NARUC

National Association of Regulatory Utility Commissioners

Collaborative Enhancements to Unlock Interregional Transmission

Energy and Environmental Economics, Inc. (E3)

June 2024

Table of Contents

List of Figures and Tables

Disclaimer

Acknowledgments

This report was written by Lakshmi Alagappan, Jack Moore, Ben Joseph, Stuart Mueller, and Arne Olson at Energy and Environmental Economics, Inc. (E3), and is based on work supported by the U.S. Department of Energy under Award Number DE-OE0000925.

The authors would like to thank Sarah Fitzpatrick, Senior Technical and Policy Advisor in the NARUC Center for Partnerships & Innovation for her partnership and guidance throughout the development of this report.

In addition, the authors thank the following individuals for their contributions, comments, and insights, which helped to shape and enhance the paper:

- **Hon. Riley Allen,** Vermont Public Utilities Commission
- **Stephen Bennett,** PJM Interconnection
- **Melissa Birchard,** U.S. Department of Energy
- **Christina Drake,** Midcontinent Independent System Operator
- **Hon. Andrew French,** Kansas Corporation Commission
- **Erik Hanser,** Michigan Public Service Commission
- **Asim Haque,** PJM Interconnection
- **Patrick Harwood,** U.S. Department of Energy
- **Marcus Hawkins,** Organization of MISO States
- **Natasha Henderson,** Southwest Power Pool
- **Juliet Homer,** Pacific Northwest National Laboratory
- **Hon. Darcie Houck,** California Public Utilities Commission
- **Simon Hurd,** California Public Utilities Commission
- **Gretchen Kershaw,** U.S. Department of Energy
- **Advait Rode,** Michigan Public Service Commission
- **Danielle Sass Byrnett,** NARUC
- **Hon. Doug Scott,** Illinois Commerce Commission
- **Hon. Dan Scripps,** Michigan Public Service Commission
- **Christina Simeone,** National Renewable Energy Laboratory
- **Michael Skelly,** Grid United
- **Robert Taylor,** Invenergy

Executive Summary

The electricity system in the United States is poised to undergo significant changes over the coming decades. After ten years in which electric loads remained relatively flat across much of the country, expectations for load growth have increased dramatically due to electrification, development of new industry, and data center loads. At the same time, the country's generation mix is rapidly evolving, as a significant number of fossil-fueled generators are approaching the ends of their lives—a trend supported in many jurisdictions by clean energy and carbon reduction goals—and increasing amounts of renewable and energy storage resources are coming into service to meet clean energy policy goals and voluntary commitments. This transition is accelerating due to underlying economic conditions as well as policy advancement and incentives introduced by the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA).

Multiple recent studies highlight significant benefits associated with expansion of interregional transfer capabilities for efficiently adapting to these changes. Despite these proposed benefits, few, if any, interregional transmission projects have been built in recent memory. The objective of this report is to confront the barriers to interregional transmission that exist today and address them with potential reforms and collaborative solutions. This report identifies solutions with the potential for immediate beneficial impact on interregional transmission with the ultimate goal of allowing more effective identification and advancement of interregional transmission projects that create the most positive net value to the participating systems. It distinguishes between states, federal government, and planning regions as key actors in implementing solutions designed to be flexible to accommodate regional differences.

The challenges and potential solutions have been grouped across three areas related to interregional transmission (see **Figure 1**) including: **planning**—the process of identifying transmission projects, assessing their technical and economic viability, approving cost allocation, and awarding development rights; **permitting**—the siting and permitting processes which are generally conducted by state regulatory agencies; and **operations**—the frameworks under which capacity on interregional transmission is allocated and optimized in the delivery of electricity.

Figure 1. Potential Solutions to Interregional Transmission Challenges

Planning

Most transmission planning activities occur either at the regional (e.g., within regional transmission organizations (RTOs), within independent system operators (ISOs), outside RTOs/ISOs) or the subregional level, and while Federal Energy Regulatory Commission (FERC) requires interregional coordination of transmission planning processes, it does not require formal interregional planning.[1] This means that while neighboring regions convene to share results of regional transmission studies, they are not required to collaboratively identify interregional transmission needs and the solutions to meet those needs.

The limited development of interregional transmission planning can be largely attributed to three components—Lack of Planning Motivators, Cost Allocation, and Planning Process Misalignment and Analysis Limitations—and the solutions to these challenges include enhancements to enable planning regions to seek interregional collaboration and improvements to reconcile planning processes. Specifically:

- *Coordinated Interregional Planning:* Planning regions could expand coordination to determine joint transmission needs and identify interregional transmission solutions. Once joint needs are established, regions would be motivated to reconcile planning processes, or develop new ones, to identify interregional projects meet these needs more cost effectively than regional alternatives. This kind of collaboration can be initiated by planning regions themselves, from state influence, or requirements and incentives from the federal level.
- *Process Harmonization:* Regions could standardize universal best practices in regional and interregional transmission planning to ensure the best available projects are being identified and thoroughly analyzed, and costs are being allocated equitably, to reduce friction in interregional collaboration. Harmonizing planning approaches and timelines would enable efficient interregional collaboration and allow projects to avoid delays due to asynchronous planning processes.
- *Model and Data Harmonization:* Planning regions could strive to reconcile differences in modeling techniques, tools, data inputs, and benefit calculation methods to enable streamlined collaboration on interregional transmission analysis.

Permitting

Once a project is awarded development rights, it moves on to siting, route approval, and permitting. While the planning of interregional transmission projects takes place at the system level (which is multi-state), projects must apply for permitting at a state level and the permit applications for a single project are independent and unconnected across states. In practice, there is a wide range of how these proceedings are conducted from state to state, although they almost always require determination of project need and demonstration of how the project serves the public interest. Since siting and permitting occurs at the end of the project's development process, state regulators typically have the final decision over which transmission projects are built.[2]

Permitting processes can pose significant barriers to the development of beneficial interregional projects. These challenges arise from limited resources at permitting agencies, differences between permitting processes, and difficulties in meeting permitting criteria independently across every state through which an interregional project passes. While challenging, there are solutions to these barriers that would support successful siting and permitting of beneficial interregional transmission projects. These solutions include:

1 J.H. Eto and G. Gallo, *Interregional Transmission Coordination: A Review of Practices Following FERC Order Nos. 890 and 1000* (Berkeley, CA: Lawrence Berkeley National Laboratory, Energy Analysis and Environmental Impacts Division, October 2019), 9, https://eta-publications.lbl.gov/sites/default/files/interregional_transmission_coordination_final_oct2019.pdf.

2 Which transmission projects require state permits differs across states. Generally, most states require permits for high voltage transmission (200 kV and above).

- *State Transmission Authorities:* States create and provide funding to special agencies to engage in transmission planning activities, analyze transmission needs, provide siting guidance to developers, and participate in or even fund transmission development.
- *Host Community Benefits:* Projects could be designed to provide non-energy benefits to host communities to ensure states that bear the physical impact of a project also receive benefits. These benefits can include providing jobs and job training, revenue sharing, and investment in capital projects, social programs, and economic development opportunities.
- *Streamlined Need Determination Across Planning and Permitting Processes:* The interregional planning process and the permitting processes often each include a separate assessment of the need for a project. Relying on the same analysis for both need determinations could streamline permitting processes.
- *Multi-State Evidentiary Record:* States could coordinate evidentiary proceedings to synchronize permitting timelines and standardize data collected to inform decision making. Different states may still have different priorities and may choose to include different types of benefits in what they consider, but standardizing a common set of underlying facts, models, and timelines could help expedite project approvals.

Operations

Finally, after successful planning and permitting of interregional transmission lines, operational approaches could be optimized so these lines can be utilized in the most valuable manner. Actualizing the modeled benefits depends not exclusively on the *existence* of new transmission facilities, but also on *how the facilities are operated*, and expectations of that operation by system planners and market participants.

Recent historical data for the operation of existing interregional transmission lines indicate that interregional interties are often underutilized even when flows are most valuable. This is often due to factors including economic charges to schedule and transmit power between regions, scheduling requirements up to 75 minutes before energy is delivered reducing its ability to support near-term changes, bilateral agreements for power transfers that are not responsive to price, and a lack of reliable protocols for how to operate interregional lines during times of extreme grid conditions.

Solutions to these operational challenges drive at enabling interregional transmission to be scheduled and used both responsively and at lower cost. Specifically, potential solutions include:

- *Reduce Transaction Charge Impacts:* The balance between fixed and volumetric charges can be restructured to minimize impacts on scheduling decisions while maintaining asset owners' revenue requirements.
- *Reduce Advanced-Time Requirements:* Reducing the time between scheduling and operations will allow for transmission to be more supportive of real-time conditions.
- *Develop Optimized Scheduling Mechanism:* New operational mechanisms modeled after the Western Energy Imbalance Market and Europe's market coupling efforts can optimize use of unutilized interregional transmission headroom.
- *Improve Preparation for Resiliency:* Market operators could work to define possible emergency conditions and establish protocols for rapid communication and operations during periods of high resiliency need.

Conclusion

Planning, permitting, and operating interregional transmission to maximize system benefits is challenging. But in the face of massive transformation of the power sector over the coming decades, it is important to take steps to enable the identification of beneficial interregional transmission through planning, allow for those projects to be evaluated and accurately valued during the permitting process, and operate those projects to maximize system benefits when put into service. Not taking these steps could mean the development and operation of a more expensive grid (on both the generation and transmission side), and increased frequency of reliability events. It could further lead to the introduction of disruptive solutions, such as federal preemption, that limit states' ability to advocate for transmission that fits their specific needs and priorities.

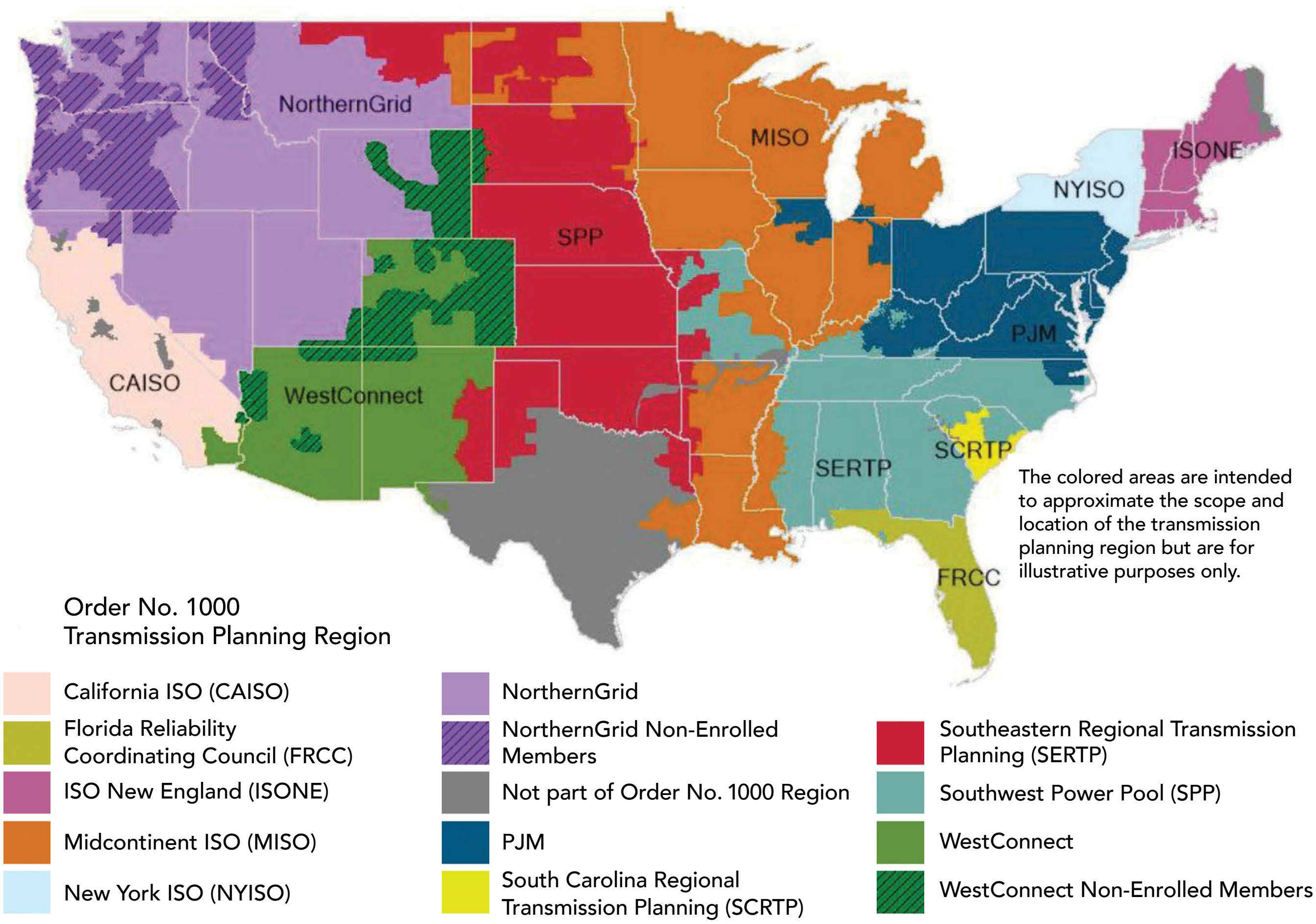
Taking the steps suggested in this report may not be the "path of least resistance," as they require states and planning entities to engage and collaborate in ways that are potentially new and different from current practices. The elements of engagement and collaboration discussed in the report are derived from successful examples seen recently in different jurisdictions, which suggest they could result in meaningful state- and region-led transmission planning if employed on a wider basis going forward.

Introduction

The electricity system in the United States is poised to undergo significant changes over the coming decades. After ten years in which electric loads remained relatively flat across much of the country, expectations for load growth have increased dramatically due to electrification, development of new industry, and data center loads. At the same time, the country's generation mix is rapidly evolving, as a significant number of fossil-fueled generators are approaching the ends of their lives—a trend supported in many jurisdictions by clean energy and carbon reduction goals—and increasing amounts of renewable and energy storage resources are coming into service to meet clean energy policy goals and voluntary commitments. This transition is accelerating due to underlying economic conditions as well as policy advancement and incentives introduced by the IRA and the IIJA.

The rapid transformation of the electricity system is occurring in an era of increasing climatic uncertainty and volatility. In recent years, the tally of extreme weather events that have strained the capabilities of the electric grid has increased steadily and has required operators to shed load in a number of cases. Winter storms such as Uri and Elliott have caused widespread unplanned outages of power plants with devastating impacts on customers, while heat waves of unusual severity and geographic breadth have triggered record electricity demands that have at times exceeded the generating capabilities of the system.[3]

Figure 2. FERC-Defined Transmission Planning Regions[4]



3 Extreme heat in August 2023 in Texas created price spikes and nearly caused sweeping power outages; S. Disavino, "Texas Heat Wave Spurs Power Prices to Their Highest Since 2021 Freeze," Reuters, August 25, 2023, https://www.reuters.com/business/energy/texas-power-prices-jump-soaring-demand-heat-wave-2023-08-25/.

4 Transmission planning regions are entities regulated by FERC that are tasked with identifying transmission needs and the facilities that can meet those needs in a cost-effective manner; Federal Energy Regulatory Commission, "Regions Map Printable Version Order No. 1000," November 9, 2021, https://www.ferc.gov/media/regions-map-printable-version-order-no-1000.

Against this backdrop, there has been a renewed interest in the potential benefits of electric transmission. In particular, the prospect of investments in interregional transmission—defined as transmission spanning multiple transmission planning regions (as defined by FERC and depicted in **Figure 2**)—has received considerable attention.

Multiple recent studies highlight significant benefits associated with expansion of interregional transfer capabilities, particularly in the context of its ability to (1) enable more efficient decarbonization of the electricity system, and (2) increase resilience of the bulk electric system against increasingly frequent and severe extreme weather events:

- National Renewable Energy Laboratory's (NREL) *Interconnection Seams Study* identified positive benefit-cost ratios to expanding transfer capabilities between the Eastern and Western Interconnections and Electric Reliability Council of Texas (ERCOT).[5]
- Lawrence Berkeley National Laboratory (LBNL) found that in many cases, the value of interregional transmission projects exceeds the value of intraregional projects, with a substantial portion of benefits accruing during extreme grid conditions.[6]
- Princeton's *Net Zero America Study* found that achieving a net zero energy sector by 2050 requires expanding the amount of transmission currently installed two to five times over.[7]
- MIT's *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System Study* finds that national coordination of transmission and generation expansion and operations can nearly halve the cost of decarbonization in comparison to a scenario without interstate coordination.[8]
- The U.S. Department of Energy's (DOE) *2023 National Transmission Needs Study* concluded that more than doubling interregional transmission transfer capacity by 2035 would provide net energy cost savings in the moderate load/high clean energy growth scenario reflecting current policy-driven growth trajectories (see **Figure 3**)[9],[10]

As these studies highlight, the benefits identified for interregional transmission projects are most often driven by diversity between the regions, including differences in the following:

- Composition and timing of regional power demand;
- Regions' relative quantities of resources built to supply that demand;
- Timing of unexpected generator or transmission system outages; and
- Weather.

Weather-related differences—from seasonal rainfall and temperature level, down to sub-hourly cloud cover and wind conditions—often vary more greatly for places that are further apart. The studies illustrate how interregional lines, which typically connect locations that are geographically distant, are able to unlock the benefits driven by weather diversity, which creates differences between regions' relative power demand and renewable resource output at any point in time. As increasing buildout of wind and solar projects lead these

---

5 National Renewable Energy Laboratory, "Interconnections Seam Study," https://www.nrel.gov/analysis/seams.html.

6 Lawrence Berkeley National Laboratory, "Regional and Interregional Transmission Have Significant Economic Value," August 1, 2022, https://emp.lbl.gov/news/regional-and-interregional.

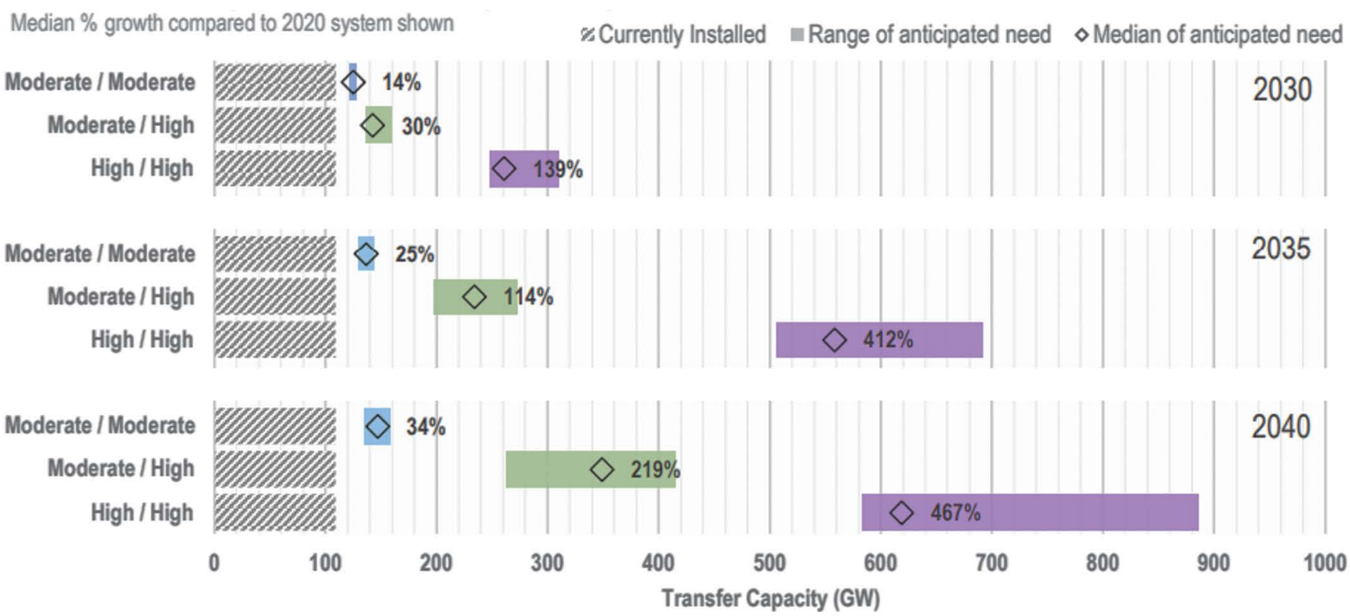
7 Net-Zero America and Princeton University, "Net-Zero America: Potential Pathways, Infrastructure, and Impacts," https://netzeroamerica.princeton.edu/.

8 P.R. Brown and A. Botterud, "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System," Joule 5, no. 1 (2021): 115–134, https://www.sciencedirect.com/science/article/pii/S2542435120305572.

9 This result was driven by load growth and renewable energy expansion assumptions determined to achieve more than 80 percent clean energy penetration by 2040, a figure chosen to resemble a future enabled by current policy at local, utility, state, and federal levels, including the IIJA and IRA.

resources to comprise a growing share of the generation mix of each region, and as weather conditions exhibit increasingly extreme and unpredictable patterns, the expected benefits from unlocking diversity between regions also likely increases.

Figure 3. Anticipated Need for Interregional Transfer Capability Expansion in DOE's Transmission Needs Study[10]



Interest in developing transmission across broader footprints is not new. FERC Order 890 (issued in 2007) and Order 1000 (issued in 2011) delineated regional transmission planning principles and established transmission planning processes for regions to implement within their footprints. Key focuses of these orders included improvements in coordination, information sharing, regional planning participation, and transmission cost allocation. In addition, Order 1000 addressed interregional transmission planning by requiring neighboring planning regions to evaluate whether interregional solutions were more efficient or cost-effective than their regional needs. Without a requirement for more proactive interregional collaboration to identify transmission needs and the solutions to meet those needs, Order 1000's impact on actual development has been modest.[11] From 2011 to 2020, only about four percent of national investment in transmission has occurred at the interregional level,[12] and most projects are relatively small in scale and address congestion and reliability issues at regional seams. This begs the question: **if interregional transmission is as valuable as the studies show, why has development to date been so limited?**

The barriers to interregional transmission development have been studied extensively and cataloged in a number of other reports (see Appendix A: Literature Review). The most significant ways in which existing processes are not well-equipped to efficiently identify and support these types of projects are:

10 This graphic was created by reviewing results from several nation-wide capacity expansion studies. The studies were grouped into categories based on their underlying assumptions on load growth and clean energy penetration. Moderate load growth is defined as being between a 2021 baseline of 3,974 TWh and 7,000 TWh. High load growth exceeds 7,000 TWh. Moderate clean energy penetration ranges between the 2021 baseline of 38.6 percent and 80 percent by 2040. High clean energy penetration exceeds 80 percent by 2040. Interregional transmission capacity expansion results in these studies are reported as the percent increase by category groupings and by year (2030, 2035, and 2040); U.S. Department of Energy, *National Transmission Needs Study* (Washington DC, October 2023), 134, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

11 Federal Energy Regulatory Commission, "18 CFR Part 35: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities" (July 21 2011), 271, Section III.C, https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf.

12 U.S. Department of Energy, *National Transmission Needs Study*, 22; the value of four percent was calculated based on Table IV-1 on p. 22 showing capital costs of transmission investments from 2011 to 2022.

- *Planning processes* between planning regions **lack proactive, well-aligned coordination and fail to identify interregional transmission needs and projects** that would have opportunity to create significant value;
- *Planning and permitting processes* **fail to fully recognize the value of an identified project**, resulting in denied or delayed approvals for projects that would provide positive net benefits if the full value were recognized;
- After a project is placed in service, the *operational framework* for transactions between regions **fails to effectively utilize an in-service project's capability** to maximize its value to the system.

Successfully developing interregional transmission projects at the scales contemplated in forward-looking studies will require overcoming these barriers, but the question of how best to do so remains unresolved. Some solutions have favored top-down, standardized policy approaches and market intervention—for example, through federal mandates for minimum transfer capabilities between regions as suggested in the BIG WIRES proposed legislation.[13] Despite their well-intentioned origins, these types of "one-size-fits-all" solutions often erode local nuance and economic principles integral to existing practices. State regulators have consistently argued that solutions must respect regional differences and allow for flexibility to accommodate these regional differences.[14] When developing solutions, policy makers should attempt to find a balance between the effect of standardizing planning, permitting, and operational practices would have on streamlining interregional collaboration while maintaining the ability for these processes to reflect local and regional needs. Additionally, it is important to seek greater consistency between the practices of adjacent regions. These neighboring regions can work together on a bilateral basis to seek greater standardization between their approaches. By contrast, greater variation in the approaches used in regions at the opposite ends of the country pose less of a problem for development because single transmission projects are unlikely to span such a great distance.

Objective and Scope of the Report

The objective of this report is to provide an alternative path that directly confronts the barriers that exist today and addresses them with reforms and collaborative solutions. Several assumptions are embedded in the potential solutions. First, this report operates under the assumption that the solutions that will be the most actionable and make the most immediate impact will be those that, to the extent possible, preserve existing jurisdictional oversight among state or federal regulators. Second, the report assumes that collaborative solutions with buy-in from state and federal regulators, system operators, and other impactful stakeholders will enable the most effective results.

This report also aims to focus more narrowly on solutions to facilitate maximizing the value of interregional transmission. While reform of regionally focused transmission planning practices will generally benefit interregional transmission, this report focuses more directly on interregional transmission processes. This report identifies solutions with the potential for immediate beneficial impact on interregional transmission planning, permitting, and operations. The ultimate goal of these potential improvements is to allow more effective identification and advancement of interregional transmission projects that create the most positive net value to the participating systems.

---

13 The BIG WIRES Act was introduced to the U.S. Senate in September 2023, and if passed, would direct FERC to establish a standard for minimum interregional transfer capacity across seams of all transmission planning regions set at the lesser of (1) 30 percent of each region's peak load or (2) at each region's peak transmission plus 15 percent of its peak load; Office of U.S. Senator for Colorado Hickenlooper, "Hickenlooper, Peters Introduce BIG WIRES Act to Reform Permitting, Lower Energy Costs," September 15, 2023, https://www.hickenlooper.senate.gov/press_releases/hickenlooper-peters-introduce-big-wires-act-to-reform-permitting-lower-energy-costs/.

14 National Association of Regulatory Utility Commissioners, "Federal Energy Regulatory Commission Comments of the National Association of Regulatory Utility Commissioners," August 17, 2022, 9, https://pubs.naruc.org/pub/F3AF556A-1866-DAAC-99FB-BFE2357A9443.

We focus on the challenges and potential solutions within three domains related to interregional transmission:

- **Planning:** Transmission planning is the process of identifying transmission projects, assessing their technical and economic viability, approving cost allocation, and awarding development rights. This responsibility is regulated by FERC and administered by regional transmission planning entities in the regions depicted in Figure 2. Interregional transmission projects, which cross the boundaries of these regions, are evaluated by the two or more planning entities from which they seek cost allocation.
- **Permitting:** After projects are identified and awarded development rights through the planning process, they move to the siting and permitting processes that are generally conducted by state regulatory agencies.[15], [16] Siting is the process of determining and approving the route a transmission line will take. Permitting is the process of deciding whether a project is in the public interest and issuing a permit that codifies approval, such as through a Certificate of Public Convenience and Necessity (CPCN).[17] These two processes (siting and permitting) are often referred to together, as they are often conducted by the same entities, and permitting decisions are contingent upon findings of the siting process. Given siting and permitting occurs at the end of the project's development process, state regulators typically have the final decision over which transmission projects are built. This final step underscores the importance of the state regulatory role in interregional transmission development processes.
- **Operations:** After the project is planned and permitted, it is constructed and put into service. Typical operations of interregional interties do not optimize their use in real time; rather, interregional transfers must be scheduled up to 75 minutes ahead of the operating interval[18] based on a forecast of expected prices in each connected market—typically through a process termed Coordinated Transaction Scheduling (CTS). If conditions change in either region—such as an increase in load from the exporting region compared to its earlier forecast, a reduction in the amount of expected generation from a variable energy resource, or unexpected forced generator outages, the scheduled transaction that happens may end up being significantly different than what would be economically optimal. Additionally, the uncertain returns of such transactions can cause market participants to bid more hesitantly for interregional transactions. Operational approaches to address challenging resiliency situations can also fail to fully utilize interregional transmission if regions are insufficiently prepared to coordinate in emergency scenarios.

Research for this report included a literature review of industry, government, and academic reports, as well as documentation of interregional transmission planning practices, permitting requirements, and intertie operations. The literature review was supplemented by interviews with relevant stakeholders with direct experience in the interregional transmission industry. Interviewees spanned state regulatory commissions, transmission planners and planning entities, and interregional transmission developers. These discussions helped provide context for where interregional transmission planning, permitting, and operations are working well and where improvement or change is most warranted.

---

15 W.H. Smith, Jr., *Mini Guide on Transmission Siting: State Agency Decision Making* (Washington DC: National Council on Electricity Policy and National Association of Regulatory Utility Commissioners, December 2021), 2, https://pubs.naruc.org/pub/C1FA4F15-1866-DAAC-99FB-F832DD7ECFF0.

16 While typically performed by state regulators, permitting authorities can differ by state. Some states have boards or committees specifically dedicated to siting and permitting. Some states have delegated siting and permitting processes to county and local governmental entities. If a project crosses federal or tribal land, projects may need to get approvals from relevant federal and tribal agencies.

17 In addition to the CPCN process, permitting includes environmental permitting to ensure environmental and cultural resources are maintained and not overly burdened by project development. Environmental permitting is often conducted by non-state and federal entities.

18 An operating interval is the time period for which system operators plan dispatch of the electricity system. These intervals can be as short as five minutes. By continuously planning for successive operating intervals, system operators match changes in generation with changes in load.

This report focuses mostly on identifying barriers and solutions for interregional transmission projects seeking cost allocation through regional planning authorities and does not comprehensively address the challenges that merchant transmission projects, which seek cost recovery by contracting directly with customers, may face.

While this report was being finalized, several key policy decisions were made at the federal level. This includes FERC Order 1920,[19] focusing on transmission planning reform, and Order 1977,[20] which amends FERC's federal transmission permitting authority. The DOE also announced a series of rulemakings impacting federal permitting, announcing new funding opportunities for transmission, and more.[21] These developments address some of the potential solutions identified in this report.

The report is organized into four sections: the first three focus on the challenges and potential solutions within each of the interregional transmission domains (planning, permitting, and operations); the last section distills key takeaways from the research conducted.

19 Federal Energy Regulatory Commission, "18 CFR Part 35: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation," May 13, 2024, https://ferc.gov/media/e1-rm21-17-000.

20 Federal Energy Regulatory Commission, "18 CFR Parts 50 and 380: Applications for Permits to Site Interstate Electric Transmission Facilities," May 13, 2024, https://www.ferc.gov/media/e-2-rm22-7-000.

21 The White House, "Fact Sheet: Biden-Harris Administration Announces Key Actions to Strengthen America's Electric Grid, Boost Clean Energy Deployment and Manufacturing Jobs, and Cut Dangerous Pollution from the Power Sector," April 25, 2024, https://www.whitehouse.gov/briefing-room/statements-releases/2024/04/25/fact-sheet-biden-harris-administration-announces-key-actions-to-strengthen-americas-electric-grid-boost-clean-energy-deployment-and-manufacturing-jobs-and-cut-dangerous-pollution-from-the/.

Interregional Transmission Planning

Approval of new transmission projects in regional transmission planning processes traditionally requires that they meet at least one of the following three criteria:

- **Reliability:** upgrades needed to meet network reliability requirements, interconnect new generation, and meet other service requests;
- **Economics:** upgrades justified on the basis of benefits from reductions in operating costs and congestion; and
- **Public policy:** upgrades needed to support or enable state or other policy objectives, for instance, delivery of renewable resources to meet a state Renewable Portfolio Standard (RPS).

Most transmission investments today are reliability projects identified by incumbent transmission owners to comply with reliability standards.[22] These projects do not require economic analysis for final approval of need determination. Economic and public policy projects require an assessment to determine if project benefits, whether driven by cost savings (economic) or to meet state goals (public policy), outweigh the costs. With the addition of Order 1920, regular long-term planning processes will require multi-value planning and could lead to the integration of cost allocated projects that are identified in part to meet reliability needs.

Transmission planning activities typically occur either at the regional level (conducted by regional transmission entities) or the subregional level (conducted by transmission owners). FERC requires interregional coordination of transmission planning processes but stops short of requiring full interregional planning.[23] This means that neighboring regions regularly convene to share results of regional transmission studies and solicit interregional transmission solutions from third parties, but they are not required to establish processes to collaborate on project identification and analysis to meet interregional transmission needs. Instead, each region takes the interregional projects proposed in coordination meetings and uses their own regional planning process to determine whether the interregional projects meet their own transmission needs more effectively than other regional alternatives being considered. If both regions approve the same interregional project, the interregional coordination committees determine a cost allocation framework commensurate with the distribution of benefits to each region. All planning regions have set up coordination committees with their neighbors, and while these committees meet FERC's coordination requirements, they have not been historically successful at identifying and allocating the costs of mutually beneficial interregional transmission projects.[24]

The limited record of successful interregional transmission development was a point of emphasis in both the literature review and interviews conducted in support of this effort.

There are several reasons for the limited identification of interregional transmission solutions. First, regional and interregional planning processes often occur asynchronously. When process timelines are misaligned, interregional transmission projects are assessed by planning regions after their approved regional transmission plans have met local and regional transmission needs, leaving few opportunities for interregional transmission projects to address known needs. Second, planning processes often do not address multiple transmission needs (reliability, economic, and public policy) simultaneously, undervaluing projects that meet multiple transmission

22 Federal Energy Regulatory Commission, "FERC State of the Market Report: The Need for Transmission" (Washington DC, March 27, 2024), https://www.ferc.gov/news-events/news/ferc-state-market-report-need-transmission.

23 Eto and Gallo, *Interregional Transmission Coordination*, 9.

24 A few key exceptions to this pattern are the PJM-MISO Targeted Market Efficiency Projects and the SPP-MISO Joint Targeted Interconnection Queue projects, but both are limited in geographic scope, transmission needs considered, and benefits analyzed.

needs and thus constraining the pool of potentially feasible regional projects.[25] When interregional projects are considered, the focus tends to narrow even further. Interregional project analysis is predominantly focused on addressing regional economic needs based upon an even more narrowly defined set of economic benefit metrics, thereby limiting the opportunity for viable interregional projects even further.

Understanding why this is the case is a prerequisite to designing effective solutions; this chapter identifies the most direct factors that have served as impediments to interregional transmission before discussing potential solutions that could enable more effective planning and engagement.

Challenges with Interregional Transmission Planning

The interregional transmission coordination processes are complex both technically and administratively, with participation and oversight from multiple planning entities. This dual complexity gives rise to many challenges in planning for interregional transmission, which are discussed in more detail in this section.

This section frequently uses PJM Interconnection and Midcontinent Independent System Operator (MISO) to illustrate challenges and highlight best practices in their respective planning efforts and interregional collaborations. The PJM/MISO seam was of particular interest because it was identified by the *DOE National Transmission Needs Study* as having the greatest need for expanding interregional transfer capability.[26]

Lack of Planning Motivators

Many interviewees mentioned that the lack of a clearly articulated need for proactive, collaborative interregional transmission planning (referred to in this report as a planning motivator) often leaves planners to deprioritize interregional transmission projects over regional alternatives. Without a reason to come to the table and work through interregional transmission challenges, they rely on established regional planning processes. Planning motivators could include identifying common transmission needs across regions creating an intrinsic drive to collaborate or external pressure from stakeholders or regulatory requirements to engage in interregional transmission planning. While FERC Order 1000 requires interregional coordination of transmission planning processes, there is no formal mandate for interregional *planning*.[27] To meet the coordination requirement, planning entities regularly convene to share information after the conclusion of their regional transmission studies and solicit interregional transmission solutions from third parties. With few exceptions, most have not established formal processes to collaborate on project identification and analysis. Projects proposed in these interregional coordination forums may subsequently be analyzed by individual planning entities, but the need to secure multiple approvals through multiple regional planning processes—often using different approaches and operating on asynchronous cycles—creates a burden that is difficult for most proposed projects to overcome. Given the sequential nature of existing transmission planning processes where most planning entities evaluate interregional projects after identifying local and regional reliability, economic, and public policy projects, many needs are already taken care of by the time interregional projects are even considered.[28]

---

25 Order 1920 requires transmission evaluation for long-term planning to include at least the seven mandatory transmission benefits listed in the Planning Methods Harmonization section below. These categories include both reliability and economic metrics. Requirements for modeling assumptions include public policy impacts on key modeling inputs such as generation resource mix and load growth. Together, these requirements will aim to promote long-term planning approaches that value reliability, economic, and public policy needs together rather than the historical approach of assessing them separately. Order 1920, however, requires that long-term planning happen at least once every five years. Thus, there likely will continue to be intermediary transmission studies (occurring between the long-term study cycles) that identify and address new transmission needs. In some regions, such interim studies may continue to take a more piecemeal planning approach for individual benefits.

26 U.S. Department of Energy, *National Transmission Needs Study*.

27 Eto and Gallo, *Interregional Transmission Coordination*, 9.

28 J.P. Pfeifenberger, K. Spokas, J.M. Hagerty, and J. Tsoukalis, "A Roadmap to Improved Interregional Transmission Planning" (The Brattle Group, November 30, 2021), 9, https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

There has been limited motivation from states to pursue interregional planning as well. States naturally focus on activities within their respective boundaries, especially when it comes to infrastructure investment and the potential for economic development. Many states prioritize development of infrastructure within their state boundaries to ensure local economic benefits from the investment. The lack of encouragement from states to pursue interregional transmission can limit its development by not providing the regulatory signal for cost recovery to utilities who may otherwise pursue investments in interregional transmission to support their customers.[29] Similarly, without a strong voice from states signaling their interest in interregional projects, transmission planning entities may not see the need to complicate an already technical planning process.

It should be noted that messaging from states with regards to interregional transmission may be shifting. An example of this shift is noted in a recent joint letter from the Organization of MISO States (OMS) and the Organization of PJM States, Inc. (OPSI) in response to recent extreme weather events, which encouraged PJM and MISO to engage in joint transmission modeling and work with state regulators to identify state reliability and policy objectives.[30]

Cost Allocation

Cost allocation, the process of determining who pays for what portion of new transmission projects, continues to be one of the biggest hurdles to the development of interregional transmission projects. No transmission project has been selected for cost allocation at the interregional level since Order 1000 was issued in 2011.[31] Costs are meant to be allocated by estimating the transmission benefits accrued to each region impacted by a project and assigning costs to those regions proportionately. The financial repercussions of benefit calculations makes the benefit analyses heavily scrutinized.[32] Planning regions may also use different benefit metrics, calculate benefit metrics differently, or use different tools for benefit calculation, which can complicate the coordination of transmission studies for interregional projects (see Planning Process Misalignment and Analysis Limitations section for more detail). This cost allocation practice incentivizes cautious use of only the most common benefit metrics to avoid any perceived undue cost burden between the two regions; however, eliminating the use of certain benefit metrics diminishes the identified value of interregional transmission projects, making them challenging to justify financially and can result in the exclusion of otherwise beneficial projects.

The difficulty with cost allocation has contributed to the rise in merchant transmission development. With undermined faith in cost allocation processes, developers are left to seek cost recovery by securing offtake agreements from individual or groups of customers. This avoids the challenges of navigating regional planning and cost allocation processes by ensuring financial security through direct offtake. Most of the shovel-ready interregional transmission projects today are merchant projects as shown in **Figure 4**. Nearly all these projects have been designed to connect low-cost remote supply resources to load centers to lower energy costs and meet clean energy goals. Few have been primarily intended to strengthen the reliability and resiliency of the grid.

While merchant projects play an important role in filling the gap while interregional transmission planning processes fail to identify beneficial solutions, an ideal interregional transmission planning process would proactively identify and plan for a transmission system that provides the most widespread benefits.

---

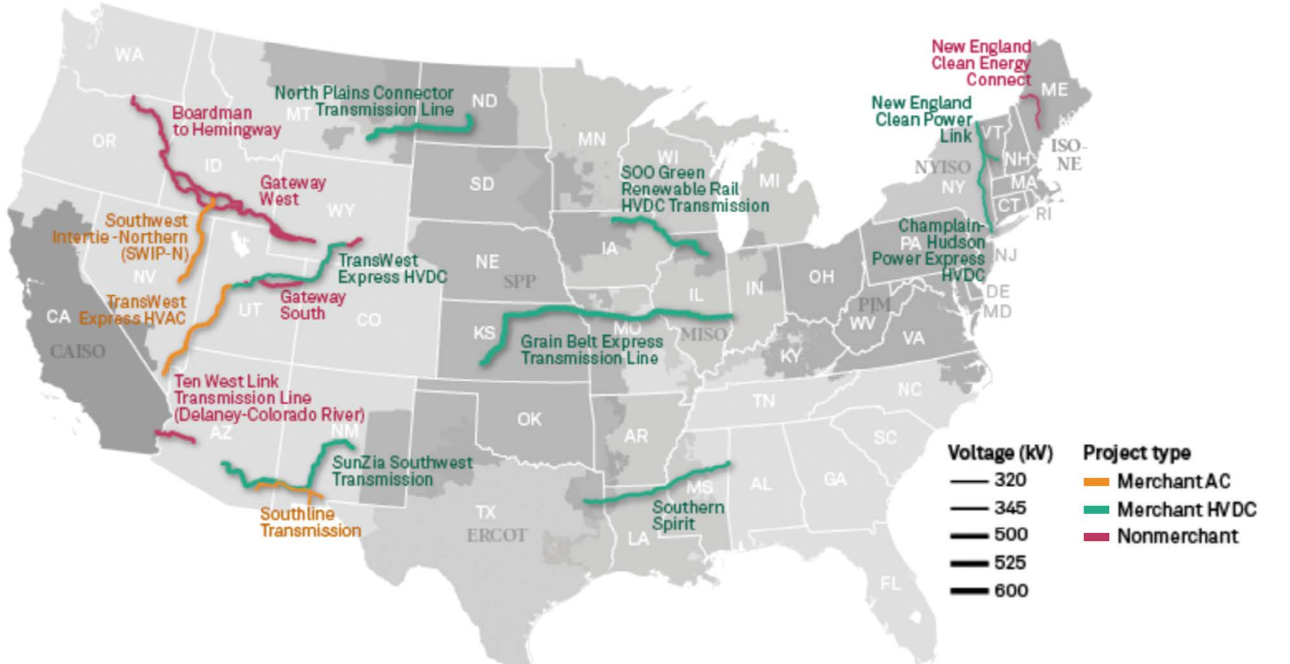
29 R.H. Schulte and F.C. Fletcher, "Why the Vision of Interregional Electric Transmission Development in FERC Order 1000 Is Not Happening," *The Electricity Journal* 33, no. 106773 (2020): 4, https://www.schulteassociates.com/ferc-1000.

30 Organization of PJM States, Inc. and Organization of MISO States, Letter to IPSAC, January 26, 2024, https://opsi.us/wp-content/uploads/2024/02/OPSI-OMS-IPSAC-Letter-20240126.pdf.

31 Federal Energy Regulatory Commission, "18 CFR Part 35: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," April 21, 2022, 35, https://www.ferc.gov/media/rm21-17-000.

32 D. Li, "Do Grid Operators Dream of Electric Seams?: Coordinating Interregional Transmission Stakeholders to Improve Energy Deliverability," *The George Washington Journal of Energy and Environmental Law* 13, no. 1 (2022): 82, https://heinonline.org/HOL/LandingPage?handle=hein.journals/gwjeel13&div=10&id=&page=.

Figure 4. Merchant and Nonmerchant Interregional Transmission Projects as of September 26, 2023[33]



Planning Process Misalignment and Analysis Limitations

Given that regional transmission planning processes are developed independent of one another, it is not surprising that the processes differ in how and when they are conducted. These differences can pose challenges when planning for interregional transmission that spans two or more planning regions. In addition, the methods that are being used today may not be the best methods to capture the value that interregional transmission can offer. This section highlights the challenges with the existing planning process—specifically as it pertains to the technical details behind the analytical process, the misaligned process timelines, and limited accessibility for many stakeholders.

Lack of High-Value Benefits Quantification

Transmission by its nature is multi-value, often providing benefits through investment savings (e.g., generation capital cost savings), operational savings (e.g., reduced production costs), and resilience benefits. Two of the largest drivers of interregional transmission value today are (1) its ability to support decarbonization through access to clean energy resources in other regions (a form of investment savings) and (2) the ability to improve resilience during low frequency, high impact events such as extreme weather events. This section details these two drivers and the lack of valuation methods in most current interregional transmission planning processes to capture these values.

- *Coordinated Transmission and Generation*

  Generation resources are often assumed to be an input to the transmission plans, which by nature requires transmission plans to react to generator locations rather than allow transmission investments to be optimized alongside generation investments.

  This sequential structure inhibits planners from capturing a critical transmission benefit driven by investment savings associated from being able to develop higher quality, lower cost generation resources in locations that would otherwise be inaccessible. This is especially true in the context of aggressive decarbonization policies and goals that require large builds of lower cost, high-quality renewable resources located in

33 Z. Hale, "Merchant Developers Fill 'Void' in U.S. Interregional Grid Build-Out," S&P Global, October 6, 2023, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/merchant-developers-fill-void-in-us-interregional-grid-build-out-76447354.

remote locations. To identify this investment cost savings requires co-optimized transmission and generation planning analysis, typically conducted through capacity expansion modeling.[34]

- *Resilience*

  While many point to increased resilience as a potential benefit of interregional transmission, there is no standard approach to quantify this benefit, and doing so is challenging for multiple reasons. Resilience focuses on a system's ability to withstand and/or recover from "High Impact, Low Frequency" (HILF) events, which generally can be classified in two categories: (1) events that planners are able to hypothesize but struggle to quantify their impact and probability, and (2) events that planners do not hypothesize but may recognize as part of the undefined set of situations that they will be not successful in anticipating until they occur. In both cases, planners lack adequate data and information to render these types of events in electric system planning models and weight their impacts commensurately with their probabilities. Further, even if the reliability impact of interregional transmission during extreme events could be credibly quantified, planners would face the additional challenge of selecting an appropriate value to ascribe to avoided lost load; surveys of the value of lost load often report ranges that span multiple orders of magnitude. Because there is no standard framework to quantify this benefit and the challenges described above, no planning regions have incorporated resilience into quantitative analysis of transmission benefits to date, although this is likely to change with Order 1920 compliance filings. The FERC Order specifically requires planning regions quantify benefits from "Mitigation of extreme events and system contingencies" in their transmission analysis, which will be a measure of production cost savings during simulated extreme events.[35]

Planning Methods

Differences in planning processes and methods among planning entities can lead to those entities reaching different conclusions when analyzing the same project, posing a barrier to coordinated planning and joint decision-making. Key elements of the planning process that can differ from region to region include benefit metrics, process timelines, planning horizons, modeling tools and techniques, and data.[36]

An example of the differences that exist is shown in **Table 1**, which compares key elements of the planning processes in the MISO and PJM regions. Specifically, it compares MISO's Long-Range Transmission Planning (LRTP) process to the Market Efficiency component of PJM's Regional Transmission Expansion Plan (RTEP). The LRTP in MISO is the long-range multi-value transmission planning function of the MISO Transmission Expansion Plan (MTEP), which also includes planning processes for nearer-term reliability-based projects. RTEP's Market Efficiency report is PJM's longer-range economic planning process, which also has a shorter-term reliability-focused counterpart. Currently, the LRTP in MISO and RTEP in PJM are the most forward-looking approach of each region, and both processes satisfy the economic and public policy planning requirements of Order 1000, so are worthwhile to compare in terms of process details and approach. Differences between these two processes can make it difficult to collaborate on planning interregional projects that span the two regions because projects that may be beneficial under one region's methodology may not be under the other region's approach, or the magnitude of estimated benefits may be different across the two regions, which could lead to difficult cost allocation discussions. PJM is actively developing a new Long-Term Regional Transmission Planning Framework, which may provide opportunities to improve coordination and consistency with the LRTP in MISO.[37]

---

34 Capacity expansion models use optimization software to simulate grid conditions and identify portfolios of generation, storage, and transmission resources that minimize total costs (of building out new resources plus operating the system) while ensuring reliability and achieving policy targets.

35 Federal Energy Regulatory Commission, "18 CFR Part 35: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation," 490.

36 R. Garg, Esq, *Electric Transmission Seams: A Primer White Paper*, NRRI Report No 15-03 (Silver Spring, MD: National Regulatory Research Institute, February 2015), 8–9, https://pubs.naruc.org/pub/FA86CD9B-D618-6291-D377-F1EFE9650C73.

37 PJM, "Long-Term Regional Transmission Planning (LTRTP) Framework Update" (Long-Term Regional Transmission Planning Workshop, December 15, 2023), https://www.pjm.com/-/media/committees-groups/workshops/ltrtp/2023/20231215/20231215-item-02---ltrtp-framework-update.ashx.

Table 1. Comparison of MISO LRTP and PJM RTEP Market Efficiency Planning Processes

	MISO LRTP[38]	PJM RTEP Market Efficiency[39]	Difference & Implications
Benefit categories included	1) Congestion & Fuel Savings 2) Avoided Capital Cost of Local Resource Investment 3) Avoided Transmission Investment 4) Resource Adequacy Savings 5) Avoided Risk of Load Loss 6) Decarbonization	1) Energy Benefits (Congestion & Fuel Savings) 2) RPM Benefits (Resource Adequacy Savings)	MISO includes additional benefit categories, including capital cost of local resource investment not shown in PJM; this may risk mismatch.
Calculation of energy (fuel/ congestion) savings	Production Cost Savings	50% * change in production cost + 50% * change in load payment (net of congestion revenue rights held by loads)	Calculation of savings is more heavily weighted to load cost impact in PJM, whereas MISO's production cost test captures generator impact.
Valuation of interregional imports & exports	Imports and exports valued at pool generation-weighted locational marginal pricing (LMP)	Imports valued at load-weighted LMP and exports valued at generation-weighted LMP	Different locational value assigned to interregional transfers.
Production cost model	Promod	Promod	Same software allows for consistency.
Study horizon years	20-year study horizon + 40-year exploration for additional benefits to align with expected lifetime of assets	15-year benefit horizon	Longer study horizon for MISO may show different set of values.
Study model years	3 study years in LRTP Tranche 2: Year 10, Year 15, and Year 20	Four study cases typically at years 6, 10, 13, and 16,[40] with interpolations and extrapolations to supplement	MISO cases study further out years; portfolios are changing over time so potential mismatch.
Discount rate for benefits	6.9% for cost of capital (Also tested with 3% social discount rate)	7.25% historical discount rate	PJM discounts future savings slightly more.
Congestion cost reductions	Reflected only through production cost impact	Included through impact on load costs if unhedged by Congestion Revenue Rights (CRR) holdings by load entities.	Congestion savings in MISO may mismatch with partial hedging of CRRs in PJM.

continued

38 Midcontinent Independent System Operator, "LRTP Tranche 1 Portfolio: Detailed Business Case" (LRTP Workshop, March 29, 2022), 16–54, https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf.

39 N. Dumitriu and N. Rodak, "Market Efficiency Study Process and RTEP Window Project Evaluation Training" (PJM, November, 29, 2022), 10–53, https://www.pjm.com/-/media/planning/rtep-dev/market-efficiency/2022-me-study-process-and-rtep-window-project evaluation-training.ashx.

40 Defined as RTEP Year-4, RTEP Year, RTEP Year+3, RTEP Year+6, with RTEP typically a 10-year case; N. Dumitriu, "Benefit Calculation for Market Efficiency Projects" (PJM, April 20, 2018), https://www.pjm.com/-/media/committees-groups/task-forces/mepetf/20180420/20180420-item-05-benefit-calculation-for-market-efficiency-projects.ashx.

	MISO LRTP	PJM RTEP Market Efficiency	Difference & Implications
Resource portfolio changes	Different renewable generation enabled by new transmission is evaluated compared to a base case with other generators	Consistent generation portfolio evaluated in base case and project case with different operations depending on transmission's impact	PJM economic cases do not show change in resource portfolio in respon se to transmission missing operational and investment savings.
Evaluation of projects	Jointly as a tranche/portfolio of upgrades	Project-by-project basis	Some projects in a portfolio may not pass Benefit Cost Ratio (BCR) if evaluated individually and vice versa.

There are several differences that could cause MISO's LRTP process to find a project to be more beneficial than PJM's RTEP process. For example, LRTP quantifies more transmission benefit categories than RTEP, including avoided risk of load loss, generation and transmission investment savings, and decarbonization. While some benefit categories are likely common to all planning regions, there may be some that are specific to certain regions because they reflect policy preferences for those regions (e.g., decarbonization). For example, MISO includes generation and transmission investment savings (as recommended in the Coordinated Transmission and Generation section above) while PJM does not have a similar category. LRTP also uses a lower discount rate than RTEP at 6.9 percent and 7.25 percent, respectively, causing MISO to place higher value on future benefits relative to PJM. Finally, LRTP evaluates projects on a portfolio basis[41] while RTEP evaluates them on a project-by-project basis. Evaluating projects alongside a portfolio of projects will often result in the net benefits of that portfolio being greater than the sum of its parts, making it more likely for those projects to be approved than if they were evaluated on their own. Portfolios can also be designed to more evenly distribute benefits across the system as opposed to single projects that are more likely to cause disparities in beneficiaries and create pushback as discussed in the Passthrough States section below. Each of these differences could lead LRTP to value projects more favorably than RTEP. This may result in situations where a project that just passes the benefit-cost threshold in LRTP may fail RTEP's evaluation standards, or where the project is beneficial in both regions, but the distribution of benefits varies based on the different approaches, thus impacting cost allocation of the project.

Process Timelines

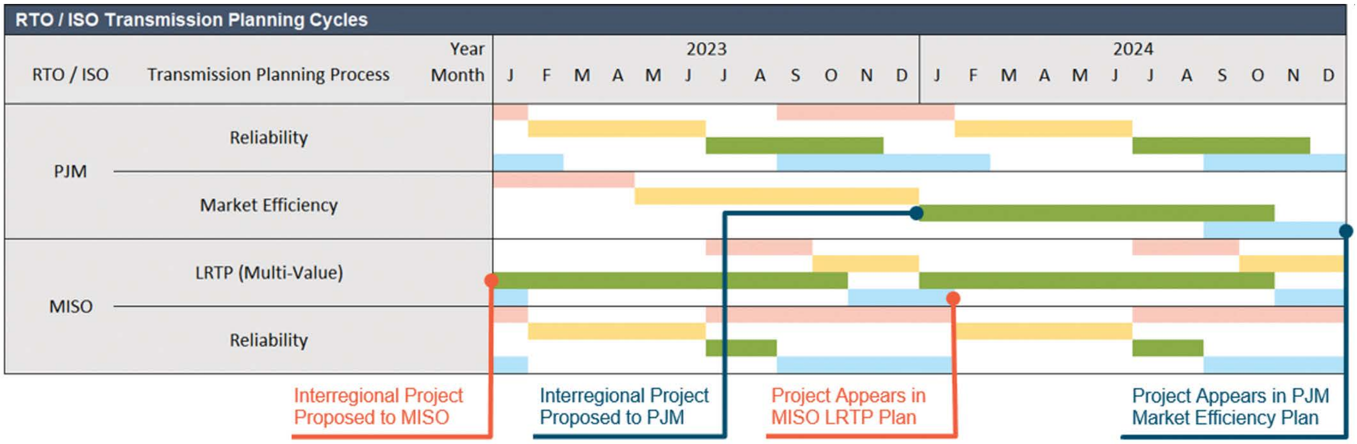
Even if all the discrepancies identified in Table 1 were reconciled, there is often natural misalignment between regions' planning cycles that can inhibit their ability to actively collaborate using existing planning methods. **Figure 5** depicts the reliability and economic planning cycles for PJM and MISO split into four key stages: inputs development, need identification, solution development, and project review and approval.

PJM's Market Efficiency Planning process takes a full two years while MISO's LRTP process takes approximately 18 months, setting up a natural misalignment in planning phases between the two regions. Intraregional planning cycles can also be misaligned, complicating the potential for interregional projects to meet multiple transmission needs. For example, PJM's Reliability and Market Efficiency planning cycles have significantly different planning timelines, making it difficult to plan projects that both meet reliability and economic needs within PJM. Due to the differences in intraregional planning methods depicted in Table 1 and the timelines depicted in Figure 5, if MISO and PJM were to come together to analyze a project, it may require creating an entirely new process separate from their existing planning windows.

41 Portfolio planning is an approach to identifying transmission projects to analyze and approve as a group rather than as individual projects. Portfolio planning captures the potential synergistic impacts of transmission projects, enables planners to capture a breadth of transmission benefits, and can more equitably spread transmission benefits across the grid.

For example, if an interregional project providing economic benefits to both regions was proposed in January 2023, it could enter into MISO's solution development process for the cycle ending in late 2023. The same project would have to wait until the end of 2024 to make it into the equivalent PJM transmission plan. This theoretical project gets delayed a full year due to the misalignment of the two RTOs' planning processes.

Figure 5. Comparison of MISO and PJM Planning Cycles[42, 43]



A similar issue was cited for interconnection timelines for merchant interregional transmission projects. Though merchant projects do not go through planning processes, they still need interconnection approval from each region they cross. In certain cases, a merchant project may receive interconnection approval from one region that expires before they receive approval from another region. These approvals often require the developer to pay transmission upgrade fees; it can be risky for a merchant developer to agree to pay such fees to interconnect with one region without knowing the outcome of the other region's interconnection study.

Technical Nature of Planning

Transmission planning processes are highly technical and are viewed as inaccessible to many interested public parties. As transmission planning processes are typically in the early development stage for potential projects, this lack of accessibility creates another challenge to the efficient buildout of interregional transmission because key stakeholder input is missed early in the process. Interviews indicated that key stakeholders may be unaware of options for proactive participation or that they may otherwise lack the expertise to navigate complex planning practices. Instead, stakeholders may opt to intervene in late-stage siting and permitting processes, delaying and threatening the viability of transmission projects.

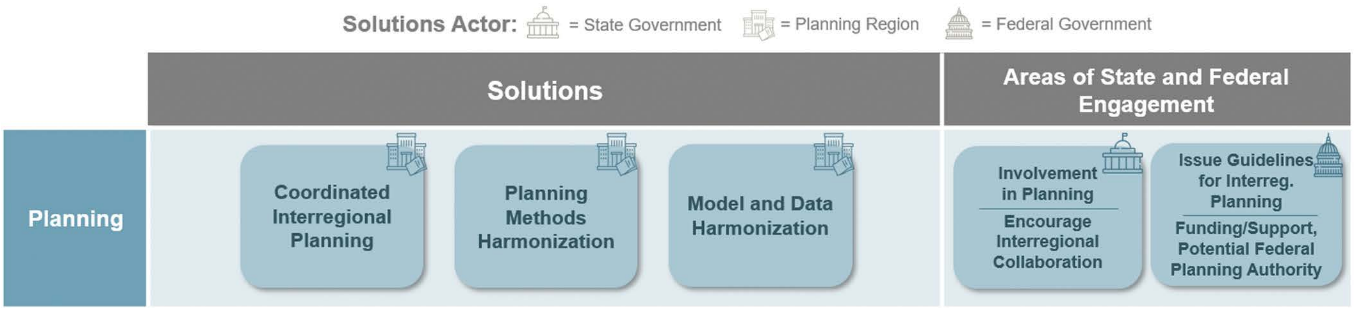
Priority Solutions and Areas of Engagement for Interregional Transmission Planning

Transmission planning processes could work to efficiently identify and approve interregional projects that provide widespread benefits. **Figure 6** presents solutions designed to enable better interregional planning coordination, standardize best practices in transmission planning for interregional planning purposes, and engage state regulators and other key industry stakeholders and decision makers to ensure their diverse needs are reflected in interregional transmission plans. This section discusses these improvements in greater detail.

42 Midcontinent Independent System Operator, "2023 MISO Transmission Expansion Plan," 14, https://cdn.misoenergy.org/MTEP23%20Full%20Report630587.pdf.

43 PJM, "RTEP 2022: Regional Transmission Expansion Plan," March 14, 2023, 78, https://www.pjm.com/-/media/library/reports-notices/2022-rtep/2022-rtep-report.ashx.

Figure 6. Solutions to Planning-Related Challenges



Coordinated Interregional Planning

Summary

Planning regions could expand coordination between planning regions to determine joint transmission needs and identify interregional transmission solutions. To better focus this coordination, planning regions can *identify mutual motivations for coordinating* and *agree upon goals and outcomes* for what they would like to achieve in the coordination process. Collaborative motivation can come from planning regions themselves, from state influence, or requirements and incentives from the federal level.

Solution Actor: Planning Region

Relevant Examples: JTIQ, WestTEC

There was unanimous agreement in the interviews and literature that expanded coordination between planning regions will support better identification of interregional transmission solutions. Areas of coordination discussed included determining joint planning motivators through collaborative needs analysis and harmonizing technical and processes between planning regions. Implementing any new coordination efforts could happen through existing interregional coordination processes or through new, expanded interregional planning processes.

FERC Order 1000 already requires coordination between planning regions. Many of these coordination efforts are between two neighboring regions (e.g., Southwest Power Pool (SPP) and MISO, and MISO and PJM), but several include multiple planning regions (e.g., Independent System Operator-New England (ISO-NE), New York Independent System Operator (NYISO), and PJM; and California Independent System Operator (CAISO), Northern Grid, and West Connect). The extent to which this coordination has resulted in successful interregional transmission projects has varied, as the identification of regional needs that could be served by interregional projects has been limited.

An example of a coordinated planning process that has worked well is the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study.[44] JTIQ was initiated by the MISO and SPP planning regions in 2020 after identifying a planning motivator when each RTO's cluster studies showed that transmission at the seams of the two markets was at capacity, and incremental upgrades required for generator interconnection, particularly high-quality wind, would be too expensive for individual generators to bear on their own. This led MISO and SPP to take an unprecedented step of collaborating to study network upgrades at their market seams that would be more cost effective than the upgrades identified in their respective regional processes.

JTIQ evaluated transmission projects individually and as a portfolio using an adjusted production cost benefit metric. Based on the modeling results, the study identified a portfolio of seven projects costing nearly $1.7 billion that could enable up to 53 gigawatt (GW) of new resources to be interconnected along the MISO-SPP seam.[45]

44 Midcontinent Independent System Operator and Southwest Power Pool, "Joint Targeted Interconnection Queue Study: Executive Summary," March 2022, https://www.spp.org/documents/66725/jtiq%20report.pdf.

45 Midcontinent Independent System Operator and Southwest Power Pool, "Joint Targeted Interconnection Queue Study," 2, 7.

Nearly two years after completion of the study, MISO and SPP are still working to determine cost allocation of these projects, highlighting the complexity of interregional cost allocation.[46]

The JTIQ process depicts important elements of success to consider when designing future coordinated interregional transmission planning approaches, specifically: identifying a planning motivator to foster coordination (e.g., address limitations to interconnecting resources along the seam) and executing coordinated technical studies by each RTO.[47] In addition, the JTIQ process employed a robust stakeholder engagement process to ensure feedback from both internal and external stakeholders could be incorporated into the study. Each of these elements addresses a challenge to interregional transmission planning today—finding a planning motivator, harmonizing the planning process, and incorporating stakeholder feedback.

Although JTIQ is one of the best examples of interregional transmission planning to date, more could be done to enable beneficial interregional transmission planning. First, JTIQ was motivated by MISO and SPP identifying a need for expanded transmission capacity through their independent transmission planning processes. While this helped provide clear motivation to conduct the study, it may have undervalued selected solutions because they weren't being evaluated for how they meet any other system needs. Second, only using adjusted production cost as the benefit may also lead to undervaluing transmission for its investment cost savings and resilience benefits discussed in the "Lack of High-Value Benefits Quantification." And finally, while the technical studies were coordinated across MISO and SPP, each RTO used their own models for the analysis, which included differences in how data and assumptions were used for the analysis. These differences in analysis can introduce discrepancies in study results across the RTOs, leading to potentially even more complication during cost allocation.

Joint identification of needs through forward-looking, multi-value approaches rather than through individual transmission region identification of needs like in JTIQ, could lead to identification of more beneficial interregional transmission projects. This more expansive approach would centralize planning a step further by aligning processes at the needs identification stage and would benefit from a single planning model and data set to ensure consistency. Bringing interregional transmission planning under a unified umbrella also overcomes many of the challenges posed by interregional projects navigating incongruent planning practices across regional entities. It would also enable third-party developers to propose interregional transmission solutions without having to circumnavigate currently fractured planning and interconnection processes.

Though still in early stages of development, the Western Power Pool's Western Transmission Expansion Coalition (WestTEC) is an example of an interregional transmission planning process which encompasses many of the enhanced planning elements identified above. It is Western Interconnection-wide, including the footprints of the three transmission planning entities in the region, and borne out of a recognition that more holistic and coordinated planning than current planning processes was required to meet the needs of a future grid.[48] Key differentiators of WestTEC from Order 1000 planning, outside of footprint, include:[49]

- Forward-looking planning that identifies regional and interregional needs and considers an expanded set of benefits metrics;
- Voluntary effort that is not compliance-driven;

46 Midcontinent Independent System Operator, "JTIQ Cost Allocation" (RECBWG, January 23, 2024), https://cdn.misoenergy.org/20240123%20RECBWG%20Item%2002a%20Cost%20Allocation%20Update631435.pdf.

47 Midcontinent Independent System Operator and Southwest Power Pool, "Joint Targeted Interconnection Queue Study," 4.

48 Western Powerpool, "Western Transmission Expansion Coalition Concept Paper for a West-Wide Transmission Plan," October 2023, 3, https://www.westernpowerpool.org/private-media/documents/Western_Transmission_Planning_Concept_Paper_October_2023.pdf.

49 WestTEC, "Western Transmission Expansion Coalition: WestTEC" (Public Webinar, January 29, 2024), 7, https://www.westernpowerpool.org/private-media/documents/WestTEC_Public_Webinar_1_29_24.pdf.

- Broad participation from key stakeholders outside of transmission owners, including central participation from states and tribes, in the scoping of the process, governance, and technical analysis; and
- Focus on benefit and cost estimation but not on determining cost allocation.

Though the outcomes of the WestTEC process are yet to be seen, the elements of successful planning coordination appear to be embedded within the process as designed to date and will be a good process to track as it develops further.

Planning Methods Harmonization

Summary
Regions could *standardize best practices* in transmission planning to ensure the best available projects are being identified, thoroughly analyzed, and have their costs fairly allocated to reduce friction in interregional collaboration. *Harmonizing planning approaches and timelines* would enable efficient interregional collaboration and allow projects to avoid delays due to asynchronous planning processes.
Solution Actor: Planning Region
Relevant Examples: Best practices and benefit metrics detailed in Order 1920

Planning processes are complex, time-intensive, and vary widely between planning entities, making it difficult to propose a transmission project that will satisfy requirements of multiple regions. The recent FERC Order 1920 entitled "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation" (Order 1920) require that planning entities use certain best practices, providing guidance that would standardize certain elements of the planning framework in a manner that supports interregional planning. Specifically, Order 1920 includes the following items:

- Requires planning regions use a minimum 20-year planning horizon to combat undervaluation of transmission projects from modeling horizons that are significantly shorter than transmission project lifespans.
- Defines a broad set of transmission benefit metrics (see list below), some mandatory and some optional for use in transmission evaluation, in an effort to combat undervaluation of transmission solutions.
- Requires regions to conduct scenario-based transmission planning to encourage planners to anticipate how potential changes in projected grid conditions impacts modeling results and select solutions that are resilient to those changes. Scenarios serve to inform planners of how to adapt to potential future conditions that may play out differently from their assumed modeling baseline.[50]
- Allows but does not require the use of transmission *portfolios* rather than *individual projects*. Portfolios of multiple projects can be designed to spread transmission benefits equitably across beneficiaries rather than individual projects that tend to serve specific load centers while creating potential opponents from project hosts and other stakeholders.[51]

---

50 Order 1920 requires that planning regions use at least three scenarios based on some or all of the following factors: (1) federal, state, and local laws and regulations that affect the future resource mix and demand; (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load-serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand; Federal Energy Regulatory Commission, "18 CFR Part 35: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation," 324.

51 The Notice of Proposed Rulemaking that preceded the final Order 1920 considered requiring the use of portfolio-based planning but ultimately decided against the requirement for a number of reasons, including concerns about delays, portfolios masking individually poor-performing projects, and others; Federal Energy Regulatory Commission, "18 CFR Part 35: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation," 413.

- Requires planning regions to make a good faith effort to consult with and seek support from relevant state entities when establishing transmission evaluation processes and selection criteria for long-term transmission projects. This effort enables states to voice their transmission needs and articulate any state-specific barriers to permitting and siting so planners can attempt to design the transmission system to be most beneficial for all states involved. The order does not require regions formalize a process for said coordination and its "good faith effort" language does not require express approval from state entities before finalizing evaluation processes, selection criteria, or cost allocation decisions.

The ruling goes a long way to align planning processes but could be further bolstered. Options include expanding the set of benefit metrics that must be analyzed, thereby standardizing benefit valuation across planning regions. The benefit metrics listed as either mandatory or optional in Order 1920 are listed below.

Transmission Benefits in FERC Order 1920[52, 53]

- Required Benefit Metrics
  - Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement,
  - Reduced loss of load probability or reduced planning reserve margin,
  - Production cost savings,
  - Reduced transmission energy losses,
  - Reduced congestion due to transmission outages,
  - Mitigation of extreme events and system conditions, and
  - Capacity cost benefits from reduced peak energy losses.
- Optional Benefit Metrics
  - Mitigation of weather and load uncertainty,
  - Deferred generation capacity investments,
  - Access to lower-cost generation,
  - Increased competition, and
  - Increased market liquidity.

Model and Data Harmonization

Summary
Planning regions could strive to *reconcile differences in modeling techniques, tools, and benefit calculation methods* to enable streamlined collaboration on interregional transmission analysis.
Solution Actor: Planning Region
Relevant Examples: WECC Anchor Data Set

Models and data sets are critical elements for identifying transmission projects with consistency. While planning regions may use the same type of model (e.g., production cost model) to evaluate transmission value, there are differences in how different software platform algorithms (e.g., PLEXOS, Gridview) are structured, which can lead to differences in study results. Similarly, utilizing different input data for studies can lead to

52 Federal Energy Regulatory Commission, "18 CFR Part 35: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation," 536.

53 Several studies as well as comments on the FERC Notice of Proposed Rulemaking that preceded Order 1920 identified additional benefits that extend beyond the list of transmission benefits identified within Order 1920; Federal Energy Regulatory Commission, "18 CFR Part 35: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation," 601.

different outputs. Harmonizing the model platforms and data utilized is a step toward allowing for more easily coordinated planning. Planning regions could share long-range planning models or even collectively update a master planning model to increase planning transparency and limit uncertainty about future grid conditions. An example of a shared data set is the Western Electricity Coordinating Council (WECC) Anchor Data Set (ADS) utilized by planning entities in the West.[54] It is a database of key inputs, including loads, resources, and transmission topology, to power flow and production cost models that is regularly updated by utilities and Balancing Area Authorities in the West. It is reflective of 10-year projections of grid conditions in line with state energy policy goals and utility integrated resource plans. The ADS is a key element of planning among entities in the West and ensures a common foundation for planning work.

A particular area of importance for data harmonization is for weather-dependent time-series data. Since weather-driven diversity is often an important driver of interregional transmission benefits, it is important to account for that diversity as accurately and consistently as possible. An example of successful support of data harmonization is NREL's development of the data used for the *Western Wind and Solar Integration Study*[55] and subsequent work, which provided a public source of weather-synchronized hourly output of existing resources as well as the potential output that could be expected if wind or solar resources were installed at a particular location. This data enables comparisons of hourly output from both existing resources and portfolios of new resources across regions that interregional transmission could connect.

Areas for State-Level Engagement

Summary
State entities should be actively *involved in regional and interregional transmission planning* processes to advocate for transmission plans to meet their state-specific needs. States should use their influence to *advocate for more effective interregional planning* efforts.
Examples: MISO's MVP projects, New York-New England Interregional Project

States are some of the most influential stakeholders in transmission planning venues. As transmission permitting largely falls within state jurisdiction, the best laid transmission plans can come to a halt if states are not on board. Several of our interviewees underscored the importance of state engagement during the planning process to ensure that state interests are represented, particularly during the transmission needs identification stage.[56] Ensuring regional planners are attuned to the needs of states can support the development of planning motivators that can facilitate successful interregional coordination, as well as help promote transmission plans that will specifically reflect the information state regulators will need to make informed permitting decisions. One transmission planning entity interviewed highlighted the importance of state participation in their planning process, as it led to successful permitting decisions of projects in those states.[57]

There is a rich history of successful state engagement in transmission planning that highlights the value of including states not only for the planning outcomes, but also in the planning process development. For example, state governors and regulators played an active role in fostering the development of MISO's Multi-Value Project

54 WECC, Anchor Data Set (ADS), https://www.wecc.org/ReliabilityModeling/Pages/AnchorDataSet.aspx.

55 GE Energy, *Western Wind and Solar Integration Study* (New York, NY: U.S. Department of Energy, the National Renewable Energy Laboratory, May 2010), https://www.nrel.gov/docs/fy10osti/47434.pdf.

56 FERC Order 1920 will require transmission planning regions to consult with state entities as they develop methodologies for evaluating and selecting transmission solutions; Federal Energy Regulatory Commission, "18 CFR Part 35: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation," 697. States could be proactive in further defining how this consultation will happen so that their most important priorities and concerns are recognized early in the planning process.

57 State participation in planning processes should be limited to ensuring their needs are met and local siting and permitting challenges are avoided. It should stop short of advocating for specific projects to protect their unbiased position in permitting decisions.

(MVP) planning process in 2012.[58] A key action that supported the development of the MVP process was the creation of the Upper Midwest Transmission Development Initiative (UMTDI) by five Midwest governors[59] in 2008 to tackle regional transmission planning and cost allocation issues associated with renewable delivery across their states. The initiative was made up of a bipartisan mix of gubernatorial staff and commissioners from their respective state commissions, but also had extensive support from MISO.

The strong relationship that developed between UMTDI and MISO flowed through to MISO's Regional Generation Outlet Study (RGOS), which aimed to identify transmission portfolios to meet MISO member states' RPSs at the lowest cost. Through the RGOS, UMTDI members advocated for local economic development and job creation needs, which resulted in a more balanced distribution of wind modeled across the MISO footprint.[60] These wind zones were then used as the basis for various transmission expansion scenarios to understand which scenarios delivered the lowest cost energy across the footprint. The RGOS process consulted states regularly through both UMTDI members' participation in RGOS as well as briefings between MISO senior leadership and state governors. These briefings allowed for sharing of study results and created space for governors to provide input, ask questions, and raise any concerns. The support RGOS raised through the consultative approach fostered trust among states in exploring long-term transmission strategies. Ultimately, MISO identified a subset of transmission projects from RGOS, as well as other studies, to use as part of a candidate MVP portfolio analysis, which resulted in the recommendation to move forward with 17 transmission projects[61].

Given the precedent for their active participation in transmission planning, state government officials and regulators could work together to develop a common agreement on the need for interregional transmission and encourage planning regions to engage in more productive interregional transmission solution identification. This coordination effort could make use of existing platforms for state regulators to interact with regional planning authorities like SPP's Regional State Committee, the OMS, the OPSI, and others. Coordination forums could be supported by best practices and funding opportunities established by the federal government and discussed in the subsequent section.

Another salient example of state level engagement in identifying interregional transmission solutions that align with state policy objectives can be found in the Northeast United States, where New England states and New York worked cooperatively with National Grid, a transmission owner, to examine the benefits of investment in coordinated upgrades of lines comprising the NYISO–ISO-NE intertie.[62] This collaborative effort developed out of an asset condition need identified by National Grid, the transmission owner on the New England side of the interface, and was done outside of the traditional transmission planning processes for both regions.

As upgrades to the associated system infrastructure were examined, it became clear that both regions could experience greater benefits if the entire interface was comprehensively upgraded, prompting a cooperative effort between the two regions to quantify the potential mutual benefits, including but not limited to the potential for the upgrade to support the achievement of future state clean energy policy goals across the Northeast region. Ultimately, the effort found that the proposed upgrades to the interregional transmission intertie would result in combined operational cost savings of more than $1 billion on a present value basis across New York and New

---

58 Midcontinent Independent System Operator, "2011 MVP Portfolio Analysis Full Report," 3, https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf.

59 States included Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin.

60 D. Boyd and E. Garvey, "A Transmission Success Story: The MISO MVP Transmission Portfolio" (St Paul, MN: AESL Consulting, November 8, 2021), 16, https://www.aeslconsulting.com/wp-content/uploads/2021/11/MISO-MVP-History.pdf.

61 Midcontinent Independent System Operator, "2011 MVP Portfolio Analysis Full Report," https://www.misoenergy.org/planning/multi-value-projects-mvps/#nt=%2Fmultivalueprojecttype%3AMVP%20Analysis%20Reports%20(2011)&t=10&p=0&s=Updated&sd=desc 2.

62 Executive Office of Energy and Environmental Affairs, Massachusetts Department of Energy Resources, and

England.[63] Further, increased carrying capacity of one GW from the upgrade would reduce curtailment and congestion in load zones across both ISOs, improving the path for alignment with regional energy policies.

This collaborative effort illustrates the ability for state agencies to guide transmission solution identification to meet multiple needs when traditional planning pathways may be otherwise unavailable due to their preference for evaluating reliability and economic needs separately. Further, while federal incentives were not a direct consideration in undertaking this collaborative effort, the presence of financial support catalyzed action and compelled more earnest engagement of all parties throughout the process.

Areas for Federal-Level Engagement

Summary

The federal government could *provide funding and issue guidelines for interregional planning* for coordinating transmission planning processes and technical analysis processes. The federal government could also fund continued development of robust underlying weather-dependent data that enable planning processes to best incorporate the impact of interregional diversity. Some have also discussed the potential for a *federal transmission planning authority*.

If planning regions and states coalesce around increased coordination for interregional transmission planning, there will be a need for resources to support the development of coordinated data, models, and processes. This is an area where the federal government, through DOE and/or FERC, could provide guidelines, best practices, and technical forums to facilitate information sharing and support the development of harmonized data, models, and processes. Given the many objectives that states are trying to balance with limited resources, federal funding to support training or hiring of additional staff to support participation in the enhanced planning efforts could also be beneficial.

Finally, high-quality weather-dependent data synchronized over a wide geographic area is costly to develop and often difficult to access and manage. Federal resources are well suited to further develop weather-driven time-series data that enable planning processes to more easily and accurately identify potential benefits of interregional diversity. This extends both to increasing data granularity and characterization of the frequency and impact of extreme weather events, as well as to estimation of likely "forecast error" in predicting the resource output and load levels at a given location.

Similarly, for resilience analysis, additional federal support could help form a more consistent basis for interregional planning studies by further developing underlying data that characterize (1) the probability of customer outages due to extreme events and (2) the cost of those outages over different durations.[64] Federal efforts in this area could promote more standardization across regions, as well as benefit from economies of scale by evaluating infrequent outage events over a wider geography.

If states and planning regions make only limited progress in enhancing interregional planning processes going forward, there is the potential for the federal government to engage in planning more directly through the establishment of a federal transmission planning authority that assumes transmission planning responsibilities of the current planning regions. This could be disruptive and would require federal preemption through an act of Congress. While it should not be the leading option for federal engagement, it is an option that could be called upon in the event of no progress at the state and planning entity level.

63 Federal Funds & Infrastructure Office, "New England States Seek Federal Funding for Significant Investments in Transmission and Energy Storage Infrastructure," April 17, 2024, https://www.mass.gov/news/new-england-states-seek-federal-funding-for-significant-investments-in-transmission-and-energy-storage-infrastructure.

64 There are tools, such as the Interruption Cost Calculator (ICE) available through LBNL, that quantify loss of load over short periods, but these values could use more recent updating (2018 was the last update) and expansion, including longer duration outages as well as probability estimates.

Interregional Transmission Permitting

Once a project is awarded development rights at the end of the transmission planning process, it moves on to the siting and permitting processes. Siting is the process of determining and approving the route a transmission line will take. Here, we refer to permitting as the process of deciding whether a project is in the public interest and issuing a permit that codifies approval, such as through a CPCN and is generally conducted by state regulators.[65] These two processes (siting and permitting) are often referred to together, because they are often conducted by the same entities and permitting decisions are contingent upon findings of the siting process.[66] Given siting and permitting occurs at the end of the project's development process, state regulators typically have the final decision over which transmission projects are built.[67]

While the planning of interregional transmission projects takes place at the system level (which is multi-state), projects must apply for permitting at a state level. Permit applications are independent and unconnected across states. In practice, there is a wide range of how these proceedings are conducted from state to state, although they almost always require determination of project need and demonstration of how the project serves the public interest. These permitting proceedings are also venues for stakeholders to participate, and oftentimes oppose transmission projects, as they address challenging issues such as impacts to landowners, communities, the environment, and costs.

The application requirements for permits vary by state, but it is common for project developers to submit benefit cost analyses to demonstrate how projects benefit each state. In addition, discussion of the following topics is often included:

- Economic activity including construction and maintenance,
- State and county income from taxes,
- Landowner impacts, including land value, right-of-way issues, and environmental risks, and
- Electricity rates.

State regulators do not generally have a standard set of benefits they require to be evaluated, but it is common for states to have different priorities for how a project may serve the public interest. For example, a state with a carbon reduction goal may want to ensure that interregional projects do not import incremental greenhouse gases to the state.

Timelines for permitting processes are rarely coordinated between states, which can lead to project development delays. For example, the Arizona Corporation Commission makes a permitting decision within 180 days of receiving a complete application while the neighboring California Public Utilities Commission (CPUC) has a limit of 18 months with exceptions for particularly contentious projects. Projects must be successful in obtaining permits in all states in which they intend to construct. This requires a fair amount of coordination by the project developer to engage in multiple permitting proceedings and ensure project application information remains current and tailored to each state.

65 This section does not address additional state or federal permits that may be required to construct transmission lines, such as environmental permits.

66 Interregional projects may require siting on federal land, which requires siting approvals from federal agencies. These approvals generally need to be complete before permits from state regulators can be issued.

67 Which transmission projects require state permits differs across states. Generally, most states require permits for high voltage transmission (200 kV and above).

Challenges with Interregional Transmission Permitting

Permitting processes can pose significant barriers to building beneficial interregional projects. These challenges come from limited resources at permitting agencies, differences between permitting processes, and difficulties in meeting permitting criteria across every state through which an interregional project passes. This section discusses these challenges.

Redetermining Project Need

Most permitting approvals require a justification of the necessity of the transmission project. This often requires an assessment of project benefits and costs. This can be seen as duplicative for projects that have already obtained approval through a regional transmission planning process. This redetermination of need through the permitting process can sometimes be construed as "another bite at the apple" for issues that were already addressed during the planning process, or present new questions related to need that were not in scope during the planning process. Iteration on these issues of need can sometimes lead to permit denials or project reconfigurations to address the need identified within the permitting proceeding; both outcomes are not ideal and highlight the challenges of replicated need determinations in planning and permitting.

Interregional projects face challenges from misaligned planning processes across regions and non-harmonious state permitting processes. The journey through these two key levels of regulatory approvals is further complicated by the fact that regional planners and state permitting entities often do not adequately communicate with each other and strive for projects to provide net benefits at fundamentally different scales. Planners focus on the regional scale while states focus on ratepayer impacts within state borders. This disconnect between system and state planning can lead to projects that are beneficial from a system perspective failing to achieve state-level regulatory approval, either because planners were unaware of state-specific needs and siting challenges or because of incompatible benefit propositions between planning regions and states.[68]

State permitting entities are often limited in their ability to participate in transmission planning and analysis. Multiple interviewees mentioned that their permitting entities are understaffed, underfunded, and spread thin across their many regulatory responsibilities. If unable to participate in the transmission planning process, they may not be able to advocate for their energy needs to be reflected in proposed projects or warn against local siting challenges. Interregional transmission projects are then planned without their input, which can result in the denial of the permits and ultimately, project delays or cancellations.

Passthrough States

Planners identify projects that can provide net benefits across the region while state permitting entities only assess the net impacts to the ratepayers within their state. Our research findings highlighted that these different perspectives come to a head when states that will host a transmission project do not directly receive project benefits and when states perceive that they will be impacted to enable other states' energy priorities. These states—often referred to as passthrough states—were frequently mentioned as a barrier to successful interregional transmission development. Despite not being allocated transmission costs, the passthrough state's permitting authorities may perceive other costs to their ratepayers due to the physical impacts of transmission projects.

---

68 In certain instances, this challenge not only applies to interregional projects, but has also delayed development of projects inside a single RTO region. For instance, the Transource transmission project received FERC approval of PJM's cost allocation methodology but then was rejected permits by the Pennsylvania PUC due to a perceived lack of benefit for the ratepayers of Pennsylvania. A district court recently rejected the Pennsylvania PUC's claim, asserting that (1) the Supremacy Clause indicates that FERC's determination that the project is in the public interest invalidates a state law that interferes with the federal decision and (2) the Dormant Commerce Clause indicates that, since the Transource project is regionally beneficial, the PUC's decision is invalid because it imposes restrictions at out-of-state interests' expense. The case is pending appeal, and it is an open question as to the application of this case going forward and its impact on the ability of states to find that a project is not in their ratepayers' best interests if regional cost allocation was approved by FERC; J. Elkin, "Federal Court Limits State Authority to Deny Interstate Transmission Projects," Climate Law blog, Columbia Law School, Sabin Center for Climate Change Law, January 22, 2024, https://blogs.law.columbia.edu/climatechange/2024/01/22/federal-court-limits-state-authority-to-deny-interstate-transmission-projects/.

The passthrough state challenge is illustrated by the Missouri Public Service Commission (PSC) order denying permits to the interregional merchant project, Grain Belt Express. The developer's demonstration of public necessity hinged upon both enabling Missouri to meet wind energy targets and aiding Kansas wind to reach load centers east of Missouri. The Missouri PSC stated that it was more "appropriate to consider aspects of the project related to the effect on Missouri utilities and consumers rather than how it might affect Kansas wind developers or utilities and consumers from other states."[69] This simple statement nullified one of the Grain Belt Express's key arguments for public necessity, contributing to the permit denial and illustrating the challenges faced by a project designed to bring system-wide benefits when isolating net impacts for permitting approval in a passthrough state. It should be noted that Grain Belt Express was able to successfully obtain a permit from the Missouri PSC after more clearly providing evidence for the financial and economic benefits to Missourians, having secured offtake agreements from a coalition of Missouri municipalities and expanded its eminent domain offer to landowners for 150 percent of fair market value.[70]

Priority Solutions and Areas of Engagement for Interregional Transmission Permitting

Permitting processes could be improved by bolstering state capabilities to assess transmission benefits and evaluate transmission projects. This can enable more streamlined permitting decisions, empower states to anticipate and advocate for their own transmission needs, and coordinate across permitting agencies. This section discusses solutions shown in **Figure 7** that are designed to help achieve these kinds of permitting improvements.

Figure 7. Solutions to Permitting-Related Challenges

State Transmission Authorities

Summary

State funding of *special agencies* to engage in transmission planning activities, analyze transmission needs, provide siting guidance to developers, and participate in or even fund transmission development.

Solution Actor: State Government

Example: New Mexico Renewable Energy Transmission Authority

69 "Before the Public Service Commission of the State of Missouri: File No. EA-2014-0207. Report and Order," 2015, https://psc.mo.gov/CMSInternetData/ON/Orders/2015/070114207.htm.

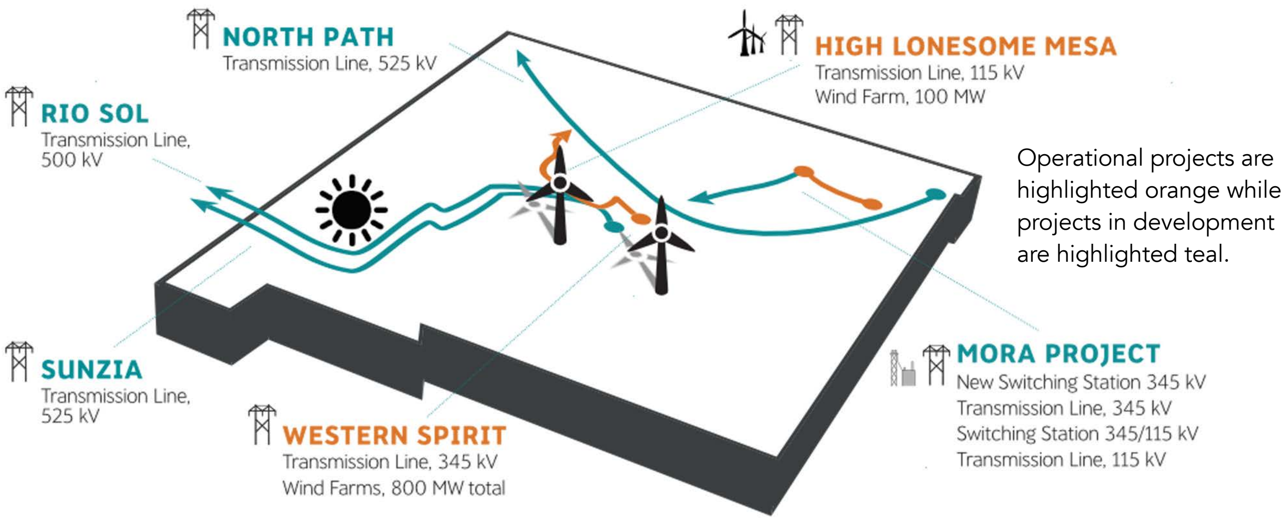
70 E.L. Reiher, "Property Over Planet: How the Grain Belt Express Sparked Utility Eminent Domain Reform in Missouri," *Missouri Law Review* blog, June 12, 2023, https://law.missouri.edu/lawreview/2023/06/12/1958/.

Several states have established transmission authorities independent from regulatory agencies that have been tasked with facilitating transmission development within and between their state and neighboring states.[71] While each transmission authority has its own roles and responsibilities, examples of the types of roles they can fill include:[72]

- Engage in transmission planning activities,
- Identify transmission corridors including interstate corridors with neighboring states,
- Provide oversight of right-of-way acquisitions between developers and landowners,
- Exercise eminent domain where necessary,
- Issue and sell bonds to develop projects, and
- Enter into partnerships with public or private entities to support or develop projects.

These dedicated state agencies can provide targeted support for transmission development and can potentially be the voice of the state in the planning region discussions.[73] The on-the-ground expertise that the authorities bring to development is quite important as well, given the delays in transmission development often occurs during siting and permitting.[74] For example, New Mexico's Renewable Energy Transmission Authority (RETA) works with both landowners and developers and provides balanced oversight during the right of way acquisition process. This allows landowners to receive at least fair market compensation for their land and ensures the developer can get their project built. This can reduce time for overall project development as demonstrating control of right of ways is often a key criterion to obtaining a permit.[75] Direct investment in projects can also be helpful, particularly if cost allocation discussions are not successful or are stalled. The co-sponsorship of projects by state transmission authorities can bring credibility to a project that can increase its chances of development success as well. RETA has several public-private partnerships with interregional transmission projects (Sun Zia and Rio Sol) as depicted in **Figure 8**.

Figure 8. New Mexico Renewable Energy Transmission Authority Public-private Partnerships[76]



71 Several state transmission authorities were established in the mid-2000s in the Great Plains and Rocky Mountain West in response to growing attention on transmission and wind development at the time. Several of these have evolved to explore transmission needs and alleviate current challenges beyond wind integration; Americans for a Clean Energy Grid, "Transmission Time: The Role of State Transmission Authorities" (event recording, October 26, 2023), https://cleanenergygrid.org/event/transmission-time-the-role-of-state-transmission-authorities/.

72 Example roles and responsibilities are drawn from state transmission authorities in Colorado, New Mexico, and North Dakota.

73 This particular function can also be conducted by state regulators.

74 Permitting delays can come from redetermination of need and other intra-state challenges, but they can also occur when projects cross onto federal and tribal land, requiring permits from external permitting agencies.

75 New Mexico Renewable Energy Transmission Authority, "For Landowners," https://nmreta.com/resources/#landowners.

76 New Mexico Renewable Energy Transmission Authority, "Transmission Lines: Creating a Highway for Clean Energy," https://nmreta.com/transmission-lines/.

Host Community Benefits

Summary
Projects could be designed to provide *non-energy benefits to host communities* to ensure states that bear the physical impact of a project also receive benefits. These benefits can include providing jobs and job training, revenue sharing, and investment in capital projects, social programs, and economic development opportunities.
Solution Actor: Planning Region and/or State Government
Example: NYSERDA's Tier 4 REC's solicitation

Projects could avoid the passthrough state conundrum or host community opposition by creating new ways for host communities to benefit. Impacted communities could be given compensation in the form of project equity, direct financial payments, or infrastructure investments like schools and roads. States could also investigate whether it would be appropriate to provide greater landowner compensation than what is typically provided under eminent domain. These types of financial benefits must be carefully designed to avoid being exploited.

One example of a state that explicitly valued non-energy community-based economic benefits of transmission projects was New York State's Tier 4 Renewable Energy Credit (REC) procurement administered by the New York State Energy and Research Development Authority (NYSERDA).[77] The Tier 4 REC program sought to procure RECs from projects that used long-range transmission to provide zero-carbon energy to New York City. Though these projects were not identified through traditional transmission planning methods, states, developers, and planning regions can learn from their approach of finding projects that provide non-energy community-based benefits. In their solicitation for Tier 4 projects, the NYSERDA's evaluation criteria weighted 10 percent of their bid evaluation on a category they called the Incremental Economic Benefits Plan. This category requires proposals to detail plans for job creation, workforce development, and investment in non-transmission infrastructure and community economic development. The list below contains options of community-based economic benefits bidders can include in their Incremental Economic Benefits Plan.[78] New York ended up selecting two projects in Clean Path NY (CPNY) and Champlain Hudson Power Express (CHPE), shown in **Figure 9**, that promise to provide $460 million in community investment funds, 10,000 new jobs, and $8.2 billion in economic development investments.[79]

NYSERDA Tier 4 Eligible Incremental Economic Benefits Options[80]

- Long-term employment of New York workers;
- Establishment of a project office in New York State;
- Purchases of materials sourced within New York;
- New or increased local property tax payments to school districts, cities, towns, etc.;
- Host community payments, mitigation or conservation payments, or other funds that will directly benefit host communities;
- Any premium purchase payments and payments for leases of land in New York above market value;
- Hosting of local internships and programs for students in renewable energy education in partnership with local school systems/NGOs/foundations;
- Hosting of clean energy sector occupation apprenticeships or training programs; and
- Hosting of environmental justice programs.

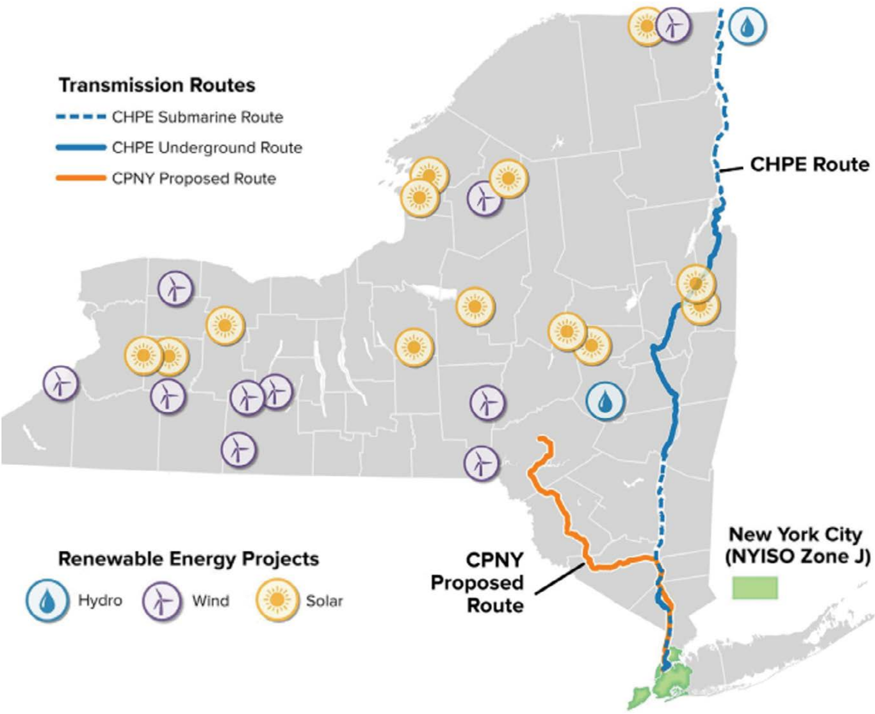
77 New York State Energy Research and Development Authority, "Tier 4 – New York City Renewable Energy," https://www.nyserda.ny.gov/All-Programs/Large-Scale-Renewables/Tier-Four.

78 New York State Energy Research and Development Authority, "RFP, Appendices and Schedule" (2021), 57, https://www.nyserda.ny.gov/All-Programs/Large-Scale-Renewables/Tier-Four/Solicitation-and-Award/RFP-Appendices-and-Schedule.

79 New York State Energy Research and Development Authority, "Tier 4 – New York City Renewable Energy."

80 New York State Energy Research and Development Authority, "RFP, Appendices and Schedule," 58–59.

Figure 9. New York State Tier 4 Renewable Energy Projects[81]



An example of project investment in host communities that may otherwise oppose the project is CHPE's investments in the Haverstraw Bay area. The community will be significantly impacted by construction activities, as CHPE will cross through Haverstraw Bay's central business areas when it is undergrounded. In recognition of the inconvenience, CHPE is working with the community to minimize business and aesthetic impacts and is investing a total of $31 million into street improvements and an investment fund used at the discretion of local government on capital projects.[82] CHPE is also co-owned by the Mohawk Council of Kahnawà:ke, a Canadian First Nation and host community of the project.[83]

As seen in New York, clarifying intent to evaluate nontraditional transmission benefits can prompt developers to provide these community benefits and work with host communities to address the physical and financial impacts of interregional transmission projects.

Streamlined Need Determination Across Planning and Permitting Processes

Summary
The planning process for interregional transmission projects includes a project impact assessment that is constructive to the needs determination included in the permitting process. *Streamlining the planning and permitting process to rely on the same analysis* could speed up the determination of public need.
Solution Actor: State Government
Example: California's rebuttable presumption

Redetermining need in the permitting process can often be challenging, as it may require developers, who have already been awarded development rights through the regional planning process, to duplicate analytical efforts to engage in state-level permitting proceedings. While there may be times where redetermining need is appropriate—such as if a long period of time has lapsed from when need was determined in the planning process or system conditions have materially changed—it would be useful to use the planning region's need determination for the state permitting process. This solution is particularly effective when states actively

81 New York State Energy Research and Development Authority, "Tier 4 – New York City Renewable Energy."

82 New York State Energy Research and Development Authority, "Public Attachments to Base Proposal for Champlain Hudson Power Express" (2021), 14–15, https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Clean-Energy-Standard/Tier4-Step-2-Bid-Submission-Response/Champlain-Hudson-Power-Express-Attachments.pdf.

83 New York State Energy Research and Development Authority, "Governor Hochul Announces Finalized Contracts For Clean Path NY and Champlain Hudson Power Express to Deliver Clean Renewable Energy from Upstate New York and Canada to New York City," November 30, 2021, https://www.nyserda.ny.gov/About/Newsroom/2021-Announcements/2021-11-30-Clean-Path-NY-Champlain-Hudson-Power-Express-Renewable-Energy.

engage in transmission planning processes to ensure their needs are addressed by transmission plans. An example of this in practice is California's establishment of a rebuttable presumption in favor of a transmission project's purpose and need by the CAISO.[84] This means that if a project was found to be needed in a CAISO transmission plan, the permitting proceeding for that project would assume that the project meets the need standards required for a CPCN subject to any rebuttals from intervenors and if certain criteria are met.[85] While California's rebuttable presumption may be simplified because CAISO is a single-state planning region, a multi-state transmission plan could highlight the needs of states gleaned from state engagement in planning. The results of that multi-state transmission plan could then be used directly for need determination for the permitting process, rather than having the permitting process use a separate and potentially different need determination approach. Similar presumption could be assumed for other parts of the permitting process that may be conducted by other agencies, such as evaluation of environmental impacts. This does not mean the project would automatically be issued a CPCN—it would still need to demonstrate other permitting requirements like environmental impact and cost impacts—but it could reduce some of the evidentiary burden required in permitting proceedings, particularly if developers of interregional lines need to participate in multiple state permitting proceedings.

Some stakeholders have even requested that states revise their statutes to allow permitting decisions to recognize transmission net benefits on a regional basis rather that exclusively focusing on the benefits that accrue to ratepayers within one state's borders. This solution could enable regional and interregional transmission plans to be a key resource upon which state permitting decisions are made. It could also help avoid the effort to reevaluate net benefits for each state a project passes through even after the project has been deemed beneficial on a regional basis.

Multi-State Evidentiary Record

Summary
States could *coordinate evidentiary proceedings* to synchronize permitting timelines and standardize data collected to inform decision making.
Solution Actor: State Government

Interregional transmission projects currently have independent permitting proceedings in each of the states they cross. These proceedings are often asynchronous given differences in proceeding timings and evidentiary requirements. Harmonizing the proceedings could provide benefits by aligning timelines within which permits would be issued.

One approach to this, while preserving state regulators' independence in addressing development within their state, would be to increase coordination of the evidentiary record between states. The goal of this solution is to ensure that permitting decisions made by regulators have all the relevant project information available to them, not just the impacts specific to their state. It is important to note that this would not remove any of the regulators' jurisdiction and agency, but rather increase the information and context available to them in the decision-making process. In some states' permitting proceedings, a "List of Issues" or the "Scope of Hearing" is developed and commented on at the beginning of a permitting process to establish the scope of

84 California Legislature, Assembly Bill No. 1373 – Chapter 367 (2023), (3), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240AB1373.

85 The four criteria are (a) the ISO governing board has made explicit findings regarding the need for the proposed transmission project and has determined that the proposed project is the most cost-effective transmission solution; (b) the ISO is a party to the proceeding; (c) the ISO governing board-approved need evaluation is submitted to the commission within sufficient time to be included within the scope of the proceeding; and (d) there has been no substantial change to the scope, estimated cost, or timeline of the proposed transmission project as approved by the ISO governing board; 2023 California Public Utilities Code 1001.1, https://law.justia.com/codes/california/code-puc/division-1/part-1/chapter-5/article-1/section-1001-1/.

the proceeding. It is recommended that this step be collaborated on between states so that similar evidentiary records are developed for a single project seeking permits across multiple states.

Areas of State-Level Engagement

Summary
States could *communicate transmission needs to developers and planners* to ensure proposed projects meet state needs and avoid local siting challenges. States can also *streamline permitting processes* and consider the resources and options like *transmission authorities* for improving state capabilities in transmission planning and analysis.
Example: NYISO Public Policy Transmission Planning Process

States are critical players when it comes to permitting and can engage in several areas to support interregional transmission identification and development. The first is to ensure state priorities and needs are stated early in the planning process. This ensures projects that meet those needs are the ones that move on to permitting. It also provides the planning context for a project that can be useful to state regulators when permitting a project. New York's Public Policy Transmission Planning Process is a prime example of a planning region and state regulator working together to ensure state needs are met by transmission projects.[86] NYISO solicits proposals from stakeholders for policy-driven transmission needs. Then the New York PSC compiles stakeholder proposals to finalize the statewide public policy transmission needs that act as a basis for the NYISO's project solicitation and evaluation. While this is an example of a single-state planning region, this process could be expanded across multi-state regions to ensure state-determined transmission needs are met by regional and interregional transmission plans.

The second is to spend time trying to streamline the permitting process. Permitting processes are sometimes the most uncertain and time-consuming parts of project development and require enormous amounts of resources to execute from all parties involved, especially when projects require permits from external federal and tribal permitting agencies. Taking a hard and proactive look at the largest drivers of delays that states have control over (e.g., ability of limited staff to cover all permitting applications, coordination with other agencies, and intervenor requests) can help tailor solutions to make these processes more efficient.

States could also conduct an analysis to determine how a transmission authority could help the state and what would need to be done to establish a new state agency. Establishing a transmission authority may require legislation or the use of other policy mechanisms, and funding for the agency might need to be allocated from specific budgets or other coffers. This pre-work to determine how to establish a new agency would be valuable to understand the resources and time required to set up a new transmission authority agency.

Areas of Federal-Level Engagement

Summary
The federal government could support state-led permitting enhancements with funding and training for staff. It can also get more directly involved in transmission permitting where appropriate.
Example: Coordinated Interagency Transmission Authorizations and Permits Program, National Interest Electric Transmission Corridors, and Federal Backstop Authority

86 New York Independent System Operator, *Manual 36: Public Policy Transmission Planning Process Manual* (Rensselaer, NY, 2021), https://www.nyiso.com/documents/20142/2924447/M-36_Public%20Policy%20Manual_v1_0_Final.pdf.

Many interviewees flagged that the state permitting process has limited staff support. Federal funding to support training and hiring of staff could help build out the internal expertise required for this important state role. Funding could also support standing up state transmission authorities to engage meaningfully on transmission issues and development.

In the West specifically, one of the greatest challenges sited with transmission permitting is the prevalence of federal land, which requires permitting from federal agencies in addition to state agencies. Coordinating across multiple federal agencies in addition to state agencies can be the biggest cause of delays in some cases. The DOE recently announced the Coordinated Interagency Transmission Authorizations and Permits Program, establishing coordinators to streamline federal transmission permitting processes across multiple agencies and instituting a two-year limit for reaching a final permitting decision.[87] These efforts attempt to mitigate delays that the federal government could cause in the permitting process.

Figure 10. Proposed NIETCs[88]

Should states lag on their permitting approvals, the federal government could step in to close permitting gaps. It is important to note that close engagement of states in the design of any of these approaches is imperative to ensure state input and concerns, as well as delineation of jurisdiction, are considered. One option to close permitting gaps is to expand federal backstop authority. Though existing backstop authority has seen significant roadblocks, new federal legislation could clarify and cement the ability for DOE and FERC to require states to issue permits to meet federally established priority transmission expansion needs in regions called National Interest Electric Transmission Corridors (NIETCs). There are several coordinated efforts currently underway from the federal government to exercise backstop authority for the first time in over a decade. The first is the DOE *National Transmission Needs Study*, which clearly outlines the areas of anticipated

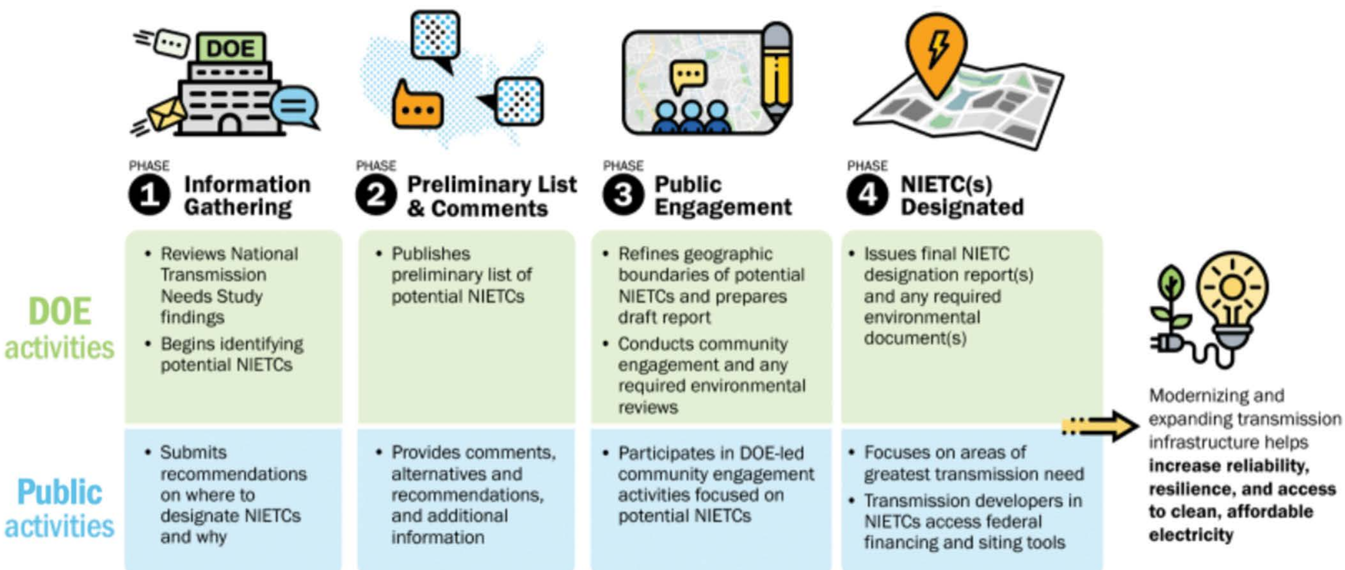
87 U.S. Department of Energy, Grid Deployment Office, "10 CFR Part 900: Coordination of Federal Authorizations for Electric Transmission Facilities," 2023, https://www.energy.gov/sites/default/files/2024-04/CITAPFinalRuleDOE.pdf.

88 U.S. Department of Energy, Grid Deployment Office, "National Interest Electric Transmission Corridor Designation Process," https://www.energy.gov/gdo/national-interest-electric-transmission-corridor-designation-process.

future regional and interregional congestion that would inform where a NIETC could be established.[89] FERC also issued Order 1977, which, in part, clarifies that its backstop authority may be used if a state fails to rule on or denies an application for siting facilities.[90] On May 8, 2024, the DOE proposed a list of 10 potential new NIETC designations that would make projects within the corridors, shown in **Figure10**, eligible for federal siting authority as well as federal financing tools made available under the IIJA and IRA.[91]

Through the new NIETC designation process illustrated in **Figure 11**, DOE aims to collaborate with impacted communities and states to overcome a past point of contention where states challenged NIETC designation because they were not adequately consulted during preparation of the underlying congestion study.[92] Designated NIETCs could provide assurance to developers and planning regions that projects within those corridors will be financially viable due to available federal incentives and will avoid delays in state siting and permitting processes. The execution of these most recent backstop authority efforts will illuminate the extent to which DOE and FERC have overcome barriers from state opposition in previous attempts at exercising their respective authorities.[93] Success of NIETC designation and new FERC regulations to implement backstop siting authority may indicate the ability to expand DOE's use of NIETC designation and FERC's use of backstop siting authority as a tool for influencing interregional transmission development.[94]

Figure 11. DOE's National Interest Electric Transmission Corridor Designation Process[95]



89 U.S. Department of Energy, *National Transmission Needs Study.*

90 Federal Energy Regulatory Commission, "18 CFR Parts 50 and 380: Applications for Permits to Site Interstate Electric Transmission Facilities."

91 U.S. Department of Energy, "Biden-Harris Administration Announces Initial List of High-Priority Areas for Accelerated Transmission Expansion," May 8, 2024, https://www.energy.gov/articles/biden-harris-administration-announces-initial-list-high-priority-areas-accelerated.

92 Other past attempts at federal backstop siting authority were also challenged when the federal government attempted to issue permits when states had previously denied them. States claimed backstop authority could only be exercised when states delayed issuing permits, not when they are denied them. The IIJA clarified that FERC can indeed use backstop authority when a state has denied permits; J. Decker, J. Jakubiak, J. Mansh, A. DeVore, and J. Silver, "The Federal Government's High-Wire Act: Setting FERC up to Employ Its Transmission Siting Backstop Authority" (Vinson & Elkins, June 6, 2023), https://www.velaw.com/insights/the-federal-governments-high-wire-act-setting-ferc-up-to-employ-its-transmission-siting-backstop-authority/.

93 Several potential barriers remain, including but not limited to, the fact that FERC may still be unable to grant eminent domain if a project passes through state land.

94 During the February 28th Joint Federal-State Task Force on Electric Transmission meeting, several state regulators expressed concerns about the NIETC and backstop authority utilization. One theme was that the DOE should work with states as well as developers to determine NIETCs to ensure developer needs are not put above those of states. Another key theme was that FERC should use information gathered and state perspectives articulated in state permitting proceedings to inform federal permitting to preserve state and local perspectives.

95 U.S. Department of Energy, Grid Deployment Office, "National Interest Electric Transmission Corridor Designation Process."

Interregional Transmission Operations and Utilization

In addition to improving planning and permitting for interregional transmission lines, it is important to pursue operational approaches that enable these ties to be utilized in the most valuable manner. Planning decisions to move forward with projects, as well as cost allocation between regions, are based on projected benefits typically identified by simulation models and other tools. For example, the Order 1920 highlights the benefits used for planning existing lines—including reliability, economic and public policy support, and required regions to evaluate a range of benefits of regional transmission facilities over long-term horizons "to meet identified transmission needs driven by changes in the resource mix and demand" (p. 157), including those listed in the Planning Methods Harmonization section.

Actualizing nearly all of these benefits depends not exclusively on the existence of new transmission facilities, but also on how the facilities are operated, and expectations of that operation by system planners and market participants. Recent historical data for operation of existing interregional transmission lines shown in **Figure 12** indicate that additional focus on operations is important to enable actual realized benefits that are equal to (or greater than) the projected estimates. A large number of the existing interregional transmission facilities are—in most hours—utilized at levels well below their full capability. The figures below show duration curves[96] of the hourly net transfer between neighboring regions in each year over the 2021–2023 period relative to the intertie capacity between the regions.[97] This figure indicates that, on the whole, transfers between these markets rarely reach their annual maximum values.

The total capacities of the interregional ties shown as dotted lines in Figure 12 are from DOE's *National Transmission Needs Study*. For some ties, these capacities are conservative estimates compared to actual capability in many hours. For example, the dotted line in the upper right pane of Figure 12 shows that the DOE Study represented total SPP-MISO intertie capacity of 12 GW. A recent SPP presentation, however, indicated that existing normal rating capacity on its interties with MISO is much higher, with 32.9 GW between SPP and MISO-North and 14.8 GW between SPP and MISO-South.[98] The data shown in the blue lines of the chart show that SPP-MISO hourly interchange from 2021–2023 did not exceed four GW, far below even the conservative 12 GW capacity estimate.

Moreover, even during particularly challenging times for certain regions, when internal generators are pushed to their maximum output levels or regions are experiencing loss of load, transactions over interregional ties have been at levels that are less than their full capability. This indicates that other limitations besides transmission intertie capacity may have caused reduced intertie transfers.

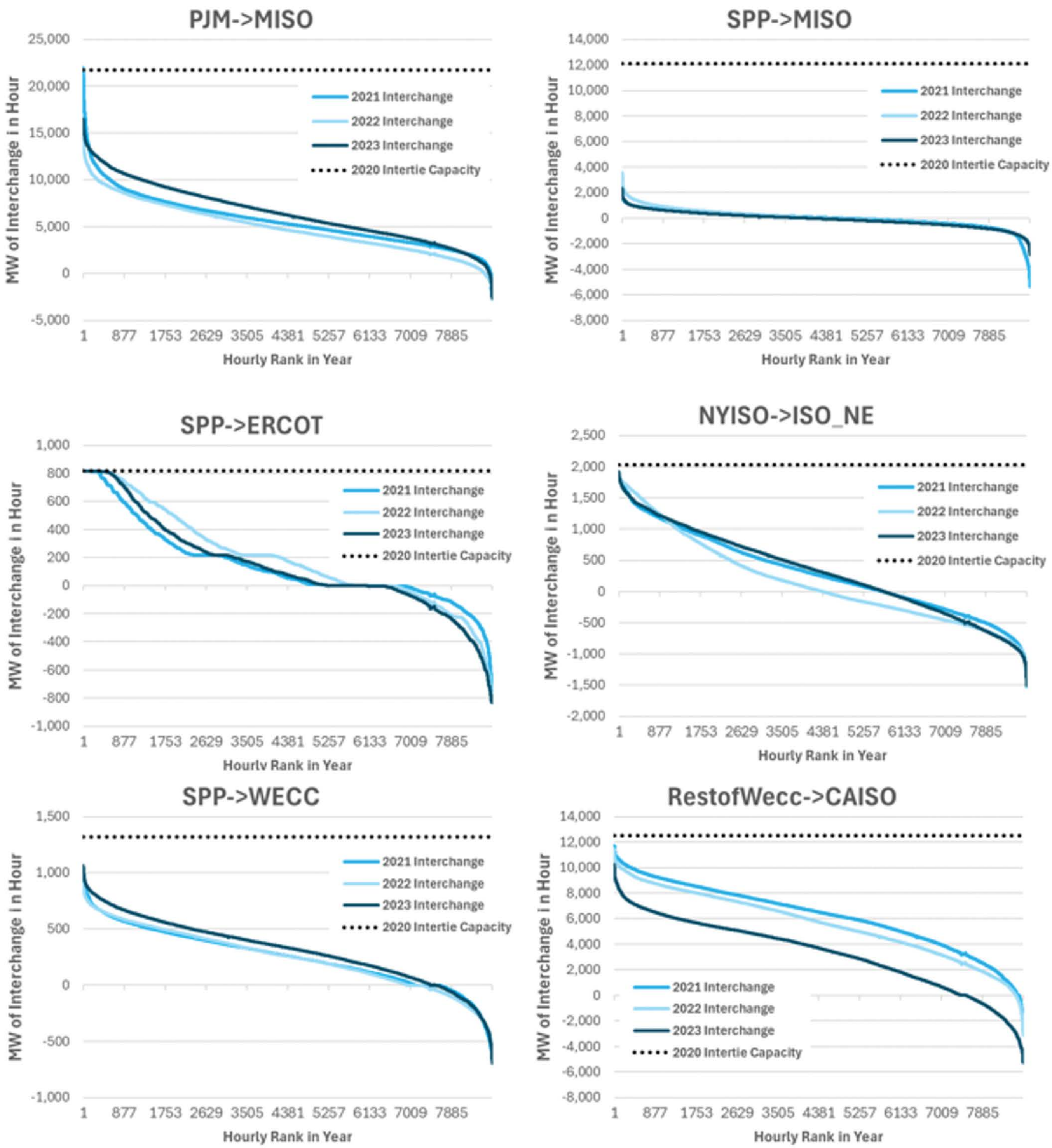
A simplified representation of economic use of transmission ties (including how the lines are often represented when projecting benefits of a new project) would typically indicate that the region with lower market prices should dispatch additional generation to make sales or exports to the region with higher prices. These exports allow the second region to back down local generation and reduce production costs, which also reduces the market prices of that region. Under this representation, the markets would increase utilization of the interties until either (i) market prices become nearly equal between the regions, or (ii) the transmission utilization reaches the operational limit of the line, which constrains the system from making further exports.

96 Duration curves visualize time series data on a chart by ordering the data by value rather than time.

97 Intertie capacity is shown as the 2020 intertie capacity between these regions as reported by the DOE *National Transmission Needs Study*; U.S. Department of Energy, *National Transmission Needs Study*, 123–124. Transmission flows from EIA Hourly Electric Grid Monitor data; U.S. Energy Information Administration, "Hourly Electric Grid Monitor," Balancing Authority/Regional Files, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

98 N. Henderson, "SPP Interregional Transfer for MGA Mid-Grid" (presentation, Southwest Power Pool, September 27, 2023), 5, https://midwesterngovernors.org/wp-content/uploads/MID-GRID-2035/2023/LittleRock-9-27-28/Presentations/NatashaHenderson.pdf.

Figure 12. Historical Utilization of Existing Interregional Transmission Interchanges



Market monitor reports from a number of jurisdictions, however, have highlighted how a significant portion of existing interregional transmission ties are unutilized even during hours when significant differences, or price spreads, exist between the market prices of the connected regions. At times, transmission schedules and flow has even occurred in the opposite direction than would seem to be economically beneficial; that is, power has been flowing from the market with higher marginal prices toward the market with lower prices.[99]

As a result of this inefficiency in actual operations, the interties may not provide as much benefit to the connected regions as they could. Efforts to improve efficient operation and economic utilization of interregional transmission, therefore, can unlock additional value from existing interties already in service and increase the likely benefits of new interregional transmission in real-world operations.

By contrast, if the challenges that currently prevent efficient operations of some existing interties remain in place, they could limit the value that a new interregional line creates compared to what planning studies may model and forecast for a new interregional transmission line. Some production simulation studies used to project economic benefits of new transmission projects do not explicitly account for the operational challenges that cause interregional lines to be underutilized. Left unaddressed, operational challenges can lead certain interregional projects to underachieve savings compared to what economic benefit studies project or can lead to inaccurate projections of the share of benefits going to each region, impacting cost allocation decisions.

Economic study results, however, can be useful in that they point to the potential additional value that new interregional ties could provide when current operational challenges are addressed.[100] Such results are helpful for underlining the importance of addressing these issues.

This chapter summarizes the barriers that can impede economic utilization of interregional transmission, identifies potential solutions to improve these issues, and highlights areas where states or federal participation can help to improve these outcomes.

Challenges to Interregional Transmission Operations and Utilization

This section covers some of the key factors that contribute to lower utilization on existing interregional transmission facilities and misalignment with economically optimal outcomes in certain time periods. Some of the factors are fundamental to the systems in place: for example, transfers over some interregional ties are limited by downstream or upstream transmission constraints within one of the connected regions. In some situations, weather and demand patterns will cause two neighboring regions to both deeply need power in the same hour, or both regions have ample low-cost supply to offer, reducing the need for efficiency gains through trading.

Operational practices for scheduling over interties, however, also contribute to or exacerbate the lower utilization of those ties, creating challenges for realizing the full benefit that the existing transmission ties could potentially provide. This section discusses the practices, which include (1) transaction charges and costs imposed on scheduling interregional transfers, (2) requirements to schedule these transactions well in advance

---

99 Monitoring Analytics, "2022 State of the Market Report for PJM," 2023, Tables 9-30 and 9-33, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec9.pdf; and additional examples cited extensively from J.P. Pfeifenberger, J. DeLosa III, J. Gozalez, N.C. Bay, and V.W. Chum, "The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission" (The Brattle Group and Willkie, October 2023), 5, https://www.brattle.com/wp-content/uploads/2023/10/The-Need-for-Intertie-Optimization-Reducing-Customer-Costs-Improving-Grid-Resilience-and-Encouraging-Interregional-Transmission-Report.pdf.

100 Study models may also provide conservatively low estimates of potential savings from new interregional projects when they do not account for other system conditions, such as generation or transmission outages or extreme weather conditions in actual practice, that boost the benefits of having the line compared to the simulation. Such omissions may partially offset the downward impact that utilization challenges discussed here have on actual realized benefits. However, if utilization and operational issues can be improved, they could lead to achievement of even higher benefits.

of the actual operating hour, and (3) uncertainty regarding whether these interregional schedules could be modified or cut when power is needed for local use.

Transaction Charges and Scheduling Costs

Many regions charge fees to market participants for scheduling energy exports to another region. When these transaction charges or export fees are applied on a per-MWh basis to the amount of energy exported they impose an economic cost or "hurdle" to making a trade between regions. Such hurdles can discourage entities from buying or selling power with a neighboring region in hours when, in the absence of these charges, it would be economically beneficial for market participants and the region as a whole to make these transactions. Separate wheeling fees are sometimes also imposed for the use of the interties themselves, compounding the economic challenges to these transactions.

Advanced-Time Transaction Requirements

Market operators of the organized markets of North America (PJM, NYISO, ISO-NE, MISO, SPP, CAISO, ERCOT, Independent Electricity System Operator (IESO, Ontario), and Alberta Electric System Operator (AESO)) each typically conduct two or more "stages" of market processes. In the day prior to actual operation, a day-ahead stage in most regions receives bids to purchase power by loads and offers by generators to sell power. The day ahead stage uses anticipated forecasts of system load and availability of resources to optimize the anticipated operation of the system over a 24-hour period, seeking to minimize system cost while serving all loads and respecting transmission and reliability constraints. This day-ahead optimization is useful for determining the need to schedule unit commitment of generators that require multiple hours of advanced notice to start up or shut down. Market operators then conduct a second market stage, termed real time, which optimizes dispatch of generators to serve an updated estimate of demand for a single time dispatch interval, or the actual operating time when the system dispatches generation and the power flows over the line, which is most typically five minutes.

The market optimization—both in the day-ahead and real-time stages—of each market typically takes bids from and dispatches specific generating resources located inside of that market's footprint but uses a different procedure for determining whether to import energy from external market footprints. These procedures are described in detail in a recent white paper produced by the Western Markets Exploratory Group (WMEG),[101] a collaboration between many utilities in the Western United States exploring pathways to Western-organized markets, with support by WMEG's consultant UtiliCast. As that report describes, "transactions between organized markets create an import schedule for one organized market and a corresponding export schedule for the other market. Import schedules are treated as offers to supply energy to the market. Conversely, export schedules are treated as bids for additional demand for the market." The operational challenge for transactions between two adjacent markets is that both markets are working simultaneously to determine the dispatch of their resources independent of the other market.

Many operator market practices require interregional schedules to be completed in advance (up to 75 minutes in some regions) of real-time operating intervals. These longer advanced times (or "latency") required for interregional transfers compared to in-market dispatch causes the participating markets to make interregional scheduling decisions based on a forecast of projected market conditions and prices, rather than actual market outcomes. Forecast errors that occur during these ahead-of-time periods can cause two problems: (a) they result in the interregional schedules being misaligned with actual system needs that manifest in real time—resulting in economically inefficient interregional transactions, and (b) they increase uncertainty and risk for market participants, which may reduce their success and willingness to participate in interregional transactions. Market participants themselves may also have less certainty about the availability of their resources at these

101 Western Markets Exploratory Group, "Seams White Paper," 2023, http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/5._Seams_Task_Force_White_Paper_-_Final.pdf.

advanced time periods and thus seek a more conservative set of offers for sales over the interties. These issues are increasingly important to address as more renewable resources are added to the system, increasing uncertainty in market needs and forecasts.

Uncertainty of Interregional Transactions

In challenging operational conditions, some market participants may be concerned that a market operator may decide to "cut schedules" or modify planned interregional transactions for operational considerations, leaving market participants to scramble for local capacity that can replace the energy they had been planning to receive from the import schedule that was cut.[102] This can cause the market participants seeking certainty to lean toward purchases from local resources instead. Dispatching resources in one region to provide capacity over an intertie for a neighboring region often results in additional transmission scheduling complexity and costs (and may have greater uncertainty), which can limit the desire of entities to sell or buy resources over the interties.

Consequences of Intertie Transmission Utilization Challenges

These utilization challenges for interregional transmission have three major consequences—two in the operational realm, and one in the planning realm.

Cost Impact to Customers (Operational): Underutilization of existing transmission interties can lead to less efficient dispatch in the broader system and increased costs to customers in either region. When intertie transactions have been economically beneficial to make but did not occur, they represent a missed opportunity for the importing region's customers to purchase energy at a lower cost than their own internal marginal cost of production, and for the exporting region's market participants to make a sale that creates net revenue beyond their costs. Such market revenues could in turn reduce potential capacity market payments or other payments generators need to maintain existing plants or enter the market.

Resilience Impact (Operational): Underutilization of existing transmission due to operational challenges can cause one region to miss an opportunity to support a neighboring region during a reliability event, including the opportunity to reduce the level of unserved energy when responding to these events. Although it is important to recognize that interregional transfers may add to the complexity of operations during reliability events, it is equally important to recognize that interties to neighboring jurisdictions may hold latent opportunities to improve each region's response to a wider range of unpredictable events.[103]

Information Impact (to Informing Planning Processes): Limited utilization of existing transmission lines can obscure the potential value of building additional intertie capability in each region's planning process. Low utilization of an existing intertie may lead planners to conclude too early that certain intertie upgrades are not worth further attention. It becomes harder to justify building new interregional projects if system operators are not able capture the value of their existing interties. When underlying challenges (such as market design or scheduling format differences) cause limits to existing transfers between regions, two things may be true:

---

102 For example, the Transmission Load Relief (TLR) standard used in the Eastern Interconnection "define the procedures for curtailing and reloading of Interchange Transactions to relieve overloads on transmission facilities modeled in the" Interchange Distribution Calculator (IDC); North American Energy Standards Board, Inc., "WEQ Transmission Loading Relief(Eastern Interconnection) Standards – WEQ-008," January 15, 2005, https://www.naesb.org/pdf2/weq_bklet_011505_tlr_numbering.pdf. Even within a single region, the possibility is present of needing to curtail a transaction or dispatch schedule to relieve transmission overloads, but when multiple regions are involved, this process is more complex, and its outcome may be more difficult to anticipate.

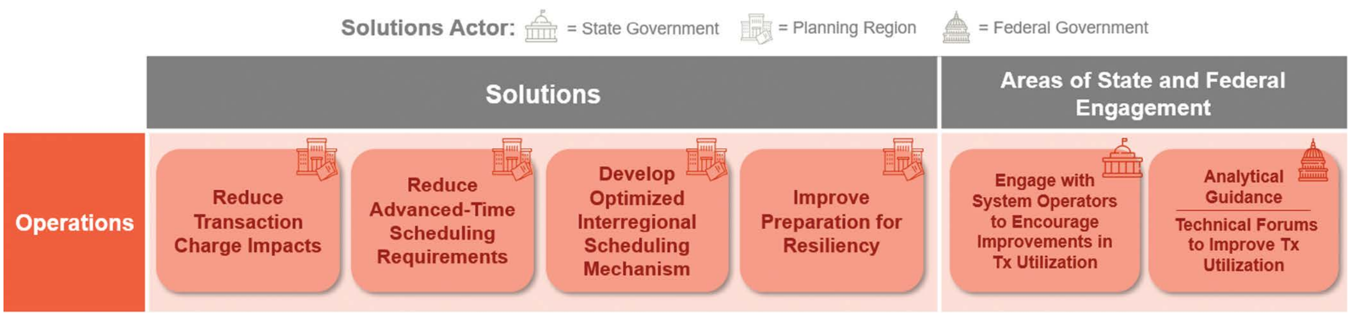
103 NERC standards that define procedures to prepare for and address energy emergencies include approaches to request emergency assistance from other Balance Authorities, and to communicate the potential for emergency needs through Emergency Energy Alerts (EEAs). Reliability Coordinators support this assistance by ensuring transmission is adequate to facilitate the emergency assistance; "Standard EOP-002-3.1 – Capacity and Energy Emergencies," https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-002-3_1.pdf. Additional coordination, however, could use interties more effectively to address emerging challenges before emergency conditions are declared.

(a) the limitations on existing lines could also limit the ability to make best use of new transmission additions, and (b) if the underlying challenges can be addressed and improved, the potential value of new interties may exceed the level that a review of historical transaction levels would otherwise indicate.

Priority Solutions and Areas of Engagement for Interregional Transmission Operations and Utilization

The drivers of interregional transmission underutilization can be technically challenging to address while having neighboring regional systems retain their independent market optimization and dispatch. These challenges notwithstanding, a number of solutions depicted in **Figure 13** may be fruitful areas for operators to pursue. This section summarizes those options. A 2023 study by the Brattle Group provides additional detail on a number of similar solutions for operational improvement.[104]

Figure 13. Solutions to Operations-Related Challenges



Reduce Interregional Transfer Costs and Fees

Summary
Transaction charges can be restructured to minimize impacts on scheduling decisions while maintaining asset owners' revenue requirements.
Solution Actor: Planning Region
Examples: NYISO and ISO-NE elimination of fees charged for Coordinated Transaction Scheduling (CTS)

Fees imposed on a per-MWh or per-transaction basis for interregional transfers have deterred the use of interregional interties. Some fees may be required to recover the investment cost of the transmission system that power flows in each region pass through when getting to the interregional tie, and to maintain consistency in allocation of these costs between load customers that consume power within one region and customers in a neighboring jurisdiction that import power. The format of these charges, however, can be set up in ways that minimize negative impacts to individual decisions regarding utilization of the interregional transmission lines. This could be through a mechanism such as an annual total allocation, or more broadly, through a solution that delinks the charged amounts from the quantity of power that is scheduled over those ties.

Reduce Ahead-of-Time Requirements and Improve Forecasts

Summary
Reducing the time between scheduling and operations will minimize chances that forecast errors render prescheduled flows inefficient.
Solution Actor: Planning Region

104 Pfeifenberger, DeLosa III, Gozalez, Bay, and Chum, "The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission."

There are technical challenges for running both market dispatch functions simultaneously when scheduling transfers between markets. Improvements toward more optimal utilization of interregional transmission can be gained through approaches that reduce the time lag between when transactions must be scheduled in advance compared to the dispatch interval. The magnitude of forecast uncertainty shrinks when this advanced time window can be shortened, which would lead to the schedules becoming more efficient. Additionally, these more efficient outcomes should increase market participants' level of confidence in economic returns from transacting over the interties.

Reducing financial risk and uncertainty for market participants will likely increase their level of interregional market participation and increase liquidity of the market overall. One approach is to utilize prices from a nearer dispatch period for scheduling rather than prices from a longer time period in advance (up to 75 minutes ahead). Using prices down to five minutes ahead of the current period would be most optimal but poses challenges due to time requirements to compute an optimal solution in each market at full resolution of a typical real-time market. This tradeoff between (a) reducing the time between setting market scheduling and operations and (b) maintaining detailed resolution of each market to best estimate prices and market needs is a challenge that warrants further exploration. Improving computing resources as well as machine learning methods for prediction of market needs and prices on a short-term basis may be worthwhile to explore further on this issue, as well as identifying the minimum set of detail and information from participants needed to anticipate what transactions will be more efficient. Similarly, effort deployed to improve forecast information (including renewable output, load forecasts, and unplanned outages) to anticipate the price signals used for interregional transactions can also help reduce uncertainty, improve the efficiency of these schedules, and encourage more market participation in these transactions.

Develop More Optimized Interregional Transmission Scheduling

Summary
New operational mechanisms can *optimize use of unutilized interregional transmission headroom.*
Solution Actor: Planning Region
Examples: Western Energy Imbalance Market, Europe's market coupling efforts

Some regions have begun exploring more thorough modifications to enable operation of interregional transmission. These approaches include potential for "optimized, but limited, joint dispatch that uses supply curves and treats seams between balancing authorities as constraints," as recommended by PJM's market monitor and suggested in other studies.[105]

An example of successful progress toward this approach is the market coupling approach utilized for interregional transactions across many European markets. This includes development of the flow-based market coupling (FBMC) mechanism and development of the Single Intraday Coupling (SIDC) platform for 15-minute trading across market borders. As described by the European Market Operator (ENTSO-E) and The Brattle Group, "SDIC creates a single 'order book' for all buy and sell bids from all the participating markets; it then continuously matches the orders from sellers and buyers until one hour before delivery time. Transmission system operators (TSOs) make any intraday cross-border capacities available to allow the bids submitted by a market participant in one market to be matched with bids in other markets. The trade is done on a first-come, first-served basis, with the highest buy and lowest sell bids matched first until the available transmission is fully utilized."[106]

105 Monitoring Analytics, "2022 State of the Market Report for PJM," 9; additional examples are discussed in Pfeifenberger, DeLosa III, Gozalez, Bay, and Chum, "The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission."

106 Monitoring Analytics, "2022 State of the Market Report for PJM," 9; additional examples are discussed in Pfeifenberger, DeLosa III, Gozalez, Bay, and Chum, "The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission.

The Western Energy Imbalance Market (EIM)[107] operated by CAISO has improved the efficiency of real-time dispatch and operations between many Balancing Authority Areas (BAAs) across the Western United States and Canada. The efficiency gains enabled by this market are facilitated by the fact that EIM-participating BAAs outside of CAISO are not participants in a separate organized regional market. This factor enables the EIM to expand the use of the CAISO real-time market dispatch across a broader footprint. While the EIM only operates in real time after prescheduled transfers are determined through bilateral transactions, participation has expanded rapidly in the West, and it may provide an approach that can be deployed more quickly in jurisdictions that are not currently seeking to be part of an organized market but geographically adjacent to existing markets (e.g., Southeast United States entity participation with PJM, MISO, or SPP). This approach would be more challenging to apply between two organized markets with their own separate dispatch processes. At the same time, the benefits created by the EIM are indicative of the potential benefits for developing new, creative solutions for improving more optimal use of interregional transmission. There are certain key elements for realizing the potential benefits of this type of approach, including (1) robust participation of generators in the footprint of an EIM or EIM-like market, as well as (2) making significant transmission available for real-time transactions, which will modify hourly schedules. If utilizing this approach, it is important to seek ways to address challenges that may limit generator or transmission participation.

Improving Utilization of Interties for Resiliency

Summary
Neighboring market operators can work together to *define possible emergency conditions* and *establish protocols* for rapid communication and operations during periods of high resiliency need.
Solution Actor: Planning Region

As resiliency is a significant benefit identified for interregional transmission projects, it is important to prepare for how resiliency can be realized in actual operations. While certain types of resiliency events are inherently difficult to predict, more preparation for coordinated intertie use between neighboring markets on a range of resilience issues could be useful. For example, market operators can delineate conditions under which they would deviate from normal market operations to deal with an emergency versus when to remain in a normal approach. Markets can also define protocols for more rapid communication between connected regions during emergency events. Specific details of how this coordination should be implemented may be best identified by market operators, but prioritizing the need to use these approaches is important. Sharing lessons learned across regions (even beyond those with direct connections) can also help to promote wider learning.

Areas of State-Level Engagement

Summary
States could *encourage utilities and system operators* to engage in improved interregional transmission utilization methods.

State entities could strive to highlight and encourage more optimal interregional transmission utilization as an important priority for planners and operators. To the extent that new projects are expected to bring certain benefits, addressing operational issues is essential to ensure that projected benefits can be realized in actual practice. State entities can communicate to market operators their support for operators to develop and propose alternative solutions to promote more economic intertie optimization.

107 ENTSO-E, "Single Intraday Coupling," https://www.entsoe.eu/network_codes/cacm/implementation/sidc/; and discussion in Pfeifenberger, DeLosa III, Gozalez, Bay, and Chum, "The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission."

Areas of Federal-Level Engagement

Summary
Federal government could provide *guidance* and hold *technical forums* on improving interregional transmission utilization.

Similarly, FERC and other federal entities can direct and encourage operators to identify solutions that promote more optimal use of interties. Additionally, for resiliency, where improved operational decisions at the right time could provide significantly more value than regular economic optimization in most hours, federal agencies and national labs can help to provide analysis and guidance on resiliency situations that operators could prioritize for interregional operations coordination plans. FERC and DOE can also provide technical forums and develop best practices and guidelines for planning regions to participate in and use as they explore enhancing intertie utilization.

Conclusion

Planning, permitting, and operating interregional transmission to maximize system benefits is challenging. But in the face of massive transformation of the power sector over the coming decades, it is crucial we take steps to enable the identification of beneficial interregional transmission through planning, allow for those projects to be evaluated and accurately valued during the permitting process, and operate those projects to maximize system benefits when put into service. The consequences of not taking these steps could mean the development and operation of a more expensive grid (on both the generation and transmission side), increased frequency of reliability events, and the introduction of disruptive solutions, such as federal preemption, that limit states' ability to advocate for transmission that fits their specific needs and priorities.

Taking the steps suggested in this report may not be the path of least resistance as it requires states and planning entities to engage and collaborate in ways that are potentially new and different from current practices. The elements of engagement and collaboration discussed in the report are derived from successful examples seen recently in different jurisdictions, which suggest they could result in meaningful state- and region-led transmission planning if employed on a wider basis going forward.

The top priority areas for focus include:

- A collaborative approach to interregional transmission planning across states and planning regions to enable joint identification of transmission needs and coordinated, or combined, analysis of solutions.
- State engagement in regional and interregional transmission planning processes to help support permitting processes for any projects selected to move on to permitting.
- Exploration of the development of new state agencies dedicated to transmission development, such as state transmission authorities, to have state-level support and expertise.
- Improvements to intertie utilization including reducing transaction charges on interregional transmission schedules, shortening the advanced time when interregional transactions must be scheduled before the dispatch interval, developing joint dispatch approaches with shared supply curves between regions, and jointly preparing for how regions can use interregional transmission to respond to resiliency challenges.
- Opportunities for federal support to enable the state- and planning-led approaches discussed above through direct funding, identification of gaps in current planning, development of best practices and guidelines, and convening of stakeholders from across the industry to engage in information sharing.

Appendix A: Literature Review

Title	Organization	Link
A Roadmap to Improved Interregional Transmission Planning	Brattle Group	https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf
Building a New Grid without New Legislation: A Path to Revitalizing Federal Transmission Authorities	Columbia SIPA Center of Global Energy Policy	https://policyintegrity.org/files/publications/New_Grid_Without_Legislation_report.pdf
Converting Existing Transmission Corridors to HVDC Is an Overlooked Option for Increasing Transmission Capacity	Department of Engineering and Public Policy at Carnegie Mellon University – PNAS	https://www.pnas.org/doi/full/10.1073/pnas.1905656116
Coordination of Federal Authorizations for Electric Transmission Facilities	Grid Deployment Office, U.S. Department of Energy	https://www.energy.gov/sites/default/files/2024-04/CITAPFinalRuleDOE.pdf
Do Grid Operators Dream of Electric Seams? Coordinating Interregional Transmission Stakeholders to Improve Energy Deliverability	George Washington Journal of Energy and Environmental Law	https://heinonline.org/HOL/LandingPage?handle=hein.journals/gwjeel13&div=10&id=&page=
Electric Transmission Seams: A Primer White Paper	National Regulatory Research Institute, prepared for EISPC and NARUC	https://pubs.naruc.org/pub/FA86CD9B-D618-6291-D377-F1EFE9650C73
Expanding Transmission Capacity: Examples of Regulatory Paths for Five Alternative Strategies	Department of Engineering and Public Policy at Carnegie Mellon University and Vermont Law School , The Electricity Journal	https://doi.org/10.1016/j.tej.2020.106770
FERC NOPR: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	Federal Energy Regulatory Commission	https://www.ferc.gov/media/rm21-17-000
FERC Order 1920: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation	Federal Energy Regulatory Commission	https://www.ferc.gov/media/e1-rm21-17-000
FERC Order 1977: Applications for Permits to Site Interstate Electric Transmission Facilities	Federal Energy Regulatory Commission	https://ferc.gov/media/e-2-rm22-7-000

Title	Organization	Link
Interconnections Seam Study	National Renewable Energy Laboratory	https://www.nrel.gov/docs/fy21osti/78161.pdf
Interregional Transmission Benefit Accrual Study	Energy & Environmental Economics, Inc. (E3)	https://www.electricity.ca/files/reports/english/20221109-E3-Interregional-Transmission-Benefit-Accrual-Executive-Summary-9.pdf
National Transmission Needs Study	Grid Deployment Office, U.S. Department of Energy	https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf
Re-focussing Research Efforts on the Public Acceptance of Energy Infrastructure: A Critical Review	The Energy Institute at Johannes Kepler University, Energy (Journal)	https://www.researchgate.net/publication/260007646_Re-focusing_research_efforts_on_the_public_acceptance_of_energy_infrastructure_A_critical_review
Regional and Interregional Transmission Have Significant Economic Value	Lawrence Berkeley National Laboratory	https://emp.lbl.gov/news/regional-and-interregional
Regional and Inter-regional Transmission Planning and Cost Allocation	Midwest Independent System Operator, IEEE	https://ieeexplore.ieee.org/abstract/document/6345711
Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000 (2017)	Lawrence Berkeley National Laboratory	https://emp.lbl.gov/publications/regional-transmission-planning-review
The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission (2023)	The Brattle Group	https://www.brattle.com/wp-content/uploads/2023/10/The-Need-for-Intertie-Optimization-Reducing-Customer-Costs-Improving-Grid-Resilience-and-Encouraging-Interregional-Transmission-Report.pdf
Research Review: The Role of Transmission in the Context of Deep Decarbonization	Energy & Environmental Economics, Inc (E3), prepared for Electricity Canada	Internal
The Value of Inter-regional Coordination and Transmission in Decarbonizing the U.S. Electricity System	Energy Initiative, MIT, Joule Journal	https://doi.org/10.1016/j.joule.2020.11.013

Title	Organization	Link
Transmission Stalled: Siting Challenges for Interregional Transmission	Niskanen Center	https://www.niskanencenter.org/transmission-stalled-siting-challenges-for-interregional-transmission/
Triple Jeopardy: How ISOs, RTOs and Incumbent Utilities Are Killing Interregional Transmission	Edward N Krapels – Anbaric Development Partners, The Electricity Journal	https://doi.org/10.1016/j.tej.2018.03.001
Why the Vision of Interregional Electric Transmission Development in FERC Order 1000 Is Not Happening	Schulte Associates LLC and Power from the Prairie LLC, The Electricity Journal	https://www.sciencedirect.com/science/article/pii/S1040619020300658

Appendix B: Interviewees

Interviewee	Position	Organization	Category
Stephen Bennett	Manager, Regulatory/ Legislative Affairs	PJM Interconnection (PJM)	System Operator
Christina Drake	Director, Economic & Policy Planning	Midcontinent Independent System Operator (MISO)	System Operator
Andrew J. French	Chairperson	Kansas Corporation Commission	State Regulator
Asim Haque	Senior VP, State & Member Services	PJM Interconnection (PJM)	System Operator
Natasha Henderson	Director, System Planning	Southwest Power Pool (SPP)	System Operator
Doug P. Scott	Chairman	Illinois Commerce Commission	State Regulator
Michael Skelly	Chief Executive Officer	Grid United	Transmission Developer
Robert Taylor	Senior Director, Transmission New Markets	Invenergy	Transmission Developer

NARUC
National Association of Regulatory Utility Commissioners

1101 Vermont Ave, NW • Suite 200 • Washington, DC 20005
www.naruc.org • (202) 898-2200