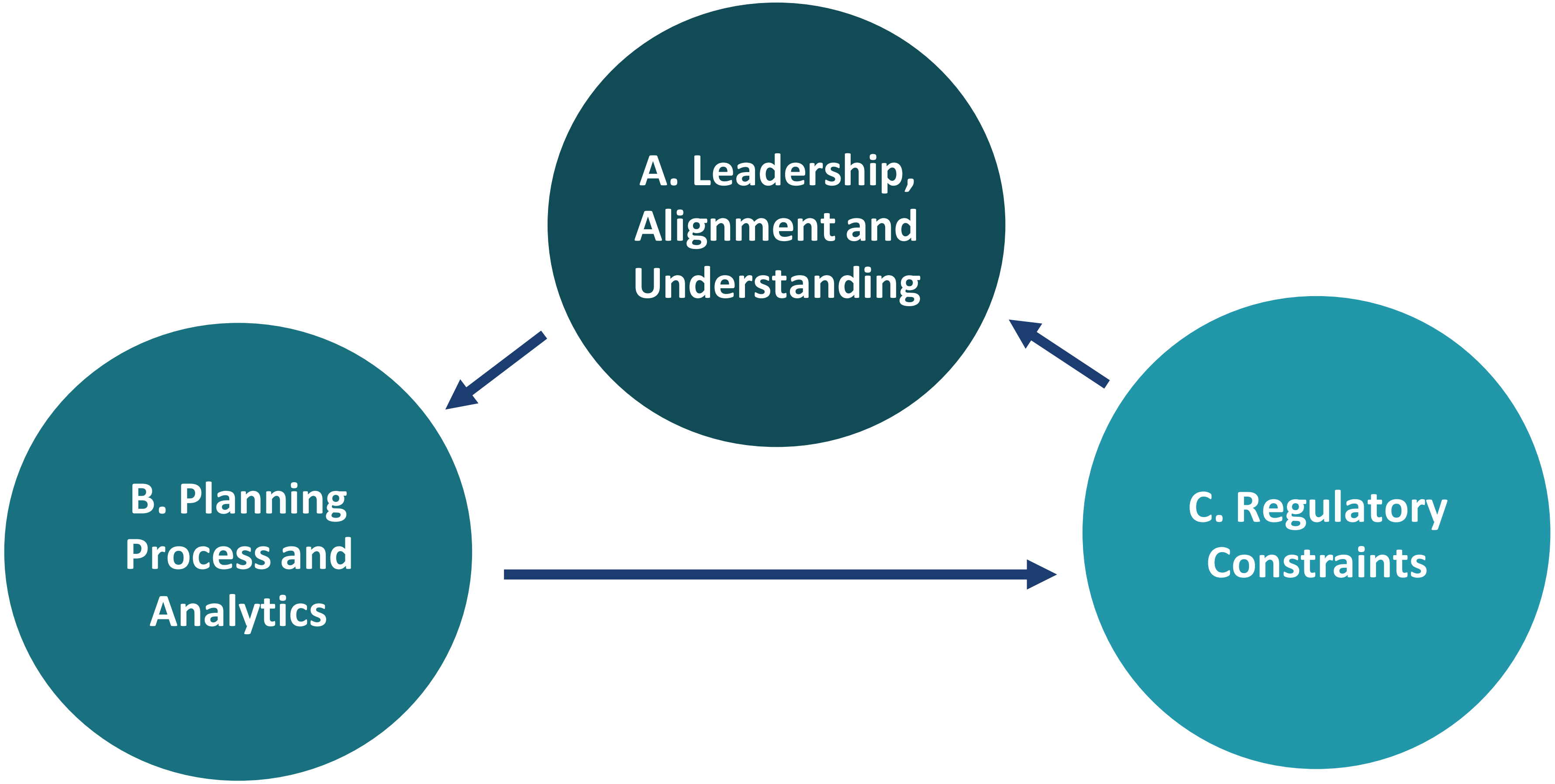
- We surveyed stakeholders from **18 different organizations** across in the industry on their views about interregional transmission planning
- Topics covered in the interviews included:
  - **Benefits of Interregional Projects:** What are the primary benefits or interregional projects to your region? What are the risks of investments or insufficient investments in interregional projects?
  - **Barriers to Interregional Planning:** What are the primary barriers to realizing planning? Are some of these barriers specific to the individual RTOs and seams?
  - **Potential Solutions for Interregional Planning**: What should be done to make interregional planning more effective? To what extent are effective improvements broadly applicable or specific to the individual RTOs and seams?
- See slides 19-20 for a summary of stakeholder comments

Stakeholder Groups Interviewed



Three Categories of Interregional Transmission Barriers

The stakeholders (ranging from RTOs, industry, trade groups, regulators, customers, to policy makers) consistently identified barriers to interregional transmission planning and project development that fall into three interrelated categories:



Identified Barriers to Interregional Transmission

A. Leadership, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policy makers to prioritize interregional planning 2. Limited trust amongst states, RTOs, utilities, & customers 3. Limited understanding of transmission issues, benefits & proposed solutions 4. Misaligned interests of RTOs, TOs, generators & policymakers 5. States prioritize local interests, such as development of in-state renewables
B. Planning Process and Analytics	6. Benefit analyses are too narrow, and often not consistent between regions 7. Lack of proactive planning for a full range of future scenarios 8. Sequencing of local, regional, and interregional planning 9. Cost allocation (too contentious or overly formulaic)
C. Regulatory Constraints	10. Overly-prescriptive tariffs and joint operating agreements 11. State need certification, permitting, and siting

A. Leadership, Alignment, and Understanding

1. **Lack of aligned leadership from federal, state & RTO policy makers**
   - FERC:
     - Interregional planning neither required nor prioritized
     - No effort to identify and share industry best practices
     - Some RTOs constrained by overly-specific FERC tariffs
   - States:
     - Limited involvement in RTO planning to date
     - Demands for better planning lack specificity
     - States prioritize local issues above regional needs
   - RTOs:
     - Interregional planning has not been a priority, often due to of a lack of federal and state policy direction
     - Focused instead on reliability projects
2. **Mistrust amongst states, RTOs & utilities**
   - States and customers concerned that utilities and RTOs have their interests in mind
   - Even engaged states often have limited influence into RTO processes
3. **Limited understanding of transmission issues, benefits, and proposed solutions**
   - Limited communication across key players
   - Benefits perceived to be uncertain, changing, intangible; cost/risk of insufficient transmission not well appreciated
   - States have limited technical capabilities and resources to engage in RTO processes
   - Perceived limited benefits from rising transmission costs results in rate-increase fatigue
   - Few opportunities to educate stakeholders on analyses
4. **Misaligned interests of RTOs, TOs, generators, and policymakers**
   - Generation vs transmission concerns
   - Competitive transmission and cost sharing
   - Perception of winners and losers from price effects of transmission
5. **State preference for local renewables**
   - Focus on in-state resources to meet clean energy goals

B. Planning Process and Analytics

6. Benefit analysis too narrow

- Silo-ed planning with narrow set of benefit metrics; no opportunity for interregional multi-value projects
- Limited experience with quantifying a broader range of benefits results in inability to demonstrate "needs"
- Regions consider different scopes of benefits
- Scope of RTO analyses limited only to their footprint (which cannot identify valuable projects with interregional benefits)
- RTO coordination challenges reduce the scope of benefits and future scenarios considered (even below the limited scope of regional analyses)

7. Lack of proactive planning for a full range of future scenarios

- Over-emphasis on base case (and business as usual) scenarios
- Too focused on near-term outlook and needs
- Does not adequately cover sufficiently wide range of future market conditions (to capture risk-mitigation and option value of transmission)

8. Sequencing of local, regional, and interregional planning

- Challenges to fit interregional planning into sequencing of regional planning, generation interconnection requests, transmission service requests, and local transmission needs
- Makes it difficult to identify more valuable interregional solutions that also address reliability needs in a timely manner

9. Contentious cost allocation

- No pre-determined cost allocation or no flexibility to consider a wider set of benefits and solutions
- Cost allocation considered too early; should look at total benefits of individual projects first
- Project-by-project allocations more contentious than portfolio-based allocations (with more stable and widely-distributed benefits)
- False precision of formulaic approaches does not align costs with wide range of changing benefits

C. Regulatory Constraints

10. Overly-prescriptive tariffs and joint operating agreements

- Some RTOs feel constrained by their prescriptive FERC tariff and JOAs that limit a broader view of interregional planning
- Interregional planning processes are too narrow and disconnected between regions to establish compelling needs (different benefits analyzed by each region and no consideration of benefits from other regions in project approval)
- Planning processes often do not consider interregional solutions to address reliability needs on a timely manner
- Results in “lowest-common denominator” approach to interregional planning

11. State need certification, permitting, and siting

- Multi-state projects must receive approvals from each state (often based on different standards of project “need”)
- State regulators and policymakers often do not fully recognize the complete range of benefits to their state from interstate transmission (economic stimulus and development, reduced power prices, lowest-cost achievement of state public policy goals, meeting customers’ clean energy preferences)

Interregional Barriers Identified by Interviewed Stakeholders

Barrier	RTO Planners	State Policymakers & Regulators	Large Customers	Industry & Environmental Groups	Federal Policymakers & Regulators	Utilities & Transmission Owners
1. Lack of aligned leadership		✓	✓	✓	✓	✓
2. Mistrust among players		✓	✓		✓	✓
3. Limited understanding	✓	✓	✓	✓		✓
4. Misaligned interests	✓	✓	✓	✓		✓
5. State local preferences	✓	✓	✓	✓	✓	✓
6. Benefits analysis to narrow	✓	✓	✓	✓	✓	✓
7. Lack of proactive planning				✓	✓	✓
8. Planning sequence	✓			✓	✓	✓
9. Cost allocation	✓	✓		✓	✓	✓
10. Tariffs and JOAs	✓			✓		
11. State needs, siting, permitting	✓			✓	✓	

Next Steps: Addressing the Identified Barriers

To improve interregional transmission planning and project development will require a coordinated effort by industry stakeholders to address each of the identified barriers

– To align **leadership**, build **alignment**, and improve **understanding** of the complex set of barriers and transmission-related benefits will require a coordinated outreach to federal and state policy makers by a group of stakeholders that represent a broad range of interests and perspectives

– Improving RTO **planning processes and analyses** will require implementing already-available industry experience and best practices to quantify a broad range of transmission-related benefits, consider a wider range of scenarios, and improve the sequencing of regional and interregional planning processes

– Addressing the identified **regulatory constraints** will require evaluating and updating RTO tariffs and agreements, federal regulatory policies, and transmission-related state policies to improve planning, cost-allocation, and permitting processes

We are now in the process of developing a detailed roadmap to address these barriers

Summary of Responses by Stakeholder Group

Reports on Transmission Planning

Stakeholder Feedback by Stakeholder Type

Stakeholders	Key Points
RTO Planners	• Lack of consensus on benefits; need to expand benefits, including from capacity savings; take a total cost approach • Limited by overly prescriptive tariffs and JOAs that specify planning process; utility interests are a major barrier • Better to take the view of solving problems than to analyze limited scope of benefits • Expand view of benefits to both customers *and* generators • A single interregional planning entity would be better than joint planning • Already model other systems; should plan for upgrades across a wider footprint and bring ideas to the table • Need increased state involvement and align interests/objectives; states need education on transmission issues/benefits; MGA letter not actionable • Need to communicate to states the value of a mix of local resources and out-of-state resources in terms of economic impacts • Lack coordination between regional and interregional planning; sequencing of planning is a challenge • Customers tired of spending on transmission; utilities are not in a strong position to push for more investment • Not clear that federal policy changes will resolve issues • Get RTO CEOs together to prioritize these issues, come to consensus on best approaches
State Policymakers & Regulators	• Significant trust issue between states, utilities, and RTOs; lack confidence that RTOs and utilities have their interests in mind • Costs rising without clear benefits to customers; utilities and RTOs just want more infrastructure, need to be more forthcoming • States lack resources to participate in technical analysis, but "can't be passive any longer" • Transmission planning seen as a complex process with unclear benefits to customers • Need RTOs and utilities meeting with state Governor offices to open lines of communications on key issues, benefits of transmission, and potential downside of focusing only on in-state resources • Challenging to get states to commit to future goals and resources; uncertainty in future resources is a barrier; • Lack awareness of what has worked in other regions in terms of benefits considered, look-back analysis of benefits • Don't want FERC to be heavy handed, instead should be a mediator/enabler between parties • Hopeful that recent changes in RTO processes will result in better outcome • Cost allocation process is too contentious, especially when there are inequities in benefits for several stakeholders and for portfolio projects
Large Customers	• Shifting to a more local/regional view of renewable energy, especially to meet sustainability or clean energy targets • Benefits of increased transmission are pretty obvious to them for reducing costs of clean energy resources and providing option value • Trust between utilities and customers has eroded, customers want to rebuild with more engagement and data transparency • Need leadership to get out of the current planning paradigm; could come from FERC or RTO boards • Meeting with RTO board members to identify key issues and need to drive change • RTOs lack the authority to do the right planning; cost allocation, siting, and permitting remain a key barriers • States need to understand tradeoff of transmission vs generation costs; and risks of not building out the system

Summary of Stakeholder Feedback

Stakeholders	Key Points
Industry & Environmental Groups	• Limited view of benefits; highlight to stakeholders that a lot of cost effective transmission is being left on the table • Find high-value, small interregional projects to use as examples • RTOs timid in projecting new resources; not comfortable adding non-firm resources; need to use more scenario analysis • FERC is pretty limited in its ability to impose additional requirements on RTOs • Hope new FERC will prioritize Tx planning, impose more requirements for planning, and resolve cost allocation • Getting state policymakers on board is crucial; need to shift conversation away from wind imports towards value of exports • RTOs plan for their internal benefits, modify projects to maximize their benefits; creates DMZ between RTOs • Waiting to see what comes out of new approach by RTOs in terms of benefits and identifying solutions
Federal Policymakers & Regulators	• Limited by lack of national energy policy, FERC backstop siting, antiquated Federal Power Act; NERC may be pathway to create reliability need for interregional transmissions, but uncertain how effective and expedited that process can be • Federalism isn't working here; won't work if states can veto projects • Focused on reviewing and building on existing interregional processes • Expect FERC to review Order 1000; can tweaks tariffs to allow for broader view of benefits • Utilities have overbuilt their local system and increased transmission costs • RTOs are showing limited leadership in resolving issues • States may need to develop their own transmission planning body to identify policy needs
Utilities and Transmission Owners	• States are focused on local resources and clean jobs; need to re-frame benefits for the states; make it a win for states • Thinking too small; different projects will result if you remove RTO borders from studies; but macrogrids don't get us anywhere • Limited scope of benefits; interregional benefits too diffuse and considered uncertain; make benefits more tangible • Hard to get consensus across RTOs when they use different models, assumptions, and benefits • FERC should be more prescriptive, require interregional planning, share best practices • Most customers primarily concerned about increasing transmission rates • Identify and communicate smaller-scale and highly beneficial interregional projects to get the ball rolling • Federal backstop siting worked for gas pipelines, could it work for electric transmission? • Need to think about what is in it for local utilities, otherwise they will remain a barrier • Utilities need to do more to sell benefits of transmission to PUCs and customers • Cost allocation remains a key barrier; should consider cost allocation of a portfolio of projects instead of project-by-project

Brattle Group Reports on Transmission Planning

Well-Planned Electric Transmission Saves Customer Costs:
Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future

Link: https://bit.ly/3dnKrxe

PREPARED FOR

WIRES

PREPARED BY

Judy W. Chang

Johannes P. Pfeifenberger

May 2016

THE Brattle GROUP

Toward More Effective Transmission Planning:
Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid

PREPARED FOR

WIRES

PREPARED BY

Johannes P. Pfeifenberger

Judy W. Chang

Akarsh Sheilendranath

April 2015

Link: https://bit.ly/2GU4h7w

The Brattle Group

Link: https://bit.ly/3jS0PsB

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

July 2013

Judy W. Chang

Johannes P. Pfeifenberger

J. Michael Hagerty

Link: https://bit.ly/2KaFLAk

BU

Boston University Institute for Sustainable Energy

The Value of Diversifying Uncertain Renewable Generation through the Transmission System

September • 2020

Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

Link: Brattle Grid Strategies

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OCTOBER 2021

Brattle

GRID STRATEGIES LLC

Documents proven approaches to quantifying various benefits

Additional Reading on Transmission

Pfeifenberger et al, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, Brattle-Grid Strategies, October 2021.

Pfeifenberger, Transmission Options for Offshore Wind Generation, NYSERDA webinar, May 12, 2021.

Pfeifenberger, Transmission Planning and Benefit-Cost Analyses, presentation to FERC Staff, April 29, 2021.

Pfeifenberger et al, Initial Report on the New York Power Grid Study, prepared for NYPSC, January 19, 2021.

Pfeifenberger, "Transmission Cost Allocation: Principles, Methodologies, and Recommendations," prepared for OMS, Nov 16, 2020.

Pfeifenberger, Ruiz, Van Horn, "The Value of Diversifying Uncertain Renewable Generation through the Transmission System," BU-ISE, October 14, 2020.

Pfeifenberger, Newell, Graf and Spokas, "Offshore Wind Transmission: An Analysis of Options for New York", prepared for Anbaric, August 2020.

Pfeifenberger, Newell, and Graf, "Offshore Transmission in New England: The Benefits of a Better-Planned Grid," prepared for Anbaric, May 2020.

Tsuchida and Ruiz, "Innovation in Transmission Operation with Advanced Technologies," T&D World, December 19, 2019.

Pfeifenberger, "Cost Savings Offered by Competition in Electric Transmission," Power Markets Today Webinar, December 11, 2019.

Pfeifenberger, "Improving Transmission Planning: Benefits, Risks, and Cost Allocation," MGA-OMS Ninth Annual Transmission Summit, Nov 6, 2019.

Chang, Pfeifenberger, Sheilendranath, Hagerty, Levin, and Jiang, "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value," April 2019. "Response to Concentric Energy Advisors' Report on Competitive Transmission," August 2019.

Ruiz, "Transmission Topology Optimization: Application in Operations, Markets, and Planning Decision Making," May 2019.

Chang and Pfeifenberger, "Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future," WIRES and The Brattle Group, June 2016.

Newell et al. "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," on behalf of NYISO and DPS Staff, September 15, 2015.

Pfeifenberger, Chang, and Sheilendranath, "Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid," WIRES and The Brattle Group, April 2015.

Chang, Pfeifenberger, Hagerty, "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," on behalf of WIRES, July 2013.

Chang, Pfeifenberger, Newell, Tsuchida, Hagerty, "Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process," October 2013.

Pfeifenberger and Hou, "Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning," on behalf of SPP, April 2012.

Pfeifenberger, Hou, "Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada," on behalf of WIRES, May 2011.

Appendix B: Studies Documenting the Benefits of Interregional Transmission

Numerous studies of the future resource mix find that large amounts of power must be able to move back and forth across regions, and interregional transmission expansion is needed for this to happen. This evidence includes:

- A study by leading grid experts at the National Oceanic and Atmospheric Administration (NOAA) found that moving away from a regionally divided network to a national network of HVDC transmission can save consumers up to $47 billion annually while integrating 523 GWs of wind and 371 GWs of solar onto the grid.[37]
- The NREL Interconnections Seam Study shows that significant transmission expansion and the creation of a national network will be essential in incorporating high levels of renewable resources, all the while returning more than $2.50 for every dollar invested.[38] The study found a need for 40–60 million MW-miles of alternating current (AC) and up to 63 million MW-miles of direct current (DC) transmission for one scenario. The U.S. has approximately 150 million MW-miles in operation today.
- A study by MIT scientists found that inter-state coordination and transmission expansion reduces the cost of zero-carbon electricity by up to 46% compared to a state-by-state approach.[39] To achieve these cost reductions the study found a need for approximately doubling transmission capacity, and "[e]ven in the ''5× transmission cost'' case there are substantial transmission additions."[40]
- A study by Vibrant Clean Energy found that lower storage costs (and to some extent lower solar costs) reduce the optimal amount of transmission investments, but even studies with very low storage and solar costs find that it is cost effective to add significant new interregional transmission.[41] Moreover, storage raises utilization of interregional transmission lines, using the lines during low-renewable production hours.
- Dr. Paul Joskow of MIT has reviewed transmission planning needs and concluded that "[s]ubstantial investment in new transmission capacity will be needed to allow wind and solar generators to develop projects where the most attractive natural wind and solar resources are located. Barriers to

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37 Alexander E. MacDonald, *et al.*, *Future Cost-Competitive Electricity Systems and Their Impact on U.S. CO2 Emissions*, Nature Climate Change 6, at 526–531, January 25, 2016.

38 Aaron Bloom, *Interconnections Seam Study*, August 2018.

39 P. R. Brown and A. Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule, December 11, 2020.

40 *Id.*, at 12.

41 Clack, C., *et al.*, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, Vibrant Clean Energy, October 2020

expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[42]

- The Princeton University Net Zero America study of a low carbon economy found "[h]igh voltage transmission capacity expands ~60% by 2030 and triples through 2050 to connect wind and solar facilities to demand; total capital invested in transmission is $360 billion through 2030 and $2.4 trillion by 2050."[43]
- A recent study to compare the "flexibility cost-benefits of geographic aggregation, renewable overgeneration, storage, and flexible electric vehicle charging," as "pathways to a fully renewable electricity system" found that "[g]eographic aggregation provides the largest flexibility benefit with ~5–50% cost savings.[44] The study found that "With a major expansion of long-distance transmission interconnection to smooth renewable energy variation across the continent, curtailment falls to negligible levels at a 60% renewable penetration, from 5% in the case without transmission. In the 80% renewable case, transmission reduced curtailment from 12% to 5%.[45]
- The Brattle Group analysts, on behalf of WIRES, demonstrate that transmission expansion creates trading opportunities across existing regional and interregional constraints. The report finds, using existing wholesale power price differences between SPP and the Northwestern U.S., that "adding 1,000 MW of transmission capability would create approximately $3 billion in economic benefits on a present value basis."[46]
- In its HVDC Network Concept study, MISO estimates that expanding east-to-west and north-to-south transmission interties can generate investment cost savings of approximately $38 billion through load diversity benefits that would reduce nation-wide generation capacity needs by 36,000 MW.[47]
- A study prepared for the Eastern Interconnection States Planning Council, National Association of Regulatory Utility Commissioners, and the Department of Energy estimates that $50–110 billion of interregional transmission will be needed over the next 20 years to cost-effectively support new generation investment. A co-optimized, anticipatory transmission planning process is estimated to reduce total generation costs by $150 billion, compared to a traditional transmission planning approach, and would generate approximately $90 billion in overall system-wide savings.[48]

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[42] Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1–3, January 15, 2020. See also Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

[43] Eric Larson, *et al.*, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, at 77, December 15, 2020.

[44] B. A. Frew, *et al.*, *Flexibility Mechanisms and Pathways to a Highly Renewable U.S. Electricity Future*, Energy, Volume 101, at 65–78, April 15, 2016.

[45] *Ibid*.

[46] Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, at 16, June 2016.

[47] MISO, *HVDC Network Concept*, at 3, January 7, 2014.

[48] A. Liu, *et al.*, *Co-optimization of Transmission and Other Supply Resources*, September 2013.

- A study conducted by the Eastern Interconnection Planning Collaborative on the need for interregional transmission projects to meet national environmental goals found that an efficient interregional transmission planning approach to meet a 25% nation-wide RPS standard would reduce generation costs by $163–$197 billion compared to traditional planning approaches.[49]
- Phase 2 of the Eastern Interconnection Planning Collaborative study found that the transmission investment necessary to support the generation and the environmental compliance scenarios associated with these savings ranges from $67 to $98 billion.[50] These results indicate that the combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to $100 billion.
- Recent experience in Germany shows that as renewable generation shares increase, the need for additional interregional transmission to help diversify renewable generation patterns increases as well. Germany recently approved a fourth major new transmission line interconnection to more completely and cost-effectively integrate its southern region (with surplus distributed solar generation during sunny days and import needs when the sun is down) and its norther region (with surplus offshore wind generation during wind-rich periods and import needs during low-wind periods).

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[49] Eastern Interconnection Planning Collaborative, *Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis*, December 2011.

[50] Eastern Interconnection Planning Collaborative, *Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios and Gas-Electric System Interface Study*, June 2, 2015.

Appendix C: Case Study of Multi-Area Transmission Planning and Cost Allocation

Case Study: The Acadiana Load Pocket Project

To help develop a cost allocation framework for SPP's Regional State Committee in 2012,[51] we reviewed SPP's prior experience with a "seams project"—the Acadiana Load Pocket ("ALP") Project. This Appendix C is taken from pages 34-41 of the SPP RSC report. Additional discussions of the ALP Project and other interregional transmission planning and cost allocation case studies are presented in Section XII of the SPP RSC report.

The approximately $200 million ALP Project is a series of new transmission lines and substations jointly developed by three transmission system operators—Cleco Power ("Cleco"), Lafayette Utilities System ("LUS"), and Entergy Gulf States Louisiana ("EGSL")—to address a variety of reliability and economic considerations related to serving a load pocket in south-central Louisiana.

While the ALP Project does not involve RTO seams, it specifically addresses transmission needs along the seam between three individual transmission service providers. The challenges encountered in developing the project and the associated cost allocation proved to be helpful in our effort to develop the proposed interregional planning and cost allocation framework. Specifically, the ALP Project is a helpful case study because: (1) it is a seams project involving multiple transmission providers; (2) it provides both reliability and economic benefits to the sponsors; (3) the reliability and economic benefits differ significantly for each of the sponsors; (4) cost allocation was implemented by aligning it with physical ownership of newly constructed facilities; (5) there was strong public utility commission involvement; and (6) the project has already been approved.

The ALP is defined as the electrical loads south of U.S. Highway 190 to the Gulf of Mexico, west of the Atchafalaya Basin, and east of the City of Jennings as shown in Figure C-1 below.[52] The loads within the ALP area include Cleco, LUS, EGSL, South Louisiana Electric Cooperative Association, South Louisiana

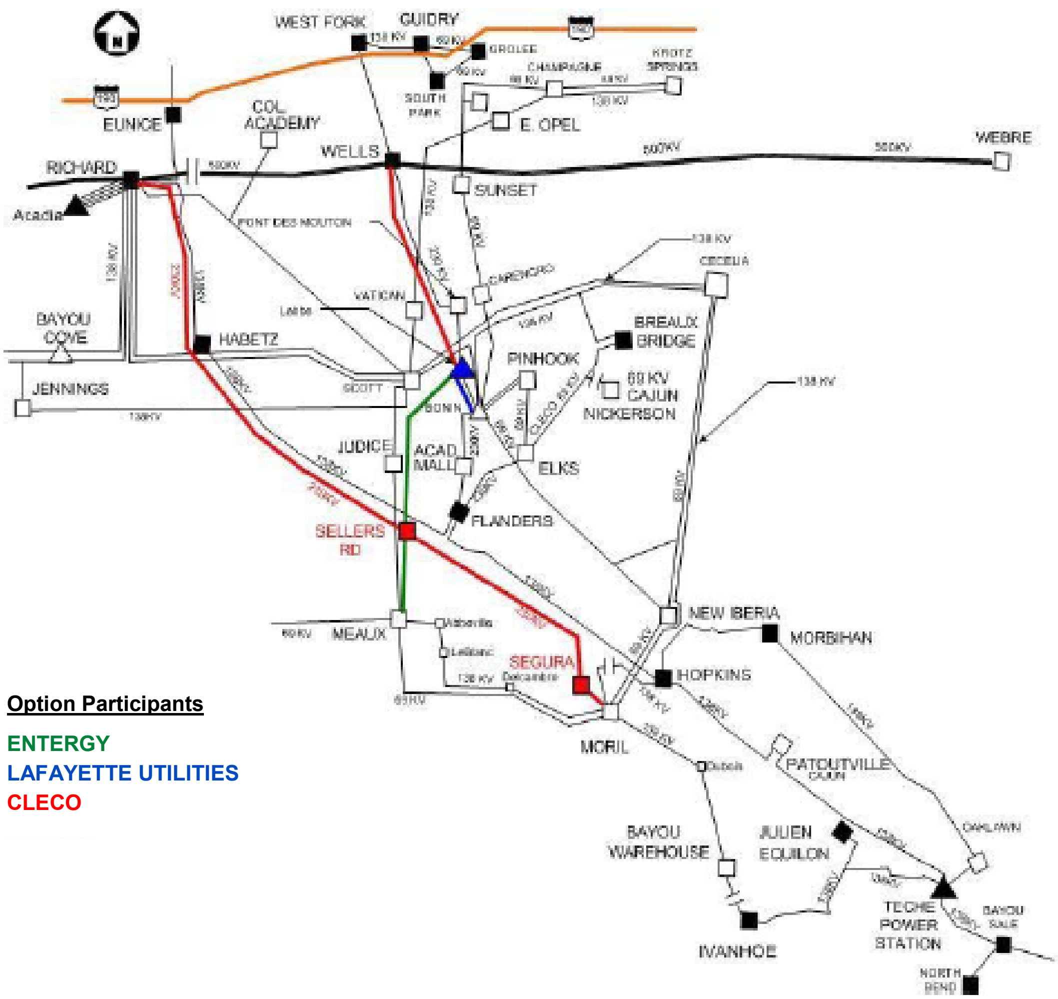
[51] Pfeifenberger and Hou, Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning, prepared for SPP Regional State Committee, April 2012 (SPP RSC report).

[52] Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008, p. 4 ("Whitmore Testimony, 7/14/08").

Electric Membership Corporation, and Louisiana Energy and Power Authority.[53] In 2008, load was approximately 1,700 MW while total generation capacity was only 965 MW.[54]

The ALP region had been experiencing several problems, including an increase in transmission loading relief ("TLR") procedures to curtail non-firm service, an over-reliance on inefficient generating units needed for voltage support, disconnects between modeling assumptions and actual operational limits, a lack of operational flexibility in the load pocket, and limitations to accommodate additional transmission service.

FIGURE C-1. ACADIANA LOAD POCKET PROJECT



Sources and notes: Southwest Power Pool, Inc., "Cleco, Entergy, and Lafayette Utilities System to improve electric service in South Louisiana through joint transmission project," January 19, 2009.

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53 *Ibid.*, p. 4.

54 *Ibid.*, Exhibit TJW-2, p 1 and p. 5.

The ALP area had been experiencing reliability problems since the early 2000s and a new substation was completed in 2005 to alleviate some of the TLR procedures that forced the curtailment of non-firm transmission service and relied on more expensive generation within the load pocket.[55] Despite the new substation, conditions within ALP continued to worsen and a joint study effort, including SPP as the Independent Coordinator of Transmission ("ICT") for Entergy, identified the following major issues within the ALP:

- **Increase in TLR procedures and their severity** — Between November 2006 and November 2007, SPP reliability coordinators initiated 125 TLR procedures, primarily on EGSL's lines for the loss of Cleco's or LUS's lines. The TLR procedures included both firm and non-firm curtailments for importing energy from external generators and required re-dispatch of Cleco's Teche and LUS's Bonin Power plants (discussed below).[56]
- **Over-reliance on inefficient units** — Because of import constraints, two plants within ALP, Cleco's Teche Power plant and LUS's Bonin Power plant, were required to be online during moderate to high load conditions.[57] The Teche plants are described as "old, less efficient steam turbines" with units 1, 2, and 3 placed in service in 1953, 1956, and 1971, respectively.[58] Cleco's Teche Unit 3 is the **single largest generation contingency** in ALP[59] and provides both **load-serving capability** and **voltage support,** which may complicate any scheduled maintenance and cause reliability concerns if the unit was to be offline for an extended period of time.[60] If a solution such as the ALP Project was implemented, estimated fuel savings to Cleco would be $144.2 million between 2010 and 2016 and $905.6 million between 2010 and 2039.[61] LUS may also realize economic benefits such as fuel cost savings and increased generation flexibility.[62]
- **Disconnects between planning model assumptions and operation**—
  - Long-term modeling of flows versus operational realities — In the long-term model, only firm network resources were dispatched and confirmed long-term firm transmission transactions are modeled to meet each control area's load. However, the increase in more efficient merchant generation with short-term economic power sales causes a deviation in modeled power flows and actual use of the transmission system.[63] The result

55 Whitmore Testimony, 7/14/08, p. 7 and p. 11.

56 *Ibid.*, p. 12.

57 *Ibid.*, p. 10.

58 *Ibid.,* p. 5.

59 *Ibid.,* p. 10.

60 *Ibid.,* p. 13.

61 *Ibid.,* p. 25.

62 *Ibid.,* p. 19.

63 Whitmore Testimony, 7/14/08*,* p. 7.

was that the long-term model did not accurately capture how heavily the transmission system was being used to import into ALP.
  - Natural gas prices — Unforeseen increases in natural gas prices caused economic dispatch to favor imported energy, putting stress on the existing transmission system which was not designed for such significant reliance on imports.[64]
  - Power flow model correction — A smaller conductor used to expeditiously replace lines damaged by Hurricane Lili in 2002 was incorrectly recorded in the power flow model and caused a fault, forcing lines out of service.[65]
- **Lack of operational flexibility** — Increased reliance on imports means that it was more difficult to obtain scheduled outages on the transmission system to perform routine maintenance.[66]

In 2008, a joint study facilitated by SPP identified several upgrade options, one of which was the ALP Project, comprised of a reliability component to address TLRs and related concerns and an additional economic component as shown in Table C-1 below.

While the reliability component addressed historical and current reliability concerns, the economic component was deemed valuable to the parties to create optionality by allowing the removal of must-run status for older units and increased operational flexibility.

[64] *Ibid.,* p. 9.

[65] *Ibid.*, p. 9.

[66] *Ibid.*, p. 10.

TABLE C-1. ALP PROJECT COMPONENTS, BENEFITS, AND ESTIMATED COSTS

Component	Benefits	Total Est. Cost ($ million)
Reliability Component (Responsible Entity):		**$71.9**
• New 230 kV line from Labbe - Bonin (LUS) • 500/230 kV auto transformer at Wells (Cleco) • New 230 kV line from Wells - Labbe (Cleco/LUS) • New 230 kV line from Labbe - Meaux (EGSL) • 230/138 kV auto transformer at Meaux (Cleco)	• Relieves Entergy TLR procedures (allows for increased economic import) • Accommodates load growth and improves load serving capability[67]	Allocated roughly based on load ratio share and then matched with component ownership
Economic Component (Responsible Entity):		**$128.1**
• 500/230 kV auto transformer at Richard (Cleco/EGSL) • New 230 kV line from Richard - Sellers Road (Cleco) • New 230 kV substation at Sellers Road to connect Labbe-Meaux and Richard - Sellers Road (Cleco) • New 230 kV substation at Segura near Moril (Cleco) • New 230 kV line from Sellers Road - Segura (Cleco) • 230/138 kV auto transformer at Segura (Cleco) • New 138 kV line from Segura - Moril (Cleco)	• Allows removal of must-run designation for Cleco's Teche and LUS's Bonin • Economic benefits largely to Cleco (est. fuel cost savings of $906 million 2010-2039) • Additional generation dispatch flexibility and potential fuel cost savings for LUS	Approx. 70% allocated to Cleco (with smaller shares to EGSL and LUS) and then matched with component ownership
Total Estimated Cost *(as of 2008)*		**$200.0**

Sources and notes: Components from: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008. Benefits from: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008 and Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC, Louisiana Public Service Commission Docket No. U-31196, "Direct Testimony of Mark F. McCulla," November 13, 2009. Cost estimates from: Southwest Power Pool, Inc., Cleco Power - Lafayette Utilities System-SPP/SPPICT-Entergy Joint Transmission Planning Study, "Reliability and Economic Study for the 2008 Transmission Expansion Plan of the Acadiana Area Load Pocket," October 2008.

Cost allocation was developed by first determining which portion of the entire project addressed reliability concerns and which portion addressed economic needs. For the reliability component, cost allocation was based on an adjusted load ratio share of Cleco, LUS, and EGSL as a proxy of received reliability benefits. (The adjustment was made to account for additional loads that each utility served

[67] *Ibid.*, p. 19.

under contract, using projected 2012 load.) The adjusted load ratio shares as applied to the estimated reliability component costs are shown in column [2] in Table C-2.

TABLE C-2. ALP PROJECT RELIABILITY COMPONENT BY ADJUSTED LOAD RATIO SHARE

			Allocated ALP Project Reliability Component Cost ($ Million)		
Sponsor	Adj. Projected 2012 Load (MW)	Adj. Load Ratio Share (%)	Based on Adj. Load Ratio Share	Based on Ownership	Based on Revised Estimates
	[1]	[2]	[3]	[4]	[5]
EGSL	877	47%	$33.6	n/a	n/a
Cleco	732	39%	$28.0	$26.6	$30.1
LUS	270	14%	$10.3	n/a	n/a
Total	**1,879**	**100%**	**$71.9**		

Sources and notes:

[1]: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008, pp. 21-22.

[2]: Percentage of each utility's projected load as a share of total.

[3]: [1] x [2].

[4]: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008, p. 22.

[5]: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, Subdocket A, "Direct Testimony of Terry John Whitmore," November 4, 2008, p. 6.

According to filings made on behalf of Cleco, the $28.0 million share of the reliability component (as shown in column [3] of Table C-2 above) was approximately aligned with the $26.6 million direct cost of constructing and owning the new transmission components interconnected to the Cleco system (as shown in column [4]). Therefore, in the first iteration of the Memorandum of Understanding ("MOU"), Cleco assumed $26.6 million in reliability-related ALP Project costs. In an updated MOU, Cleco and LUS each slightly expanded their projected buildouts with Cleco's total estimated reliability costs increasing by $3.5 million to $30.1 million (as shown in column [5]). Despite this revision, the underlying allocation did not change. In fact, the MOU is structured so that each utility is individually responsible for components of the ALP Project in a way that is roughly commensurate with benefits received. For the economic component, Cleco is the main beneficiary and therefore will own and construct the majority of those facilities at a total estimated cost of $87.1 million.[68]

There are at least five important lessons learned from the ALP Project case study, as summarized by SPP Staff.[69] First, there was general agreement that the various problems identified in the ALP had to be

[68] Whitmore Testimony, 7/14/08, p. 23.

[69] Kelley, David, SPP Seams Steering Committee, "Acadiana Load Pocket," memo to Seams Cost Allocation Task Force ("SCATF"), September 12, 2011.

addressed and that **a seams solution could provide both individual and joint benefits**. Second, it was recognized that **needs and drivers were different for the parties involved**. The ALP Project provided both reliability and economic benefits, which accrued to parties differently. Third, **transmission planning and cost allocation was jointly considered** so that a solution and its associated costs produced equitable results. Fourth, **cost allocation via transmission ownership, not financial transfers, was easier to accomplish**. Especially for non-market regions and utilities, financial transfers may not even be possible or prove difficult to implement. For the ALP Project, each seams entity shared costs by building, owning, and maintaining a segment of the buildout. Similarly, each entity was responsible for recovering approved ALP Project-related costs through its own transmission tariff. Parties were also able to agree to the **approximate magnitudes of contribution rather than a strict matching of costs to benefits**. Cost allocation was determined by considering the approximate magnitude of the reliability and economic benefits to each party involved while also considering the geographic location of the future facilities and operational flexibility. And finally, **strong state-level participation** via Commissioner Jimmy Field of the Louisiana Public Service Commission and the ICT staff helped facilitate the process.