Barriers and Opportunities To Realize the System Value of Interregional Transmission

Christina E. Simeone and Amy Rose

National Renewable Energy Laboratory

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Preface

This report—*Barriers and Opportunities To Realize the System Value of Interregional Transmission*—examines the barriers and identifies potential opportunities within existing market and operating rules to achieve the benefits of coordinated transmission planning and operations for electric customers. This report is part of the U.S. Department of Energy's (DOE's) National Transmission Planning Study (NTP Study), conducted by the National Renewable Energy Laboratory and Pacific Northwest National Laboratory. The aim of the NTP Study is to identify transmission that will provide broadscale benefits to electric customers, inform regional and interregional transmission planning processes, and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability. More information on the NTP Study is available at https://www.energy.gov/gdo/national-transmission-planning-study.

In addition, the NTP Study includes two other complementary reports focused on implementation and action. The forthcoming report *Regulatory Pathways to New Interregional Transmission: A Landscape Assessment* is a companion to this report under the NTP Study umbrella (Homer et al. forthcoming). That report explains the regulatory challenges to building new interregional transmission that have historically prevented realizing many of the benefits quantified in the NTP Study technical scenario. The report *Interregional Renewable Energy Zones* uses the national modeling conducted for the NTP Study to identify specific high-value interregional zones for renewable energy development and the coordination steps required to realize the benefits of these zones. Together, this report and other volumes in the NTP Study series provide a knowledge base that states, industry, transmission planners, policymakers, and others can use to achieve some of the benefits revealed in the NTP Study's national scenarios.

Acknowledgments

Members of the National Transmission Planning Study (NTP Study) technical review committee—which included experts representing various system operators, utilities, industry organizations, Tribal nations, state and federal agencies, nongovernmental organizations, and others—helped guide the NTP Study to identify and address relevant questions. The authors would like to thank the individuals from the committee who provided their input on any of the topics discussed in this report. The opinions contained in this report are those of the authors and do not reflect the specific views or interpretations of specific members of the committee or their institutions.

The authors are also greatly indebted to several individuals for their thoughtful feedback and guidance, including Yonghong Chen, Jess Kuna, David Palchak, Trieu Mai, David Hurlbut, Jaquelin Cochran, Mark Ruth, and Dan Bilello from the National Renewable Energy Laboratory (NREL) and Yamit Lavi, Adria Brooks, Jay Caspary, Rian Sackett, Melissa Birchard, and Patrick Harwood from DOE's Grid Deployment Office. Emily Horvath and Madeline Geocaris (NREL) provided editing support. Any errors and omissions are solely the responsibility of the authors. This work was funded by DOE's Grid Deployment Office.

List of Acronyms

AC	alternating current
ATC	available transmission capacity
BAA	balancing authority area
BRA	base residual auction
CACM	Capacity Allocation and Congestion Management
CAISO	California Independent System Operator
CIL	capacity import limit
CTS	coordinated transaction scheduling
DOE	U.S. Department of Energy
DRI	demand-at-risk indicator
ENTSO-E	European Network of Transmission System Operators for Electricity
FERC	Federal Energy Regulatory Commission
FFE	firm flow entitlement
GW	gigawatt
GWh	gigawatt-hour
HVDC	high-voltage direct current
IESO	independent electricity system operator
IMO	independent electricity market operator
ISO	independent system operator
ISO-NE	Independent System Operator of New England
JOA	joint operating agreement
M2M	market-to-market
MISO	Midcontinent Independent System Operator
MMU	Market Monitoring Unit
MRO	Midwest Reliability Organization
MW	megawatt
MWh	megawatt-hour
NEMO	nominated electricity market operator
NERC	North American Electric Reliability Corporation
NAESB	North American Energy Standards Board
NTP Study	National Transmission Planning Study
NYISO	New York Independent System Operator
Ofgem	Office of Gas and Electricity Markets
PAR	phase angle regulator
PCI	projects of common interest
PFP	pay-for-performance
PFV	parallel flow visualization
PJM	PJM Interconnection
RC	reliability coordinator
RTO	regional transmission organization
SERC	Southeastern Reliability Corporation
SPP	Southwest Power Pool
SPTO	subscriber participating transmission owner
TCR	transmission congestion rights
TLR	transmission loading relief

TSO	transmission system operator
TYNDP	10-year network development plan
UFMP	Unscheduled Flow Mitigation Plan
WECC	Western Electricity Coordination Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Services
WRAP	Western Resource Adequacy Program

Executive Summary

This report identifies barriers within rules and operational practices that may limit the value existing interregional transmission can provide to electric consumers and identifies a suite of options that could enable greater use of and value from interregional transmission. To allow for the variety of power sector structures that exists across the United States, the report divides the evaluation of barriers and opportunities into three sections: common issues found in all regions, barriers between nonmarket or hybrid areas, and barriers between market areas. The report also identifies ambitious, transformative national actions that could unlock transmission value across both market (e.g., between regional transmission operators) and nonmarket (e.g., areas that primarily rely upon bilateral transactions) areas. This report provides an overview, rather than a complete or exhaustive list, of barriers and solution options and generally examines historic issues rather than reasonably anticipated concerns.

In the analysis of barriers and potential opportunities for improvement, we recognize these are technically complex issues with a diverse set of power system stakeholders and factors that must be considered. We further recognize this report does not fully explore the complicated issues grid operators face when seeking to address these barriers, such as changing financial outcomes and the potential creation of winners and losers in markets. The aim of this report is not to make recommendations but to identify options to improve the use of interregional transmission that could be considered alongside other local, state, regional, and stakeholder objectives. While this report is focused on issues that prevent *existing* transmission facilities from delivering maximum potential value, the findings have important implications for future transmission investments.

Barriers To Capturing the Value of Interregional Transmission Capability

In both market and nonmarket regions, we find the absence of a framework for resource adequacy sharing may discourage grid operators from relying on external resources for reliability. A second common issue is transmission owners and operators have limited operational awareness to anticipate when large power transfers are needed. This is especially relevant in response to extreme weather events when interregional transmission could enable large power transfers to maintain reliability. Third, planning for within-region transmission networks may not account for large power flows across the network to accommodate increased imports and exports with neighboring regions.

Among nonmarket regions or between market-to-nonmarket hybrid regions, we find inconsistent or uncoordinated approaches to scheduling and real-time operations may result in the inefficient use of interregional transmission. Uncoordinated bilateral trading has inherent limitations that may not be able to identify lowest-cost resources to meet system needs and may prevent the ability to adjust to real-time operating conditions. In hybrid regions, regional practices to prioritize market transactions—even during emergency conditions—can reduce system reliability. Uncoordinated approaches to congestion management can pose reliability risks across critical transmission corridors and limit the ability to use scarce interregional transmission capacity for economically efficient power trades. Finally, inconsistent approaches to estimate and communicate available transfer capacity across interregional lines can result in underutilized or oversubscribed transmission lines.

Most of the market-to-market issues relate to inefficiencies in joint operating agreement programs between market regions. First, inaccurate price forecasts and high transaction fees limit the efficient use of transmission capacity through coordinated transaction scheduling. In daily operations, issues with interface pricing between regions can lead to operational inefficiencies such as loop flows, economic inefficiencies such as redundant charges, and opportunities for market manipulation through sham scheduling where scheduled flows do not match actual flows. We also find outdated flow limits and inaccurate modeling of interregional lines leads to excessive costs for congestion management that are borne by ratepayers. Finally, we find most regional markets lack the ability to optimize the use of available merchant high-voltage direct current (HVDC) transmission capacity, which leads to inefficient use of these grid assets.

Opportunities

For each of the identified barriers, we describe potential options that policymakers, regulators, and system operators could pursue to improve the efficient use of interregional transmission. These options, summarized in Figure ES-1, include actions tailored to the specific needs and power sector structures in different planning regions—including options for market, nonmarket, or hybrid areas—as well as options common to all areas. These reforms could both significantly enhance the value of interregional transmission and deliver additional within-region benefits not related to interregional transmission.

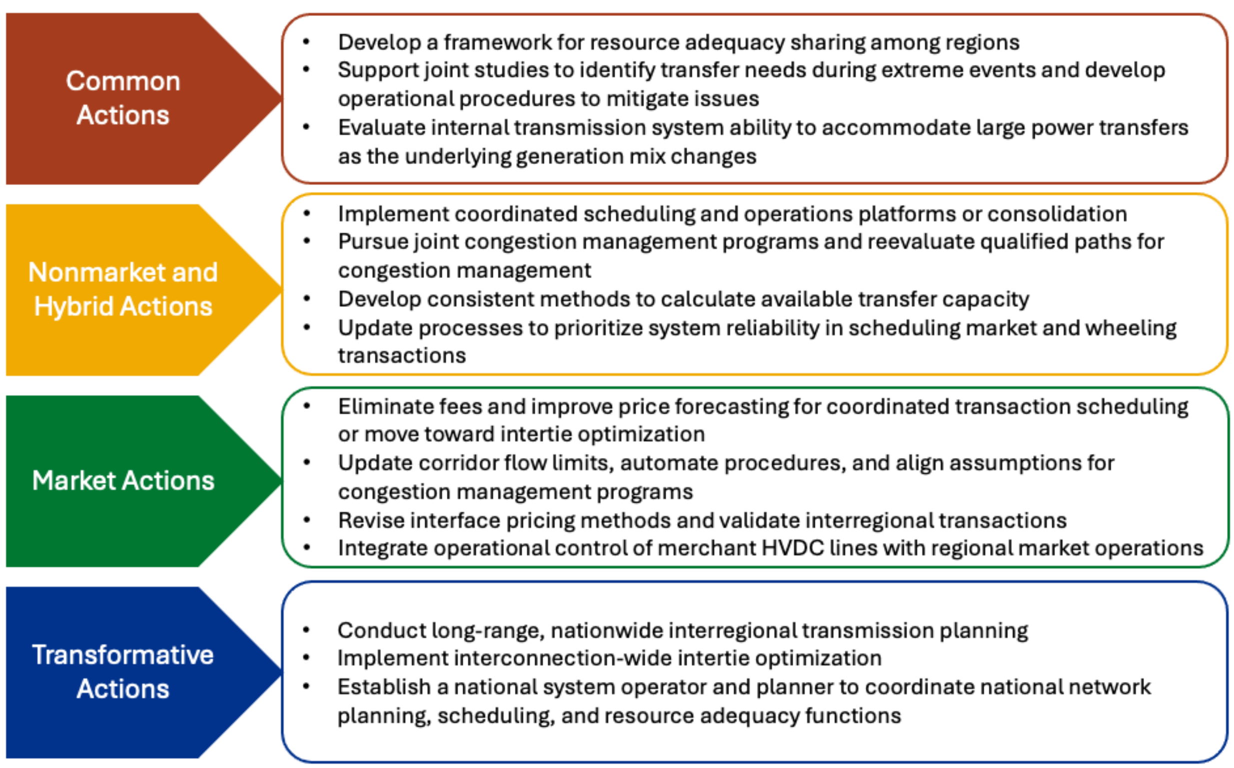

Figure ES-1. Summary of incremental and transformative opportunities to realize the system value of interregional transmission

This report also identifies transformative opportunities that could be implemented more broadly across the multiple regions to maximize the system benefits of interregional transmission. These options include national transmission and resource planning, multiregion or interconnection-wide optimization, and a combination of these responsibilities. Although the total benefits of these opportunities are not directly quantified, we note the portion of total benefits attributed to interregional transmission generally increases as the geographic scope and level of coordination increases.

As the United States seeks to transform its electricity supply with increased shares of clean energy, the electricity grid will need to transform in parallel to accommodate new sources of supply with new output profiles developed across the country. The National Transmission Planning Study (NTP Study) identifies a suite of transmission options that will provide broadscale benefits to electric customers, inform regional and interregional transmission planning processes, and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability. The NTP Study demonstrates coordinated planning and operation of the national transmission grid—including increased development of interregional transmission—can reduce the cost of meeting energy, reliability, and reserve requirements by hundreds of billions of dollars. Though this report focuses on issues that prevent *existing* transmission facilities from delivering maximum potential value, the findings have important implications for future transmission investments. The barriers and opportunities identified in this report can guide the suite of reforms needed to realize these systemwide benefits.

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1 Introduction

The National Transmission Planning Study (NTP Study) identifies a suite of transmission options that could provide broadscale benefits to electric customers, inform regional and interregional transmission planning processes, and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability. Among these options, expanded investments in interregional transmission capability show the greatest potential to meet national imperatives for reliability, resilience, and reduction in greenhouse gas emissions at the lowest cost and deliver a wide range of system benefits. The NTP Study finds accelerated transmission development could result in hundreds of billions of dollars in systemwide savings under a range of decarbonization scenarios compared to meeting these targets with more limited development of transmission between regions.[1] The savings include avoided capital and operating costs to meet system requirements for energy and reliability. In practice, a host of barriers may exist that prevent the realization of these and other interregional transmission benefits.

This report identifies barriers within existing rules and operational practices that may limit the system value interregional transmission can provide and identifies a suite of options that could enable greater use of and value from interregional transmission. To allow for the variety of power sector structures that exists across the United States, the report divides the evaluation of barriers and opportunities into three sections: common issues found in all regions, barriers between nonmarket or hybrid areas, and barriers between market areas. The report also identifies ambitious, transformative national actions that could leverage transmission capability to further lower system costs across both market and nonmarket areas. Though this report focuses on issues that prevent *existing* transmission facilities from delivering maximum potential value, the findings have important implications for future transmission investments. Interim results from the NTP Study estimate significant growth in new transmission capacity, expanding the current grid by about 2 to 4 times by 2050, to achieve a reliable, resilience, and decarbonized power system at the lowest cost by enabling the interconnection of large amounts of low-cost wind and solar. Given the significant magnitude of electricity transmission investments needed, ensuring these investments are operating efficiently to maximize the value they can provide to the system is increasingly important.

This report begins by identifying the potential benefits of interregional transmission and indicators that interregional transmission benefits may not be fully realized in practice (Section 2). Section 3 identifies barriers to achieving full interregional transmission value and proposes options to realize transmission value. Section 3 is divided into three subsections: barriers common to all areas, barriers between nonmarket or hybrid (trades between market and nonmarket) areas, and barriers between markets. The opportunities in Section 3 are tailored to each barrier, whereas Section 4 identifies transformative options that could allow for interregional transmission value maximization.

[1] For more information on the NTP Study modeling results, see *National Transmission Planning Study* (Palchak et al. forthcoming).

2 The Promise and Reality of Transmission Benefits

There is broad recognition that coordinated planning and management of regional and interregional transmission infrastructure can provide a range of system benefits. However, there are signs these benefits are not fully captured for existing transmission facilities.

2.1 Benefits of Transmission

Electricity transmission can provide a wide range of system benefits by increasing the geographic footprint of the system to enable greater use of the most efficient resources. Historically, production cost savings[2] has been the primary metric for valuing transmission investments, but transmission can also provide environmental benefits, access to low-cost renewable energy, generation capital cost benefits, risk mitigation benefits, and improvements in reliability and resilience (Chang, Pfeifenberger, and Hagerty 2013) (Figure 1).

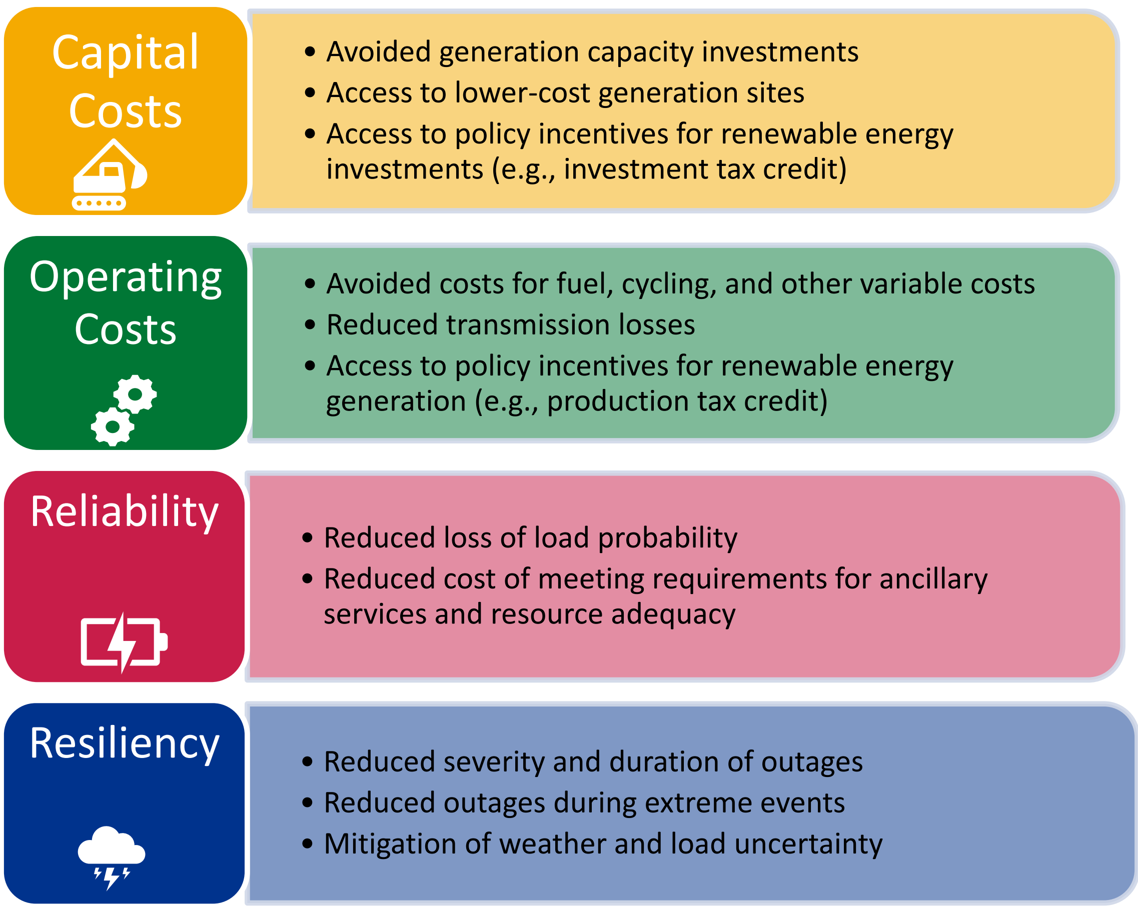

Figure 1. Potential benefits of electricity transmission

[2] Production cost savings or adjusted (for imports and exports) production cost savings typically consider the avoided electricity production costs associated with accessing lower-cost generation resources through economic dispatch and trades with neighboring systems.

Though the transmission benefits in Figure 1 are listed individually, many are not mutually exclusive. For example, interregional transmission investments that reduce the cost of meeting ancillary service requirements may also reduce capital investments needed to meet these requirements.

2.2 Symptoms of Inefficiency

For years, market monitors and electricity stakeholders have pointed to signals that transmission capacity and scarce interregional capacity, in particular, are not being used efficiently. Efficient use of interregional capacity could maximize the ability of these assets to flow low-cost power from one region to load in a neighboring region, displacing higher-cost power. The following issues can be potential indicators of inefficient use of interregional transmission:

- **Uneconomic Flows:** Power flows in uneconomic directions—meaning from higher-price areas to lower-price areas—provides clear evidence that something is not working properly. Short periods of uneconomic flows may not be an indicator of inefficiency compared to longer or reoccurring periods.

- **High Price Differentials:** The appearance of high price differentials, when there is a significant spread in power prices between regions, indicates an opportunity to lower prices through trade. Persistent high price differentials may indicate beneficial trading is not taking place, representing a missed opportunity to reduce customer costs in the high-priced region.

- **Underutilized Capacity:** Underutilized transmission assets may signal these assets are not being used efficiently to bring lower-priced power to higher-priced regions. Underutilized capability may not be an indicator of inefficiency, for example, if there is no available lower-priced power to move to higher-priced areas.

- **Lack of Transparency on Inefficiencies:** Other symptoms, such as a lack of transparency in interchange transactions, have more subtle and less direct impacts on the efficient use of electricity transmission. Lack of transparency itself may not be an issue; rather, lack of transparency is an obstacle to identifying inefficiencies—and opaqueness is more likely to occur in areas with less market oversight (e.g., lack of market monitoring).

These symptoms of inefficient interregional transmission use are discussed in detail in the following sections.

2.2.1 Uneconomic Flows and High Price Differentials

In a well-coordinated system with efficient use of transmission capacity, power is expected to flow from areas of lower price to areas of higher price. However, a large volume of interchange flows occurs in the uneconomic direction, meaning power is moving from higher-priced areas to lower-priced areas. In addition, high price differentials existed during many hours where uneconomic flows prevailed. This potentially represents an economic inefficiency in the use of interregional transmission. However, some of these high-to-low prices flows could be occurring because of bilateral agreements or wheeling transactions that do not depend on market price differentials.

Figure 2 shows the percentage of hours with uneconomic power flows across four major interregional seams in 2022 (Monitoring Analytics, LLC 2023; ISO-NE Internal Market Monitor 2023; Potomac Economics 2023c).

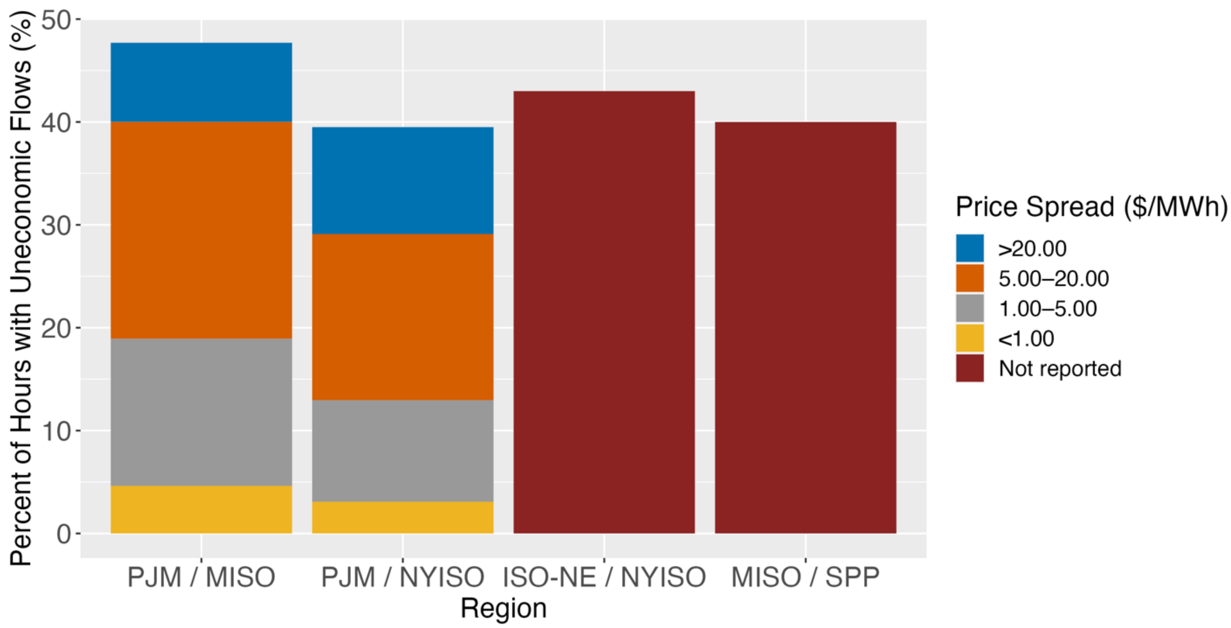

Figure 2. Hours with uneconomic power flow across major interregional seams in 2022

Price spread means the difference in average hourly locational marginal prices between regional interfaces

PJM Interconnection (PJM) and Midcontinent Independent System Operator (MISO) experienced the highest percentage (48%) of uneconomic flows in 2022 according to the PJM market monitor (Monitoring Analytics, LLC 2023). Though the MISO market monitor estimates this value is closer to 40%, it still represents a large share of the year with uneconomic power flows (Potomac Economics 2023c). In almost 30% of hours, the average locational marginal price difference between the regions was over $5/megawatt-hour (MWh). Across the Independent System Operator of New England (ISO-NE) and New York Independent System Operator (NYISO) interfaces, power flowed in the economic direction for only 57% of hours. Between MISO and Southwest Power Pool (SPP), power flowed in the economic direction for about 60% of hours. PJM and NYISO also experienced high shares of uneconomic transactions, even during periods when the price differences between the markets exceeded $5/MWh.

Section 3 explores potential reasons for high shares of uneconomic flows across these different regional pairs and possible options to increase the efficient use of interregional transmission links.

2.2.2 Underutilized Interchange Capacity

As discussed previously, when there is a price differential between transmission systems, interregional transmission can facilitate the transfer of lower-priced available supply areas with higher-priced supplies. In practice, evidence suggests some interregional transmission capacity is being underutilized despite large price differentials. In Figure 3, ISO-NE's internal market monitor identifies the unused but available interface capacity between ISO-NE and NYISO in

2022 associated with the coordinated transaction scheduling (CTS) mechanism (ISO-NE Internal Market Monitor 2023, 162). These data indicate even when price differences were high, there was unused interface capacity available to move lower-priced power to higher-priced areas and these opportunities occurred often throughout the year. For example, in 24% of hours in the year when price differentials between ISO-NE and NYISO were between \$10 and \$25, there was on average 250 megawatts (MW) of unused available interface capacity (ISO-NE Internal Market Monitor 2023).

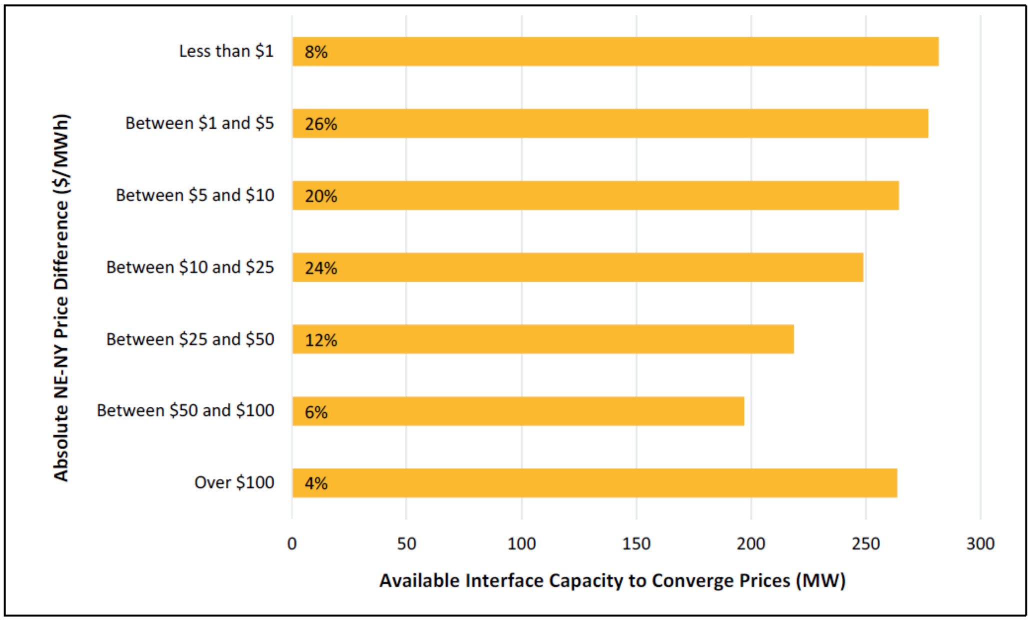

Figure 3. ISO-NE to NYISO unused coordinated transaction scheduling capacity, 2022

The percentages on each bar show the percent of time each price bin occurred during the year. The x-axis is average available but unused CTS interface capacity (ISO-NE Internal Market Monitor 2023, 162).

2.2.3 Lack of Transparency on Inefficiencies With Bilateral Trading

Bilateral contracting was the predominant form of wholesale transaction until the mid-1990s with the introduction of restructuring (Energy Policy Group, LLC 2016). Bilateral trading relies on negotiated wholesale contracts or agreements between willing buyers and sellers. These transactions are common in both market and nonmarket regions. Proponents of bilateral trading argue that these agreements have been more effective at catalyzing new capacity investments, reducing risk associated with stranded costs, and, in nonmarket regions, meeting system needs without the cost overlay of operating a centralized market (Energy Policy Group, LLC 2016).

Nonmarket settings have less publicly reported data available on outcomes, operations, and efficiency than regional transmission organizations (RTOs) and independent system operator (ISO) markets that have market monitoring and reporting requirements. This absence of available data can make it more difficult to detect potential inefficiencies and other market issues. For example, most of the data and information supporting this report was found in RTO/ISO market monitoring reports whereas significantly less information was available for areas outside of RTOs/ISOs.

The Federal Energy Regulatory Commission (FERC) promulgated Order No. 888 to remedy inefficiencies and undue discrimination observed in bilateral markets at the time (Federal Energy Regulatory Commission 1996). Order No. 888 required all public utilities to have on file at FERC open access transmission tariffs containing minimum terms and conditions for nondiscriminatory access to transmission services and ancillary services, which was meant to address public utility discrimination against competitors. The rule also provides guidance on the formation of ISOs, which were meant to promote competition and efficient operations—leading to just and reasonable rates. Although open access is a requirement in the United States, certain issues have existed in purely bilateral markets that provide insights into the efficiency of these nonmarket balancing authority area (BAA)-to-BAA transactions.[3,4]

- **Rate Pancaking:** Rate pancaking occurs when wheeling energy across multiple transmission systems and incurring multiple fees to move across different service territories. This process increases transaction costs and can be a barrier to the use of least-cost generation (Mountain West Transmission Group 2017). Brattle performed a study for the Mountain West Group that estimated $14 million in adjusted production cost savings per year associated with moving from the status quo bilateral market (with rate pancaking) to a bilateral market with a joint transmission tariff (Chang, Pfeifenberger, and Tsoukalis 2016). The same study found moving from a bilateral market to an RTO construct would result in $88 million in annual savings.

- **Trade Friction:** Bilateral trading has inherent trade friction that causes inefficiencies. This friction can include the need to pay brokers or administrative charges, manually arranging trades by phone or other means, and coordinating transmission scheduling with the other utility (Tsoukalis et al. 2023). The South Carolina General Assembly commissioned a report from Brattle to assess the benefits of reforming the state's existing electricity sector. One option considered was moving from the status quo of bilateral trading with neighbors to a joint dispatch agreement to facilitate trade among all Carolina utilities. The joint dispatch agreement construct would have one utility coordinating and automating generator dispatch between utilities in real time (5- and 15-minute increments), using any spare supply and transfer capacity between areas to meet load. The study estimates annual net benefits of moving to a joint dispatch agreement to be $6 million to $11 million per year (Tsoukalis et al. 2023).

- **Limited Real-Time Options:** Because of trade friction and issues associated with transmission scheduling, a bilateral trading regime may be inherently limited, especially for addressing real-time operational needs (Federal Energy Regulatory Commission Staff 2013). These areas often have limited temporal granularity of scheduling and dispatch (e.g., hourly only, 30-minute), which forestalls opportunities for certain balancing

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[3] Balancing authority areas are control areas over which a balancing authority is responsible for certain grid-balancing activities such as matching supply and load and maintaining frequency. Often, electric utilities are balancing authorities over their service territory or BAA.

[4] There may also be similar inefficiencies in hybrid areas (BAA-to-RTO/ISO). However, many hybrid areas have established joint operating agreements (JOAs) to facilitate sharing of resources, typically energy in emergency situations but potentially economic energy sharing. A complete review of the scope of hybrid JOAs was not conducted for this report. The authors also note bilateral contracts and self-scheduled generation are common within RTO/ISO areas, complemented by economic dispatch.

services that may be needed closer to real time (e.g., 15-to-5-minute). Western states initially explored an energy imbalance market as a supplement to bilateral markets, which would provide a variety of benefits including automated employment of security-constrained economic dispatch for more efficient balancing services in real time (5-minute) (Federal Energy Regulatory Commission Staff 2013).

- **More Expensive Resources:** Bilateral trading requires more generators and other resources to meet the same level of reliability and other grid services (Tsoukalis et al. 2023). Sharing resources can help lower costs for consumers. Resource sharing groups, pooling, energy imbalance markets, and RTO/ISO markets are all tools that facilitate the sharing of certain resources over a wide geographic area. The Brattle report from South Carolina found the net benefits of joining a Southeast RTO would range from $115 million to $187 million per year whereas the net benefits of joining the existing PJM RTO would range from $281 million to $362 million per year (Tsoukalis et al. 2023). These savings would accrue from more efficient operations—for example, through security-constrained economic dispatch and coordinated scheduling—but approximately 63% to 82% of the total Southeast RTO savings and 55%–56% of the total PJM RTO savings would accrue from avoided capital investments.

These issues may lead to underutilization of existing transmission capacity or uneconomic trading outcomes.

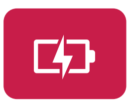
3 Barriers and Opportunities To Realize Transmission Value

To understand the reported symptoms of inefficient transmission use and the implications for the value transmission can provide to the system, we analyzed market, regulatory, and operational practices for transmission operation across the United States. The following sections present the barriers to achieving transmission value that are common across all regions and those specific to nonmarket, hybrid, and market regions. For each barrier, we identify the potential source of system value—capital costs, operating costs, reliability, resiliency—that could be impacted as well as potential options to address the barrier(s).

The following symbols are used to indicate each type of transmission value:


Avoided Capital Costs


Avoided Operating Costs


Improved Reliability


Improved Resiliency

3.1 Common Barriers

Though there exists a variety of power sector structures across the United States, some operational and regulatory barriers to the efficient use of interregional transmission are common to all interregional transactions, including market, nonmarket, and hybrid (market-to-nonmarket) regions.

3.1.1 Absence of Resource Adequacy Sharing Framework

Interregional transmission can enable neighboring systems (e.g., BAAs, RTOs/ISOs) to share energy in emergency situations for reliability or in nonemergency situations to lower costs and can facilitate access to lower-cost capacity for resource adequacy. However, a variety of factors may limit or disincentivize the use of interregional transmission to meet resource adequacy requirements.[5] Although each region may take a different approach, in general, external capacity resources with firm delivery commitments are considered added capacity resources for purposes

[5] It is noted FERC has approved both restrictive approaches to transmission deliverability requirements for capacity resources (e.g., PJM's pseudo-tie requirement in Docket No. EL17-1138-000) and more permissive transmission deliverability requirements for capacity resources (e.g., the Western Resource Adequacy Program in Docket Nos. ER22-2762-000 and ER22-2762-001).

of calculating a planning reserve margin whereas firm exports are subtracted (National Association of Regulatory Utility Commissioners 2021; Pfeifenberger et al. 2013; Caravallo et al. 2023). The resource adequacy treatment of nonfirm intertie benefits, which are not guaranteed or obligated to appear, is less uniformly applied (Pfeifenberger et al. 2013). For example, the value of interties for reserve margin calculations may be estimated using a variety of methods including maximum intertie ratings, performing a probabilistic assessment of intertie capability, or adjusting intertie capability based on load diversity across neighboring regions or expected external supply availability (Pfeifenberger et al. 2013).

In general terms, generation resource adequacy planning responsibility can rest with state regulators or RTOs/ISOs, depending on the jurisdiction (National Association of Regulatory Utility Commissioners 2023).[6] FERC and North American Electric Reliability Corporation (NERC) monitor and report on generation resource adequacy requirements for reliability[7] along with the adequacy of transmission resources and many other aspects of reliability service functions (e.g., operations, planning, interchange, and so on). NERC-registered resource planners develop resource adequacy plans for their planning areas by incorporating plans from state regulators or RTOs/ISOs and assessing commercial opportunities. NERC balancing authorities are tasked with balancing supply from capacity resources with demand whereas NERC reliability coordinators assist the balancing authorities in real time, including the ability to curtail interchange if needed. In its annual reliability assessments, NERC considers firm and expected imports/exports and operational risks that could impact reliability (North American Electric Reliability Corporation 2018). One of many factors that may prompt regions to take a conservative approach on the role of interregional transmission in providing resource adequacy benefits is the deliverability uncertainty that may arise between generation and transmission resource adequacy planning and actual system operations.

[6] This generalization excludes federal power marketing agencies and municipal or rural cooperatives.
[7] In general terms, FERC reviews, approves, and enforces reliability standards developed by NERC. NERC does not develop standards for resource adequacy.

OPPORTUNITIES

Deliverability uncertainty may discourage the use of capacity sharing through interregional transmission for resource adequacy. To explore the conditions under which greater capacity resource sharing through interregional transmission may occur:

⇒ NERC can consider supplementing its three existing reserve sharing groups in the operations horizon (i.e., contingency, frequency response, and regulation)[1]—which allow balancing authorities to share resources under specific terms and conditions—with guidelines and best practices for resource planners and planning coordinators to share capacity for resource adequacy in the planning horizon. In this context, resource adequacy sharing could include a generation resource being able to provide capacity in more than one area (without double counting).

⇒ Willing entities could voluntarily establish a resource adequacy sharing framework, such as the developing Western Resource Adequacy Program (WRAP), that addresses capacity and transmission deliverability requirements for sharing resources between BAAs and/or RTOs/ISOs. For example, FERC has approved WRAP's requirement that participants show they have NERC Priority 6 or 7 firm point-to-point or network integration transmission service necessary to deliver 75% of its forward capacity requirement (with certain exceptions). The remaining 25% of required transmission service must be obtained prior to serving obligations in an operating day. FERC believes this approach balances the need to ensure deliverability while providing flexibility to participants. However, because this is a new construct, FERC is requiring rigorous reporting on the implementation of the forward transmission demonstration and exceptions to monitor and determine the performance of this new framework (FERC 2023).

[1] Examples of existing NERC reserve sharing programs include Western Power Pool's contingency reserve sharing program (Western Power Pool 2023a) and frequency response sharing program (Western Power Pool 2023b).

3.1.2 Operating Practices During Extreme Weather Events

The ability to improve system reliability during nonstandard operating conditions is often cited as a benefit of interregional transmission (Millstein et al. 2022; Chang, Pfeifenberger, and Hagerty 2013). However, many regions lack operational studies and procedures to maximize the benefits of interregional transmission when these conditions arise. NERC regional entities have raised concerns about the need for interregional transfers during extreme weather events, the ability of the transmission system to accommodate these transfers, and the need for increased coordination, operational preparedness, and planning.

In its 2023 Summer Reliability Assessment Report, the Southeastern Electric Reliability Corporation (SERC) evaluated the adequacy of resources and transmission to meet the 2023 summer peak and found under normal conditions the region could meet demand with an adequate reserve margin and no transmission concerns (SERC Reliability Corporation 2023).

However, under an extreme weather scenario (i.e., extreme heat) where 6 gigawatts (GW) of nonfirm power transfer would occur from MISO to the SERC East subregion, power flow analysis indicated multiple system violations leading to system collapse in SERC's Central, East, and Southeast subregions as well as the MISO-South subregions (see yellow arrows in Figure 4). SERC concluded the extreme weather scenario with high power transfers highlight the importance of planned coordination and communication among reliability coordinators and BAAs to maintain reliability when large, unplanned power transfers are needed.

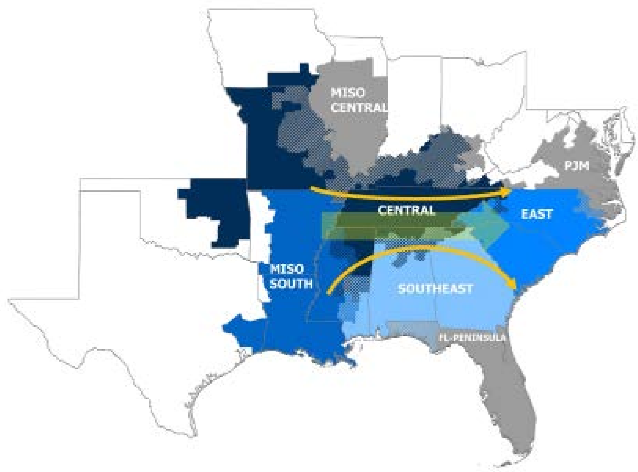


Figure 4. SERC 2023 Summer Reliability Assessment

Transfer impacts from MISO to SERC East where yellow arrows indicate areas of potential system collapse (SERC Reliability Corporation 2023)

The Midwest Reliability Organization's 2022 Regional Winter Assessment and 2023 Regional Summer Assessment both pointed to the need for increased transfers from neighboring utilities to maintain reliability in extreme weather conditions. The Winter Assessment found extreme winter conditions may result in insufficient capacity to meet extreme winter peak; the Summer Assessment found above-normal peak load and unplanned outages could result in MISO and SPP being at high risk for implementing emergency actions and relying on demand response programs and short-term power transfers from neighboring utilities (Midwest Reliability Organization 2023).

In addition to congestion at border seams, internal congestion within a system can limit power flows from moving through or out of that system or from moving into a neighboring system (see Section 3.1.3). During the February 2021 cold snap that impacted Texas and the Midwest, PJM notes it engaged in record levels of interchange, exporting power to MISO and other neighbors with reliability needs (PJM Interconnection 2023a). PJM states congestion management along its border seams played an important role in enabling power transfers. However, PJM had additional energy available for transfer that could not be exported because of internal congestion (PJM Interconnection 2023a).[8]

[8] Some of these internal constraints during the February 2021 cold snap are detailed in the FERC/NERC/Regional Entity cold weather report (FERC-NERC-Regional Entity Staff 2021).

OPPORTUNITIES

The inability to anticipate, operationally adjust, and solve for atypical constraints that may occur from abnormal flows during large transfer events may unnecessarily limit the value of interregional transmission. To enable transmission systems to accommodate large transfers during extreme events:

- ⇒ Neighboring reliability coordinators, BAAs, and transmission operators could perform joint studies on how such transfers may occur. This follows recommendations from staff members of FERC, NERC, and certain NERC regional entities after a cold-weather-related bulk power system outage in Texas and South Central United States in February 2021 (FERC-NERC-Regional Entity Staff 2021).
- ⇒ These studies could include seasonal transfer studies and sensitivity analyses that model large power transfers to determine where constraints exist that cannot be mitigated (FERC-NERC-Regional Entity Staff 2021).
- ⇒ These sensitivity scenarios could include import/export limits during stressed conditions and atypical flow patterns that could occur during extreme weather events and incorporate current and potential future conditions.
- ⇒ Neighboring systems could collaborate to address potential transmission bottlenecks within regions and ensure a level of import/export capability *within* individual systems to accommodate large transfers during extreme weather conditions (PJM Interconnection 2023a).
- ⇒ Reliability coordinators, BAAs, and transmission operators could perform system studies to determine if internal networks can accommodate anticipated levels of power flows with neighboring systems during extreme weather conditions.
- ⇒ These studies could consider input on the level of imports and exports estimated from neighboring transmission system operators as well as internal estimations.
- ⇒ These studies can be used to develop operator simulator training scenarios and new operating procedures for abnormal, high transfer scenarios and can be incorporated into operator drills.

3.1.3 Internal Transmission Capacity To Accommodate Large Transfers

As the contribution of variable renewable energy increases, grid operators may need an expanded set of tools to maintain system reliability. These tools include an increased ability to import and export power to maintain supply/demand balance and reduce curtailments. Although interregional transmission capability to enable imports/exports is often the focus, grid operators may increasingly need to consider internal transmission system sufficiency to accommodate external transfers.

The Western Electricity Coordinating Council's (WECC's) 2022 Assessment of Resource Adequacy report found all WECC subregions currently rely on imports for resource adequacy. Over the next 10 years, each WECC subregion is predicted to see an increase in resource adequacy risk and system variability because of increased variability in demand and energy imports (Western Electricity Coordinating Council 2022, 4).[9] In addition, the need to ensure sufficient internal transfer capacity to facilitate power exchange is expected to increase in WECC. The California Independent System Operator (CAISO) subsequently found supply imports required to serve load may need to be wheeled through other transmission systems before reaching ISO. This is also an issue for external load-serving entities currently reliant on CAISO exports to meet demand.

Renewable energy curtailment related to internal transmission constraints is another lens through which to understand this issue. In 2022, there were 4.4 million MWh of wind curtailments in MISO, and over 10 million MWh of wind curtailment in SPP, representing 9% of total wind generation in SPP (Wilson 2023). Internal congestion may be an issue if interregional transfer capability is available to the destination system, but internal congestion prevents the movement of resource adequacy resources through the original system.

OPPORTUNITIES

Internal transmission system constraints may inhibit large power transfers from interregional transmission, leading to resource adequacy concerns. To prepare and plan for levels of imports and exports:

⇒ Multiregion areas such as the Western Interconnection could evaluate both resource and transmission adequacy in a coordinated, wide-area fashion to plan a system that can more effectively manage increased variability (WECC 2022).

⇒ The NERC Interregional Transfer Capability Study and similar evaluations could examine 1) how transfer capacity needs may change as the share of variable renewable energy increases and 2) interventions to mitigate barriers to trade identified in its 2023 report (NERC 2023).

⇒ Nonmarket areas can explore solutions such as the Western Resource Adequacy Program proposed by Western Power Pool that aim to facilitate regional sharing of resource adequacy resources while maintaining the existing bilateral trading regime (Western Power Pool 2023d).

⇒ Interregional initiatives such as the Western Transmission Expansion Coalition and the Western States Transmission Initiative can be used to address the slow pace of regional and interregional transmission development (Western Power Pool 2023c; Gridworks 2023).

[9] WECC's assessment report measures resource adequacy risk using a demand-at-risk indicator (DRI) that identifies the number of hours in a year where demand is at risk (i.e., the potential for load shed). System variability is measured with a planning reserve margin indicator that evaluates the planning reserve margin needed for a specific resource portfolio to meet a loss of load probability that should not exceed 2.4 hours in a year.

3.2 Barriers Between Nonmarket or Hybrid Areas

In nonmarket and hybrid areas, the design of interregional transactions and methods to manage congestion and share information present unique challenges to the efficient use of interregional transmission.

3.2.1 *Uncoordinated Bilateral Trading*

Uncoordinated bilateral trading between nonmarket and hybrid areas (e.g., market to nonmarket) typically occurs through bilateral contracting processes. Although pragmatic for other reasons, these uncoordinated transactions may lead to inefficient use of interregional transmission capacity, as discussed in depth in Section 2.2.3. These inefficiencies result from reasons including rate pancaking, friction to trading, limited real-time options, higher resource costs from inability to share, and lack of transparency. Absent ameliorating solutions, trading between nonmarket BAAs or trading between nonmarket BAAs and RTOs/ISOs lacks coordination efficiencies on several scales:

- Reserve sharing for reliability (intrahour), for example, sharing of reserves and intrahour and hourly economic dispatch
- Resource sharing to lower operational costs (hourly, daily), for example, day-ahead unit commitment and real-time security-constrained economic dispatch
- Long-term planning to lower capital costs (multiyear), for example, forward capacity procurement and long-range transmission expansion planning.

Improving coordination mechanisms that facilitate trading between nonmarket BAAs and between hybrid areas can improve reliability and resilience and lower consumers' costs.

OPPORTUNITIES

Relying upon bilateral trading may lead to inefficient use of generation and transmission resources to meet system needs. To retain the commercial benefits of bilateral contracts while maximizing the efficient use of generation and transmission infrastructure:

⇒ Regions could consider adopting a coordinated scheduling platform where information is exchanged and software programs are used to reduce the time and effort it takes to identify trading partners and improve asset utilization. Examples of coordinated scheduling include energy imbalance markets, facilitated bilateral exchanges, and dynamic scheduling. Examples of real-time energy imbalance markets include the Western Energy Imbalance Market and Western Energy Imbalance Service. Day-ahead coordination platforms are being developed, such as the Extended Day-Ahead Market and the SPP Markets Plus. Such a platform should support long-standing principles espoused by FERC, for example, open-access, transparency, cost competition, and protection against market manipulation.

⇒ Regions could consolidate nonmarket BAA operations to an RTO/ISO to improve real-time and day-ahead scheduling. This could also provide wider-area resource adequacy procurement, regional transmission planning, and independent market monitoring.

More information on these options can be found in *Balancing Area Coordination: Efficiently Integrating Renewable Energy into the Grid* (National Renewable Energy Laboratory 2015).

3.2.2 Congestion Management

RTOs/ISOs use security constrained economic dispatch to automatically adjust generation output to manage congestion in real-time operations. Across nonmarket and hybrid areas where security-constrained economic dispatch is not available, imperfect congestion management can reduce the efficient use of interregional transmission to meet electricity demand at lowest cost.

Eastern Interconnection Transmission Loading Relief

Across the Eastern Interconnection, transmission loading relief (TLR) procedures are called upon in real-time operations to control flows on overloaded transmission lines that move power from one system to another.[10,11] In general, a TLR is used to control congestion on lines between nonmarket areas or lines between a nonmarket area and an RTO/ISO. Only NERC reliability coordinators can implement TLRs, which represent direct measures of interregional transmission constraints in terms of MW overloading (e.g., system operating limit or interconnection reliability limit violations). There are various levels of TLRs, with Levels 3a and above resulting

[10] For more information, see NERC Reliability Standards IRO-006-5 at https://nercstg.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-5.pdf and IRO-006-EAST-2 at https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-EAST-2.pdf.

[11] This section explores historical issues with TLRs and does not account for potential implementation of parallel flow visualization (PFV) provisions in FERC Order 676-J (May 20, 2021) that have the potential to improve the efficiency of Eastern Interconnection congestion management.

in curtailment (i.e., a reduction in transmission service) of previously agreed-upon transmission service. As a result of market reforms and transmission investments, the level of TLR relief has steadily decreased over time (Figure 5) (U.S. Department of Energy 2020, 13–14).

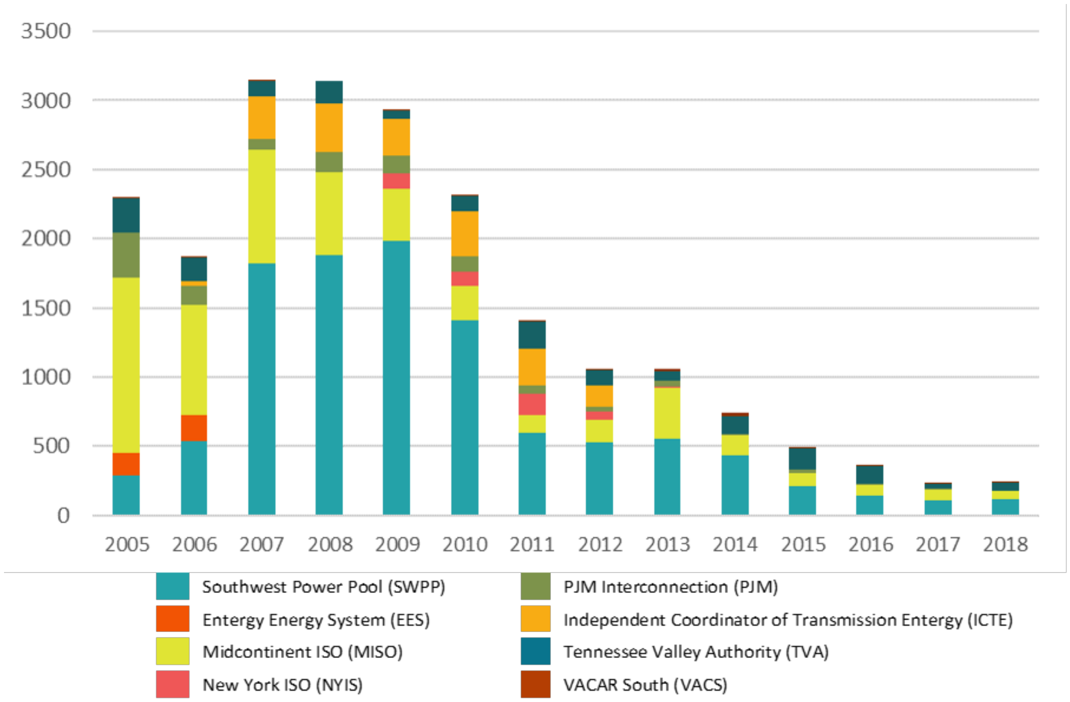


Figure 5. Total TLRs (Levels 3, 4, and 5) by reliability coordinator (2005–2018)

Source: U.S. Department of Energy (2020)

For RTOs/ISOs, TLRs are often called to manage flows related to external nonmarket BAAs, where market-to-market coordination and economic redispatch are not used to manage congestion. In 2022, NYISO had 156,209 MWh of curtailments related to TLR Level 3a and above calls,[12] MISO had 29,771 MWh, and PJM had only 299 MWh (Monitoring Analytics, LLC 2023, 519). The MISO market monitor notes TLRs called by external entities that result in transaction curtailments create price spikes in MISO that are passed on to MISO consumers with no reimbursement (Potomac Economics 2023c, 69–70; 95).

Across the Eastern Interconnection, the Tennessee Valley Authority was associated with the greatest number of TLR calls at Level 3a and higher in 2022. The MISO market monitor estimates generation from the Tennessee Valley Authority could have relieved $63 million in congestion costs from TLR constraints, while Associated Electric Cooperative Inc. generation could have relieved $43 million in TLR-related congestions costs (Potomac Economics 2021, 73).

[12] This represents less than 0.1% of NYISO's total forecasted volumes of 156,7000,000 MWh for 2023; see https://www.nyiso.com/documents/20142/32669344/2023-Schedule-One-Posting-for-posting-with-detail.pdf/840e952d-8555-a853-8d46-33a05cba1911 (accessed December 7, 2023).

Western Interconnection Qualified Paths

Portions of the non-RTO/ISO Western Interconnection—operated by 38 separate BAAs—rely on manual coordination with generators, transmission operators, and neighboring BAAs for congestion management (U.S. Department of Energy 2023, 36). In 1995, FERC approved the Unscheduled Flow Mitigation Plan (UFMP), which has been revised over time, to manage unscheduled flows among and across BAAs in the Western Interconnection. This plan identifies transmission "qualified paths" that have a history of significant congestion bottlenecks. Phase shifters and other devices, as well as curtailments, are used on these qualified paths to mitigate the impacts of unscheduled flows (Southwest Power Pool 2019b).

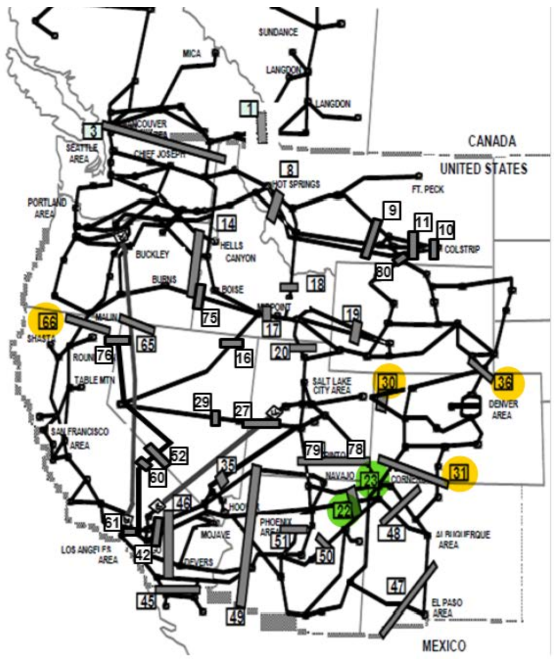


Figure 6. Approximate location of current (yellow) and former (green) qualified paths in the Western Interconnection UFMP

Source: WECC (2013)

As shown in Figure 6, there are four qualified paths and six qualified controllable devices (all phase shifting transformers) in the Western Interconnection (Western Electricity Coordinating Council 2013).[13] The current qualified paths pose a reliability risk across the region if congestion across multiple parallel paths prevents west-east power transfers. Phase shifters can be useful to create capacity on parallel paths, but these technologies are best suited for congestion relief with low congestion volatility. As the share of variable renewables increases, these technologies may be a less effective congestion management solution (U.S. Department of Energy 2023, 36). Utilities have expressed interest in qualifying new paths into UFMP but note the challenges

[13] See a current list of qualified paths and devices on SPP's website at https://spp.org/documents/58826/current%20list%20of%20qualified%20devices%20&%20paths_062520.pdf (accessed October 11, 2023).

associated with meeting the data requirements specified in the UFMP tariff.[14] In addition, transmission expansion in the western portion of the interconnection may need to be coupled with upgrades on the eastern portion to ensure reliability because of these unscheduled flows (U.S. Department of Energy 2023, 36).

Coordinated interconnection-wide transmission planning and market integration could help solve these issues. In the interim, subregions of the interconnection have established their own enhanced congestion management scheme to minimize local congestion impacts. In 2014, CAISO launched its western energy imbalance market (WEIM) that operates parallel to the UFMP. SPP's western energy imbalance service (WEIS) was launched in 2021 to, among other things, manage congestion within its internal footprint. Both WEIS and WEIM interact with UFMP facilities. For example, congestion management within WEIS or WEIM can support scheduled flow that might otherwise be curtailed through the UFMP (CAISO 2022, 43). However, WEIM and WEIS primarily manage congestion over real-time transactions. Real-time markets generally deal with a much smaller volume of transactions (e.g., 5%), whereas day-ahead markets schedule the majority of market volumes (e.g., 95%). The real-time only approach is simpler to implement, but also leaves opportunities to improve upon bulk power system visibility and congestion management.

OPPORTUNITIES

Imperfect congestion management between nonmarket and hybrid regions can pose reliability risks and reduce the efficient use of interregional transmission to meet electricity demand at lowest cost. To improve congestion management in areas where security-constrained economic dispatch is not available:

⇒ Regions in the Eastern Interconnection can adopt joint operating agreements with neighboring systems that most frequency call TLRs to specify congestion management solutions that are more economically efficient (Potomac Economics 2023c, 70).

⇒ The Western Interconnection could explore interconnection-wide integration of the UFMP paths and process into the coordinated scheduling process of WEIM and/or WEIS. This could be accompanied by reevaluating program design to allow for additional path qualification.

⇒ The UFMP operational process could be accompanied by a transmission planning process that could help ensure balance between eastern and western transmission upgrades to manage unscheduled flows.

[14] For a brief discussion of the challenges with adding a qualified path, see SPP's Unscheduled Flow Committee meeting minutes of August 15, 2023 at https://www.spp.org/documents/69962/ufc%20meeting%20minutes%2020230815.pdf; for a list of the current path qualification and disqualification requirements, see SPP's WIUFMP's administrative procedure manual at https://www.spp.org/documents/62012/wiufmp%20administrator%20procedure.pdf.

3.2.3 Inconsistent Available Transfer Capability Methods and Assumptions

Available transfer capability (ATC) is a measure of the transmission transfer capability available for potential commercial transaction after all committed uses are considered.[15] FERC Order No. 890 requires public utilities to calculate their ATC and make these values public through its Open Access Same-Time Information System to give potential third-party customers information about available transmission.[16] Order No. 890 also requires these public utilities to disclose their methodology, inputs, and assumptions for calculating the ATC in their open access transmission tariff. In Order No. 890, FERC found a lack of ATC transparency and consistency throughout the industry created opportunities for undue discrimination and directed NERC and the North American Energy Standards Board (NAESB) to work with industry to develop standard ATC calculation methods, definitions, data inputs, assumptions, and information exchanges to be implemented across the industry.[17] Order No. 890 also requires neighboring public utility transmission providers to coordinate in calculating and posting ATC values for facilities along their borders.[18] In 2020, FERC Order No. 676-I[19] adopted NAESB's Wholesale Electric Quadrant Standards for Business Practices and Communication Protocols for Public Utilities, which includes standards for ATC consistency and transparency and is updated occasionally, most recently in June 2021.

Despite these efforts, certain transmission-dependent utilities—all cooperatives that operate in North Carolina, Texas, or Florida—filed comments in response to FERC's April 2022 Notice of Proposed Rulemaking on regional transmission planning and cost allocation, asserting greater transparency and consistency is still needed for ATC values posted along neighboring transmission system seams.[20] These commenters state they have experienced neighboring transmission service providers posting different ATC values for the same intertie, potentially suggesting these providers are using different methods or assumptions in their ATC calculations.[21] These utilities note although Order No. 890 required coordination between neighboring transmission systems, it did not require the two neighbors to agree on a single set of ATC values. Similarly, FERC Order No. 1000 established interregional transmission coordination and cost allocation but did not mandate the use of similar models and input data for transactions across seams. These stakeholders suggest consistency has not been achieved through coordination alone, and if consistency is not possible, greater transparency is needed to enable the detection of undue discrimination.

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[15] NERC defines ATC as "A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows."

[16] Order No. 729 (2009) and subsequent revisions approved several modeling, data, and analysis reliability standards developed by NERC for calculation of ATC on flowgates.

[17] Order No. 890, 118 FERC ¶ 61,119, paragraphs 196, 207.

[18] Order No. 890, 118 FERC ¶ 61,119, paragraphs 327, 348.

[19] FERC Order No. 676-I, Standards for Business Practices and Communication Protocols for Public Utilities, available at https://www.ferc.gov/sites/default/files/2020-08/01-23-2020-E-23.pdf.

[20] See Notice of Proposed Rulemaking comments from transmission-dependent utilities in Docket RM21-17-000 located at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=FF30F745-22F3-C3CF-AA63-82ADA3A00000.

[21] The commenters also note there could be legitimate reasons for differing ATC values.

OPPORTUNITIES
Inconsistent ATC values can result in underutilized or oversubscribed transmission lines. To improve communication regarding ATC:

⇒ Regional or national entities could consider action to require or recommend neighboring providers agree on a single set of ATC values and/or greater transparency and monitoring of ATC calculations.

⇒ Neighboring transmission operators could perform joint studies on ATC calculation methods to arrive at a mutually agreed-upon method or, at a minimum, be able to recreate the values calculated by neighboring regions using their selected method.

3.2.4 Wheel-Through Priority for Reliability Imports

A key potential benefit of interregional transmission is the ability to increase system resiliency through access to more resources able to respond during emergency conditions. Though some RTOs/ISOs have mechanisms in place to set aside transmission transfer capacity needed to serve load in emergency conditions or contingencies (e.g., capacity benefit margin), others—such as CAISO—do not. CAISO manages grid schedules through the day-ahead and real-time markets and offers only one classification of transmission service. If there is insufficient transmission capacity to support intertie transactions, CAISO prioritizes market-based transactions and curtails self-scheduled resources in priority order based on preestablished criteria. And CAISO's transmission planning processes do not account or plan for wheel-through transactions other than preexisting firm entitlements.[22] During the heat wave on August 14 and 15 of 2020, CAISO operators called on load-serving entities to curtail load. One contributor to this load-shedding event was a large volume of exports scheduled in the day-ahead market that were not part of wheel-through transactions or capacity contracts with internal CAISO resources (CAISO Department of Market Monitoring 2020).

WECC'S 2020 Western Assessment of Resource Adequacy Report noted absent the ability to import supply to meet demand, all WECC subregions would have some amount of unserved load over the next 10 years (Western Electricity Coordinating Council 2020). CAISO subsequently found supply imports required to serve load may need to be wheeled through other transmission systems before reaching the ISO. This is also an issue for external load-serving entities currently reliant on CAISO exports to meet demand. Recognizing the need to have mechanisms in place to set aside transmission transfer capacity needed to serve load in emergency conditions or

[22] See FERC's Order in Docket ER21-1790 related to CAISO'S proposed revisions to its open access transmission tariff on wheeling priorities at https://www.caiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf (accessed December 21, 2023).

contingencies, CAISO is working to develop a long-term framework to support priority wheel-through scheduling.[23]

SOLUTION OPTIONS

Regional practices to prioritize market transactions, even during emergency conditions, can reduce system reliability. To ensure system reliability while also preparing anticipated increases in power wheeling among regions:

⇒ CAISO can change the scheduling priorities placed on native load relative to self-scheduled exports and wheel-through schedules across the ISO BAAs (CAISO Department of Market Monitoring 2020).

⇒ CAISO can implement its approved solution to establish wheel-through scheduling priority by calculating ATC in monthly and daily increments, establishing a mechanism to access and reserve ATC, a pathway for entities to request transmission expansion studies and upgrades to accommodate long-term wheel through scheduling priority, a curtailment protocol that considers the scheduling priority and load, and a compensation mechanism for wheel-through priority scheduling (CAISO, 2023a).

3.3 Barriers Between Market Areas

The barriers to realizing interregional transmission value identified in this section occur between RTO/ISO markets. Joint operating agreements between neighboring RTOs/ISOs identify agreed-upon terms, conditions, and programs for various aspects of interregional coordination. The following sections explore the efficacy of various programs established in RTO/ISO joint operating agreements, including coordinated transaction scheduling for economic trading (Section 3.3.1), market-to-market coordination for congestion management (Section 3.3.2), and interface flows and pricing (Section 3.3.3). The remaining sections explore merchant HVDC operations and other RTO-specific issues.

3.3.1 Coordinated Transaction Scheduling

Coordinated transaction scheduling (CTS) refers to procedures for neighboring RTOs to exchange market information and schedule interchange transactions primarily for economic purposes (e.g., to lower costs). In theory, CTS should enable interfaces to be more efficiently used. In practice, challenges such as inaccurate price forecasting and high transaction fees undermine the effectiveness of the CTS system.

PJM, MISO, and ISO-NE have CTS agreements, but only the CTS between NYISO and ISO-NE results in significant participation and production cost savings (Figure 7) (Potomac Economics 2023b, 9). The MISO Market Monitoring Unit (MMU) asserts high transaction fees and

[23] See the “Transmission service and market scheduling priorities” initiative on the CAISO stakeholder website at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Transmission-service-and-market-scheduling-priorities (accessed October 10, 2023).

persistent price forecasting errors likely hinder the use of CTS and push traders toward traditional transaction scheduling (Potomac Economics 2023c, 90).[24]

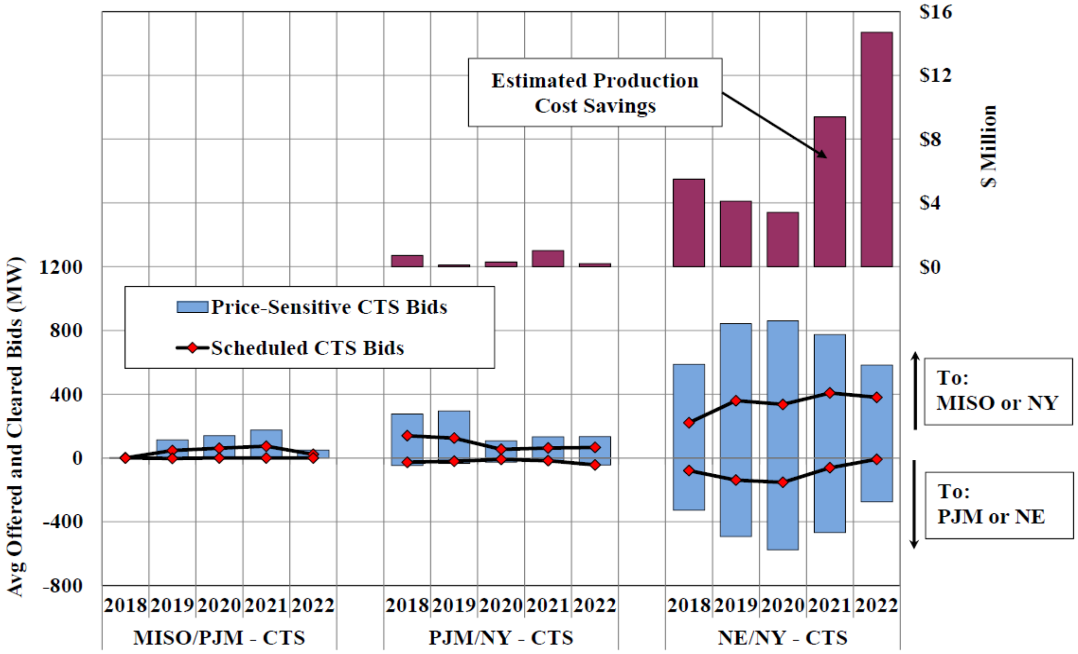

Figure 7. CTS scheduling and efficiency (2018–2022)

(excludes PCS estimate for MISO/PJM because of low participation)

Source: Potomac Economics (2023b)

The ISO-NE external MMU attributes the low CTS participation in MISO/PJM and PJM/NYISO to high transaction fees at these interfaces. Though there are no significant transmission or uplift charges at the ISO-NE/NYISO interface, the NYISO/PJM interface can see charges ranging from \$6–\$8 per MWh whereas the MISO/PJM interface can see \$0.75/MWh reservation charges and an additional \$1.75/MWh for cleared quantities. The ISO-NE external MMU also notes transactions from PJM to MISO or NYISO incur a smaller charge (\$1–\$2/MWh) than transactions in the opposite direction, leading to more activity in the PJM export direction (Potomac Economics 2023b, 9). The NYISO MMU notes over a 4-year period (2019–2022), the average number of price-sensitive bids cleared at the NYISO/ISO-NE interface was 4 times greater than the number of cleared bids at the PJM interface, attributed to higher transaction fees with PJM (Potomac Economics 2023a, 125).

Poor price forecasting poses another challenge to CTS trading. CTS bids are cleared based on the forecast difference in interface prices. CTS transactions are scheduled based on the RTO/ISO forecasts of real-time prices, the CTS interface price spreads between markets, and the market participant's bids. If the market participant's bid is lower than the interface price spread, the transaction is cleared. However, as shown in Table 1, real-time price differences between RTOs/ISOs can be extremely volatile—making accurate forecasting and scheduling a challenge (Monitoring Analytics, LLC 2023, 504).

[24] For example, hourly scheduling in 60-minute intervals based on locational marginal prices.

Table 1. Volatility in CTS Interface Price Differences Between Day-Ahead and Real-Time Scheduling (2022)

Source: Monitoring Analytics, LLC (2023)

CTS Interface	Average (Absolute Value) Interval Price Differences ($/MWh)		Number of Times per Day Price Difference Changes Signs	
	Day-Ahead	Real-Time	Day-Ahead	Real-Time
PJM/NYISO	12.94	115.36	3.1	47.9
PJM/MISO	9.09	97.64	4.1	62.9

In the day-ahead markets, the average absolute value of the interval price differences between PJM and NYISO was less than $13 and changed signs (i.e., from positive to negative or vice versa) more than 3 times per day. Between PJM and MISO, the difference was more than $9 and changed signs more than 4 times per day.

In the real-time market, the average absolute value of the price difference across PJM/NYISO was over $115 and changed signs almost 48 times per day. Between PJM and MISO, the price difference was over $97 and changed signs almost 63 times per day. The increased price volatility in real time highlights the challenge of accurate price forecasting. Because CTS participants bear the risks associated with high price forecast errors, this likely discourages participation.

The ISO-NE external MMU attributes better price forecasting as a factor that facilitated greater participation and savings in the ISO-NE/NYISO CTS compared to the other RTO CTSs shown in Figure 8. The ISO-NE external MMU states ISO-NE uses seven interchange levels to forecast its supply curve whereas PJM uses only one interchange level for its forecasts (Potomac Economics 2023b, 10). Despite the seemingly better performance of the ISO-NE/NYISO CTS, the internal ISO-NE MMU noted in 2022 the average absolute forecast error for the ISO-NE/NYISO CTS increased to ±$23.87/MWh. This was more than double the 2021 value ($10.78/MWh) and indicates the CTS forecasts became less accurate (ISO-NE Internal Market Monitor 2023, 163).[25] This leads to inefficient hedging day-ahead and real-time strategies from market participants that inhibit the CTS from adjusting to actual price changes that occur in real time—for example, scheduling in the day-ahead market where there is no forecasting error, then offering low-priced, price-insensitive bids in the real-time market. The NYISO market monitor also notes differences in real-time commitment and real-time dispatch prices indicate the commitment scheduling decisions (for external resources and fast-start units with lead times of 15 minutes to 1 hour) may be inefficient (Potomac Economics 2023a, 127).

In an optimal system, when prices between market areas are different, power would flow from the lower-priced area to the higher-priced area until prices converge or a physical constraint is hit (e.g., ramp or total transfer capacity limit). As shown in Figure 3 (Section 2.2.2), the ISO-

[25] The ISO-NE's Internal Market Monitor 2021 Annual Markets Report noted the average absolute forecast error for the CTS increased from ±$6.34/MWh in 2020 to ±$10.78/MWh in 2021. See the 2021 Annual Markets Report at https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf (accessed March 20, 2024).

NE/NYISO CTS does not operate optimally. For example, in 6% of the periods when there was a $50–$100/MWh price difference, there was on average about 200 MW of unused interface capacity between ISO-NE and NYISO (ISO-NE Internal Market Monitor 2023). The CTS processes have been criticized by market monitors for a least a decade, with several calling for the replacement of the CTS with intertie optimization (Johannes Pfeifenberger et al. 2023, 8). Though existing CTS processes could be improved, the absence of a CTS is suboptimal. Reviewing historical prices differences along the SPP/MISO seam, the SPP MMU estimated intermarket inefficiency to be worth $9.4 million to $11.2 million, and a portion of this could be captured by establishing a CTS along this seam (SPP Market Monitoring Unit 2020).

OPPORTUNITIES

Uncertain price forecasting, high transaction fees, and other issues have limited the ability of CTS to efficiently use interregional transmission. To improve interregional transaction scheduling:

- ⇒ Regions could reduce or eliminate CTS transaction fees and charges (Potomac Economics 2023b, 10).
- ⇒ Reducing the time interval for interchange adjustments based on real-time prices could improve price forecasting (Potomac Economics 2023b, 10). The MISO MMU estimates moving to a 5-minute CTS with PJM would have achieved over $40 million in production cost savings versus the actual $3 million achieved through the current process and $56 million in production cost savings by switching to a 5-minute CTS with SPP (Potomac Economics 2023c, 92). The ISO-NE internal MMU believes price forecasting error is unlikely to be completely eliminated and therefore changes to the CTS mechanism or settlement process could be pursued to better incentivize cost-based offers (ISO-NE Internal Market Monitor 2023, 167).
- ⇒ Replacing the CTS with an interchange optimization solution could also be considered (Monitoring Analytics, LLC 2023, 61).

3.3.2 Market-to-Market Congestion Coordination

RTOs/ISOs in the Eastern Interconnection generally use TLR and market-to-market (M2M) coordination to manage interregional congestion.[26] M2M congestion management programs allow RTOs/ISOs to jointly and cost-effectively manage transmission interties that can be impacted by the operation of both neighboring systems. This section explores M2M implementation issues between PJM and MISO and between MISO and SPP.

[26] This section does not explore changes or improvements to congestion management programs that could occur through potential implementation of PFV provisions through FERC Order 676-J (May 20, 2021).

MISO/PJM M2M: Firm Flow Entitlements

Under the PJM/MISO joint operating agreement, the RTOs jointly identify a portfolio of transmission facilities that impact both systems, then jointly operate these facilities. These jointly controlled facilities are called M2M flowgates. As of 2022, PJM had 197 flowgates eligible for M2M coordination, and MISO has 144 (Monitoring Analytics, LLC 2023, 515). PJM and MISO conduct a variety of studies to determine which flowgates they will monitor and control.[27] Flows along some of these facilities are limited based on 2004-era historic flows each RTO created on each flowgate, known as firm flow entitlements (FFEs) that are used in the settlement process. The FFE is the amount of flow each RTO is allowed to create on a facility before incurring redispatch costs based on the M2M process rules. If the RTO monitoring the intertie exceeds FFE flows in the real-time market (plus MW allowances from day-ahead coordination), the monitoring RTO must pay the nonmonitoring RTO and vice versa. One critique of this arrangement is FFEs based on 2004-era flows may not be appropriate for current operating conditions, leading to inefficient limits on M2M flowgates and excess payments from RTOs for violations. Figure 8 shows the management payments of each RTO related to M2M flowgate, with the spike in December 2022 related to Winter Storm Elliot (Monitoring Analytics, LLC 2023, 516). The MMU notes the RTOs and stakeholders recognize a modification to the freeze date model is needed and have been working on solutions for many years with no resolution (Monitoring Analytics, LLC 2023).

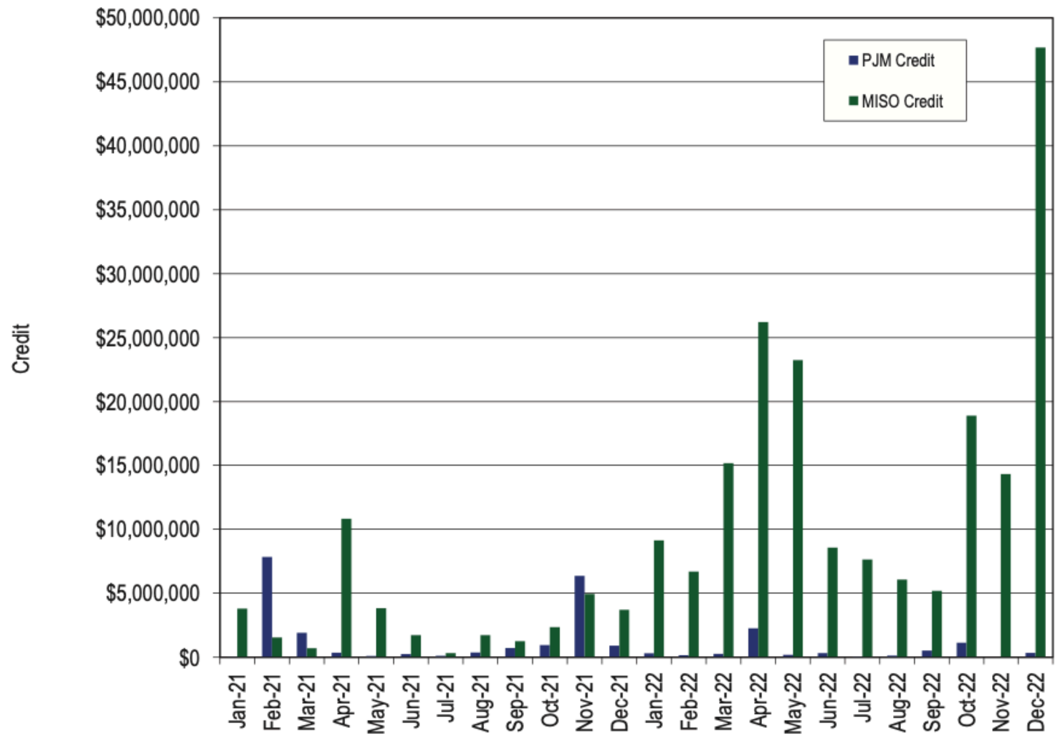

Figure 8. PJM/MISO credits for coordinated congestion management, Jan 2021–Dec 2022

Source: Monitoring Analytics, LLC (2023)

[27] A reciprocal coordinate flowgate is a flowgate that both PJM and MISO systems can impact, is controlled by either PJM or MISO, and is subject to M2M congestion management (e.g., transmission load relief).

Similar M2M coordinate flowgate management agreements are in place through the PJM/NYISO joint operating agreement, but this process relies on real-time market coordination and actual flows. This results in a more efficient process and, in 2022, there was no exchange of payments related to congestion management (Monitoring Analytics, LLC 2023, 517).[28] The PJM/NYISO joint operating agreement also includes an M2M process with entitlements for settlement purposes but, unlike the entitlement between PJM and MISO, these M2M entitlements on flowgates are calculated and compared at least once per year—unless there is mutual agreement not to recalculate in a given year.[29]

MISO/SPP M2M: Constraint Modeling Issues

The joint operating agreement between MISO and SPP requires each organization to model the other's M2M constraints in their day-ahead markets. In 2020, the MISO and SPP market monitors jointly conducted a series of seams studies for the Organization of MISO States and the SPP Regional State Committee, including a study on M2M coordination (Potomac Economics 2020a). Among other issues identified, the market monitors' analysis found SPP was either not modeling MISO's M2M constraints in the day-ahead market or modeling them in a way that prevents them from binding. This would cause SPP to inefficiently commit resources and increase costs to both regions (but more so to SPP) through M2M settlements. The MISO MMU found SPP congestion balancing costs to be consistently positive and 3 times greater than MISO costs, totaling $180 million over a 2-year period (Potomac Economics 2020a, 23). In 2022, SPP began a process to activate MISO M2M constraints in the day-ahead market.[30] SPP staff expressed concern that activating the MISO M2M constraints in the day-ahead market would exacerbate transmission congestion rights (TCR) underfunding (Southwest Power Pool Market Monitoring Unit 2023, 246).

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[28] The PJM/NYISO agreement also allows for joint operation of phase angle regulators (PARs) for flowgates at the seams, which in 2022 resulted in some exchange of PAR credit payments between the RTOs for congestion management.

[29] See Section 6 of Schedule D (Market-to-Market Coordination Process) of the PJM/NYISO joint operating agreement located on the PJM website at https://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx (accessed February 6, 2024).

[30] SIR75 Market-to-Market Improvements https://spp.org/search?q=%22SIR75%22&t=Documents (accessed August 11, 2023).

OPPORTUNITIES

Inefficient congestion management through outdated flow limits or inaccurate modeling can result in inefficient transmission use and excessive congestion balancing costs. To improve interregional congestion management:

⇒ The FFEs between MISO and PJM could be updated to reflect the current capability of the system as recommended by the PJM MMU. The PJM MMU asserts FERC could set a deadline for resolution to establish new FFEs if existing stakeholder consultations cannot reach a solution (Monitoring Analytics, LLC 2023, 516).

⇒ MISO and SPP could implement improved testing criteria for identifying M2M constraints for joint management, automate certain manual procedures for identifying and managing constraints, enhance software for short- and long-term relief requests, and model neighboring RTO constraints based on joint recommendations from the MISO and SPP MMUs (Potomac Economics 2020a). The MMUs identified $35 million in reduced annual congestion costs by automating processes to identify and activate constraints. In addition, the MMU-recommended software improvements to optimize the amount of relief requested on M2M constraints could result in $32 million of annual congestion benefits and $4 million in annual production cost savings.

⇒ Within SPP, ongoing efforts to align day-ahead and real-time congestion along the SPP/MISO seam along with modifying the transmission congestion rights funding model could reduce congestion payments and alleviate concerns about TCR underfunding (Southwest Power Pool Market Monitoring Unit 2023, 246).

3.3.3 Interface Flows and Pricing

This section explores issues related to physical locations where power flows are scheduled and the location where power transactions are priced. Flawed interface pricing can lead to operational inefficiencies such as loop flows and economic inefficiencies such as redundant charges. This section will draw from examples in PJM and MISO to illustrate these issues.

PJM Physical and Pricing Interfaces

A physical interface is an interconnection point between neighboring BAAs where imports or exports can be *scheduled* to flow. An interface pricing point determines the price assigned to the import or export transaction and is based on the *actual* physical path through which the energy flows. Market participants designate a scheduled path from generator (source) to load (sink) based on transmission reservations (e.g., considering transmission availability and cost) and identify this path on the NERC electronic tag.[31] However, because electricity flows on the path

[31] NERC's electronic tagging requirements for interchange transactions are generally described in standards INT-006-5 (Evaluation of Interchange Transactions) https://www.nerc.com/pa/Stand/Reliability%20Standards/INT-006-

of least resistance, the designated scheduled path through which the transaction is priced may diverge from the actual flow.

According to the PJM MMU, there are several issues with the current interface pricing scheme (Monitoring Analytics, LLC 2023, Sec. 9). First, the interfacing pricing points for all transactions with the Western Interconnection are assigned to one of two pricing points (MISO or SOUTH), based on geography rather than electrical impact. The interface prices are supposed to include weighting factors that are dynamically adjusted to reflect systems conditions. However, the weights are in fact static and modified only on occasion.[32] Therefore, interface prices do not reflect actual system conditions. A second issue is related to how PJM treats noncontiguous interface pricing points. For example, although there is no physical intertie between PJM and the Ontario Independent Electricity System Operator (IESO), PJM created the Independent Electricity Market Operator (IMO) interface pricing point to reflect the fact that transactions to or from the IESO balancing authority result in actual flows split between MISO and NYISO interface pricing points.

Issues with interface pricing have led to problems related to loop flows and concerns over sham scheduling within PJM. Loop flows are the difference between actual and scheduled power flows at an interface point and are a concern because they negatively impact LMP-based market efficiency, financial transmission rights revenue adequacy, and system operations. In 2022, PJM experienced 153 gigawatt-hours (GWh) of loop flows, less than 1% of total scheduled flows. However, some individual interfaces experiences very high inadvertent flows. The Northern Indiana Public Service interface experienced flows more than 16 times the scheduled amount (Monitoring Analytics, LLC 2023).

NERC tags require market participants to specify the complete transmission path from source to sink for transactions. According to the PJM MMU, market participants do not always include complete path information on the NERC tags. Sham scheduling is a method of scheduling where the market participant breaks a single transaction into multiple transactions to hide the true generation source for financial gain (Monitoring Analytics, LLC 2023, 522). For example, independent of the scheduled path, a transaction sourcing in NYISO and sinking in PJM would be priced in the energy market at the PJM/NYISO interface pricing point. A market participant could break the transaction into two segments, one from the NYISO/Ontario path and a second from the Ontario/MISO/PJM path. The origin of the transaction would be concealed, and PJM would price the transaction at the IMO interface pricing point. Sham scheduling could also occur by submitting transactions in opposing directions for portions of the larger transaction to take advantage of higher prices in a given direction without impacting actual power flows.

MISO Interface Pricing

Interface pricing in MISO includes a system marginal price, a marginal transmission loss component, and a congestion component. When an M2M constraint binds, both RTOs price and settle with external transactions based on their respective estimates of the entire congestion effects of the transaction, resulting in a rough doubling of the congestion settlement (Potomac

5.pdf and INT-009-3 (Implementation of Interchange) https://www.nerc.com/pa/Stand/Reliability%20Standards/INT-009-3.pdf.

[32] PJM began applying dynamic weighting factor to the Ontario pricing point in June 2015.

Economics 2023c, 94). In response to redundant congestion pricing, MISO and PJM implemented a “common interface” definition in 2017 that included 10 generator locations near the MISO/PJM seam with 5 in MISO and 5 in PJM. This method assumes power sources and sinks at specific buses along the seam border. In reality, the system’s marginal generators are not always located at seam buses but are located throughout the RTO area. For example, lower-priced marginal generators can ramp up in the source RTO area and provide power to export whereas higher-priced marginal generators throughout the sink area would ramp down. The MISO MMU found the common interface method exaggerates the effects of import and export flows on constraints at the seam, resulting in larger average price errors and volatility at the interface (Potomac Economics 2023c, 93).

MISO and SPP do not use the “common interface” definition and are still redundantly pricing congestion (Potomac Economics 2023c, 94). The MISO MMU has estimated this approximately doubles the congestion costs from the efficient level. This results in poor incentives for participants to schedule interchanges when M2M constraints are binding. The MISO MMU estimated of the time periods with M2M binding constraints, 60% of the time congestion costs were within $1 of the efficient level (i.e., the price that does not redundantly price congestion), 11% of the time they were overstated by more than $5, and in the remaining 29% of the time the congestion costs were more than $5 above the efficient level (Potomac Economics 2020b, 9). This method also raises costs for the RTOs. Costs increase, for example, when both RTOs are paying $10/MWh for congestion relief ($20/MWh in total). The nonmonitoring RTO would receive congestion relief valued at $10/MWh, and the monitoring RTO would revise dispatch and pay generation resources for congestion relief at an expected value of $10/MWh. However, the monitoring RTO has no M2M mechanism to recover these costs and is likely to charge to load as uplift. The MISO MMU estimated the cost of these excess payments and charges was over $7.5 million from 2018 to 2019 (Potomac Economics 2020b, 11).

OPPORTUNITIES

Issues with interface pricing can lead to operational inefficiencies such as loop flows, economic inefficiencies such as redundant charges, and opportunities for market manipulation through sham scheduling. To improve interface pricing:

⇒ A validation method for submitted transactions that requires market participants to submit transactions on paths of expected actual power flow to reduce unscheduled loop flows could be implemented (Monitoring Analytics, LLC 2023).

⇒ To reduce sham scheduling, a validation method for submitted transactions that prohibits breaking transactions into smaller segments to conceal the true source or sink alongside after-the-fact market settlement adjustments to identified sham scheduling segments could be implemented (Monitoring Analytics, LLC 2023).

⇒ Transactions sourcing in the Western Interconnection could be priced at either the MISO or SOUTH interface pricing points based on the locational price impact of the DC tie line flows on the PJM system, not based on geography. For other interfaces, PJM could monitor and adjust weights applied to interface pricing points to reflect ongoing changes to system conditions and review the mappings of external balancing authorities to interface pricing points to reflect changes to external power source impacts on PJM intertie lines because of system topology changes (Monitoring Analytics, LLC 2023).

⇒ PJM could consider eliminating the IMO interface pricing point and instead assign all transactions sourcing or sinking in IESO to the PJM/MISO interface pricing point (Monitoring Analytics, LLC 2023).

⇒ For interface pricing issues between MISO and PJM, the MISO MMU recommends ending the use of the common interface definition at the MISO/PJM seam (Potomac Economics 2023c).

⇒ To prevent redundant congestion pricing, the MISO MMU suggests the M2M constraints modeled by the RTOs (PJM, SPP, MISO) be included only in the monitoring RTO's interface pricing (Potomac Economics 2023c, 95).

⇒ The MISO MMU suggests removing congestion caused by external constraints from prices at interfaces (Potomac Economics 2023c, 95).

3.3.4 Market Co-Optimization of Merchant Interregional HVDC Line

Interregional transmission projects are often privately funded and use controllable HVDC technology. These privately funded merchant transmission lines have FERC-approved market-based rates or negotiated rates recovered from subscribing customers rather than cost-based rates recovered by public utility ratepayers. FERC requires unused capacity on merchant lines to be made available to third parties and has encouraged—but does not require—unused capacity to be made available to RTO/ISO market operators for integrating into the operator's system and co-optimizing in wholesale markets. Optimizing this interregional transmission capacity could improve the efficiency of intertie transactions and maximize interregional transmission value. However, market optimization of HVDC lines is not common within markets, let alone between markets. CAISO is the only U.S. RTO/ISO that co-optimizes HVDC transmission and generation dispatch in nodal day-ahead and real-time markets (Pfeifenberger, Bai, and Levitt 2023, 132). NYISO is revising energy and capacity market design to implement optimization of these controllable lines,[33] while MISO is planning on developing this capability between 2027 and 2031(MISO 2021, 29).

NTP Study modeling shows investments in HVDC transmission additions outpace investments in AC additions to cost-effectively reach national targets. Market reforms to promote the efficient use of these facilities can ensure the benefits of HVDC transmission can be realized.

OPPORTUNITIES

Controllable HVDC lines could provide valuable interregional transmission capacity to deliver energy, capacity, and environmental benefits. To maximize the use of these facilities:

⇒ Regions could explore market reforms to allow developers of merchant HVDC lines to place operational control of their lines with regional market operators.

⇒ CAISO's subscriber participating transmission owner (SPTO) model, recently approved by FERC, could serve as a useful model. Under the SPTO model, CAISO will be able to use unscheduled merchant transmission capacity for regional and interregional transactions in the day-ahead and real-time regional and interregional markets. CAISO would pay the merchant line owner for any nonsubscriber usage of released unscheduled capacity, collected from the transmission access charges allocated to load, imports, and exports (CAISO 2023b). See FERC's approving order at 186 FERC ¶ 61,177 in Docket No. ER23-2917-001.

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[33] See NYISO's "Internal Controllable Lines: 2023 Kickoff," February 21, 2023, at https://www.nyiso.com/documents/20142/36339783/ICL_MIWG_022123.pdf/3859d78e-68aa-e5fc-3a7a-fba6f1ed552d (accessed December 28, 2023), and "Internal Controllable Lines: Market Design Concept Proposal," August 4, 2022, at https://www.nyiso.com/documents/20142/32552857/Internal%20Controllable%20Lines_Market%20Design%20Concept%20Proposed_FINAL.pdf/a36c7967-9959-777a-879e-370fc30c4318 (accessed December 28, 2023).

3.3.5 RTO-Specific Issues

Some RTOs/ISOs have implemented specific technologies, practices, and operating rules that limit the efficient use of transmission. This section summarizes these RTO-specific issues.

Nonoptimized Phase Angle Regulators

Phase angle regulators (PARs) can be used to adjust the phase angle difference between two parallel connected electricity transmission systems. This can control the amount of power flowing across these parallel paths, which can help manage congestion. PJM and NYISO have installed PARs on some of their interconnected lines to improve power flows and price signals between their systems.[34] In the day-ahead time frame, PARs have improved operational efficiency, resulting in $111 million in system savings in 2022 (Potomac Economics 2023a). However, operational improvements in real time have been limited because of a lack of coordination between real-time dispatch from the system operator and the PAR adjustments. The lack of information on expected PAR adjustments can lead to situations where real-time commitments are adjusted to solve congestion issues that were going to be resolved through PAR adjustments at real-time dispatch. Poor PAR coordination is estimated to cause 15% of the price divergence between real-time commitment and dispatch prices (Potomac Economics 2023a).

OPPORTUNITIES

Non-optimized real-time PAR coordination could lead to inefficient use of resources to address power flow issues and price divergence. To improve the use of PARs:

⇒ System operators could incorporate forecasts of PAR adjustments and related real-time impacts into real-time dispatch decisions (Potomac Economics 2023a, 73).

Capacity Pay-for-Performance and Coordinated Transaction Scheduling Inefficiencies

In some markets, CTS scheduling procedures and performance incentive schemes limit rather than augment the ability to use interregional transmission to minimize system outages during extreme events. ISO-NE implemented a pay-for-performance (PFP) scheme that financially penalizes capacity resources for nonperformance in scarcity situations and distributes PFP revenues to capacity resources that do perform. The PFP rules provide $3,500 per MWh to importers that can bring power into ISO-NE during shortages but do not penalize exporters that move power out of the ISO during these times (Potomac Economics 2023b, 46).

During Winter Storm Elliot on December 23–27, 2022, ISO-NE, PJM, and NYISO experienced shortage hours. During these hours, while ISO-NE was importing power to avoid power outages, some generators within ISO-NE were taking advantage of high prices in NYISO (because of shortages in that system) and exporting power to New York (Potomac Economics 2023b, 45).

[34] We note operation of some of these PARs have been subject to controversy, including but not limited to RTO/ISO control of PARs (Opinion No. 476, Docket EL-02-23, August 2, 2004), negotiation between entities on terms and conditions to operate and recover costs for these PARs (ER08-1281; ER11-1844), related interface pricing reforms (e.g., ER08-1281, Order on December 30, 2010), and other issues.

Inefficient market signals existed that simultaneously allowed for profitable imports into ISO-NE and exports out of ISO-NE (i.e., to NYISO). These inefficient market signals relate to ISO-NE's PFP rules (discussed previously) and, to a lesser degree, CTS scheduling limitations. The CTS process requires bids be locked in 75 minutes before the delivery hour. These rules prevented any adjustments to interchange schedules for the first hour of shortage in ISO-NE. The combination of conflicting economic incentives and limited ability to adjust interchange schedule led to an inefficient use of resources within ISO-NE that was costly for consumers who faced power outages and high prices.

OPPORTUNITIES

Poorly designed performance incentives and scheduling rules may limit the ability to use interregional transmission to minimize system outages during extreme events. To improve the ability to respond during emergencies:

- ⇒ Reforms to exporter charges could be considered, such as charging exporters the PFP rate during scarcity conditions, to deter exports that may exacerbate outages (Potomac Economics 2023b).
- ⇒ PFP compensation rates could be dynamic with a lower rate consistent with the value of lost load during normal conditions that is escalated as the probability of load shedding increases (Potomac Economics 2023b).

Capacity Import Limits

Interregional transmission can reduce the cost of meeting resource adequacy requirements by enabling greater use of the lowest-cost resources to meet these requirements across a broader geographic area. In practice, the resource adequacy value of interregional transmission has been limited by concerns that external resources may not be able to deliver capacity when needed.

For example, in 2014, PJM introduced a capacity import limit (CIL) that restricts the amount of external generation capacity eligible to serve as a capacity resource within PJM.[35] PJM proposed these limits after observing an 80% increase in external capacity offering into its base residual auction (BRA) citing 4,649 MW offered in the 2015/2016 BRA and 8,412 MW offered in the 2016/2017 BRA.[36] PJM was concerned neighboring systems could impact the deliverability of energy through congestion management actions and curtailment during TLR events. PJM also expressed concern external capacity could artificially lower capacity prices (e.g., by not reflecting the true cost of delivery into PJM), cause other generators to retire, and undermine reliability if they cannot deliver when needed.

[35] See FERC Dockets ER14-503-000 and ER14-503-001, with Order Accepting Tariff Revisions issued April 22, 2014.
[36] Ibid.

Through a series of reforms to PJM's capacity market rules, PJM was permitted to downwardly adjust the CIL and impose new criteria for external resources.[37] Under these new pseudo-tie criteria, external capacity resources must meet requirements for minimum electrical distance, flowgate eligibility, transaction eligibility, validation of network models, confirmation of transmission service agreements, and offered capacity. In the 2024/2025 BRA, only 1,527 MW of external capacity was offered and 1,398 MW cleared (PJM Interconnection 2023b).

In addition to deliverability concerns, there may be other factors such as in-state installed capacity requirements in renewable energy portfolio standard policies that prompt states to take a more restrictive approach to capacity imports. On the other hand, some states may have greater appetite for external resources, for example, if weather and production patterns in host areas are well matched with load patterns in the destination area.

OPPORTUNITIES

Explicit restrictions on the use of external capacity for resource adequacy may limit otherwise efficient resource sharing. To address concerns about deliverability and maximize the efficient use of resources to meet resource adequacy needs:

- ⇒ Concerns about TLR-related deliverability issues could be addressed through intertie optimization or joint operating agreements with neighboring areas to more effectively manage congestion.
- ⇒ FERC/NERC could supplement existing operating reserve sharing groups with guidelines or best practices to facilitate resource adequacy sharing in the planning horizon.

[37] See FERC Order on Tariff Revision (November 17, 2017) Dockets ER17-1138-000 and ER17-1138-001 available at https://www.pjm.com/directory/etariff/FercOrders/2324/20171117-er17-1138-000,%20001.pdf (accessed August 29, 2023)

4 Transformative Opportunities

Compared to the opportunities identified in Section 3, the following options represent actions that require greater effort to design and implement but also offer greater potential economic, reliability, and resiliency benefits by transforming the way interregional transmission assets are operated. This section presents ambitious, national actions that could unlock the value of interregional transfer capacity to consumers across both market and nonmarket areas.

4.1 Systemwide Transformation

4.1.1 Long-Range, Nationwide Interregional Transmission Planning

Several entities have advocated the need for ongoing nationwide, long-range transmission planning to improve interregional connectivity that could in turn benefit renewable energy integration, reliability, and resilience (Energy Systems Integration Group 2021; Americans for a Clean Energy Grid 2021; Reed 2021). The details of how such a plan would be conducted are beyond the scope of this report. However, the general notion is there is a need for a broader perspective on transmission, one that goes beyond FERC Order No. 1000's interregional transmission coordination or regional and local transmission planning. The specific goal of a national transmission plan would be to determine if there are cross-border transmission projects that could deliver benefits well in excess of their costs while helping achieve market and/or policy goals. Such a plan could be developed by a stand-alone entity or through a collaboration of transmission planning regions. The appropriate entity should be able to conduct detailed engineering and modeling studies including reliability analysis, and incorporate local and regional plans, capacity expansion data, and other inputs and analysis. The NTP Study approach provides one example of national grid-scale analysis that could inform regional and local analysis and planning efforts. The European Network of Transmission System Operators for Electricity's (ENTSO-E's) 10-year network development plan provides an alternative bottom-up approach for multijurisdictional planning that takes in inputs from individual transmission system operators to create an EU-wide network plan.

European Network of Transmission System Operators for Electricity's (ENTSO-E) Network Planning

ENTSO-E is an association representing 39 independent transmission system operators from 35 European countries. ENTSO-E was legally established by the Third Energy Package to increase transparency, improve cooperation, and enhance cross-border trading to facilitate the EU's vision of a single internal electricity market.

Among other things, ENTSO-E biannually develops a nonbinding, European-wide, 10-year network development plan (TYNDP). This TYNDP links national transmission plans and develops a European-wide vision of the future power system. Specifically, it explores how interregional transmission and energy storage projects can be used to reduce the cost of energy transition while maintaining reliable and safe operations. These activities support the EU's goals of achieving carbon neutrality by 2050.

The 2022 TYNDP began with identifying a variety of future scenarios of how the power system could evolve in the future over two horizons, 2030 and 2040. These scenarios were informed in part by EU and member state data sources and stakeholders and in conjunction with natural gas system operators. Next, analysis was conducted to identify system needs and opportunities for cross-border infrastructure and noninfrastructure (e.g., dynamic line ratings) solutions to improve the efficiency of the system while reaching decarbonization targets. The TYNDP also performed cost-benefit analysis on the individual projects considered in the study. For the 2022 TYNDP, this includes 141 transmission projects and 23 storage projects.

The TYNDP process is overseen by the Agency for the Cooperation of Energy Regulators and adopted by the European Commission. The plan develops the starting point for identifying transmission projects of common interests that are eligible for special regulatory treatment and incentives. The 2022 TYNDP identified 64 GW of cross-border transmission capacity over 50 borders between 2025 and 2030 and another 88 GW of cross-border capacity by 2040.

More information about the ENTSO-E TYNDP can be found at https://tyndp.entsoe.eu/.

4.1.2 Intertie Optimization

RTOs/ISOs can optimize the transmission system and generation fleet within their territories, but inefficiencies remain when trading between markets. Optimizing interchange transactions could occur in a variety of forms, with increased potential benefits as geographic scales expand—for example, intertie optimization between market and nonmarket areas to improve the efficiency of interchange transactions or replace the JOA processes (e.g., CTS) with intertie optimization between market areas. A more ambitious option would be interconnection-wide intertie optimization.

Intertie optimization has been advocated for by some RTOs/ISOs as a solution to uncoordinated interchange since at least 2011 (ISO New England and NYISO 2011). Intertie optimization means the ISOs manage transmission ties between them in the same manner that the ISOs manage internal transmission, using bid-based security-constrained economic dispatch. In 2014, the PJM MMU recommended the following:

> " …PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market." (Monitoring Analytics, LLC 2023, 61)

On the other hand, some have expressed concerns that RTO/ISO intertie optimization would reduce market arbitrage opportunities for traders or undermine the financial neutrality of the RTO through determination of an optimal joint dispatch solution (Guo, Ji, and Tong 2018).

Interconnection-wide intertie optimization could take many forms. For example, existing market and/or BAA software could share information with a central system that would dispatch interties based on available transfer capacity. Optimization could be limited to spare capacity after accounting for interchange based on bilateral contracts and wheeling that have secure physical transmission rights. Costly construction of a network model along market seams would be required but could enable the coordination of security constraints rather than the current practice of estimating these constraints. This would allow different states and RTOs/ISOs to maintain decision-making authority about resource scheduling while improving the efficiency of real-time interregional trading. The European Union's market coupling initiatives are another model of intertie optimization, in this case across multiple countries.[38]

[38] Intertie optimization is discussed more fully in the recent report from Pfeifenberger and Bay, *The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encourage Interregional Transmission*, October 2023, located at 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 (accessed March 20, 2024).

The European Union’s Market Coupling Initiative

Since as early as 1988, the European Union has considered how to achieve a single internal energy market, including an integrated electricity market among member states. Some policy efforts to support the single internal market include the 15% cross-border transfer capacity mandate by 2030, regulations to facilitate cross-border “projects of common interest” (PCI) infrastructure, and funding for PCI development. Market coupling seeks to form an interconnected European market for electricity to efficiently allocate resources and lower prices.

Some early issues in the EU that led to the inefficient use of cross-border transmission capacity included restricted access to congested transmission links and incumbents withholding historic access rights with the aim of limiting cross-border trading (leading to low or uneconomic cross-border power flows) (Pollitt 2019). These and other issues led to the European Commission’s Energy Inquiry published in 2007 (Commission of the European Communities 2007). The inquiry found access to cross-border transmission was being blocked by incumbent long-term contracts and capacity withholding; stronger regulatory oversight was needed over cross-border issues; greater harmonization of market design was needed, especially related to cross-border trade; and changes were needed regarding the method of allocating scarce intertie capacity and incentives to maximize the amount of cross-border capacity available to the market.

The Capacity Allocation and Congestion Management (CACM) regulations established the EU-wide single market coupling rules for the single day-ahead coupling and single intraday coupling markets. The CACM rules apply to transmission system operators (TSOs), regulatory authorities, and nominated electricity market operators (NEMOs). Allocation of cross-zonal capacity through market coupling involves the following:

- Each member state designating a NEMO to perform single day-ahead and intraday coupling
- Establishing a market coupling operation (MCO) plan for the NEMO to implement
- Developing coupling algorithms that are scalable, repeatable, and seek to maximize economic surplus
- Offering coupling products, harmonizing minimum and maximum clearing prices and automatic adjustment mechanisms to revise prices
- Finalizing backup procedures established by the NEMOs and TSOs for market operations if there are no market coupling results available.

In addition to these rules, there are coupling regulations governing capacity calculations between zones, management of residual congestion, and periodic reviews of bidding zones.

A study conducted by the European NEMOs estimated the benefits of 2021 actual cross-border trade (compared to a theoretical zero-trade model) to be 34 billion euros while reducing price volatility (European Union Agency for the Cooperation of Energy Regulators 2022). The benefits of market coupling related to the efficient use of cross-border interconnections was estimated to be 1 billion euros per year (European Union Agency for the Cooperation of Energy Regulators 2022).

4.1.3 Nationally Coordinated System Planning and Operations

Establishing an entity that could coordinate nationwide system planning and operations is an ambitious concept with the potential to increase system efficiencies and benefits. This concept would also involve considerable technical, legal, and other important complexities. In theory, this entity could have the following functions:

- National generation and transmission planning with an emphasis on interregional transmission and intertie capacity requirements for resource adequacy and resiliency
- Day-ahead scheduling and real-time dispatch
- Development and sharing of resource adequacy resources
- Nationwide market monitoring.

As mentioned previously, although centralizing transmission planning and operations into a single entity would, in theory, maximize the cost and reliability benefits of interregional transmission, this is also the most technically and politically difficult concept to implement. Many important and unanswered questions exist. First, it is unclear how this entity would be established and whether there is interest among relevant national authorities to initiate such an organization. A second significant challenge is related to the scope of this entity's authority and how decision-making authority would be shared with states and existing markets. Regional and local entities may be reluctant to cede decision-making authority to a national entity. Many regions have made significant gains reaching a regional consensus on issues such as how to accommodate state energy policies, provisions for public power, and different approaches to resources adequacy through agreements such as open access transmission tariffs. Under a national entity, these agreements could either be replaced by national rules, potentially leading to litigation, or be retained—resulting in a variety of solutions that may exacerbate coordination issues across regional seams. Independent from legal constructs, computationally, more work is needed to develop methods capable of yielding market clearing solutions to coordinate system operations on a national scale. Finally, experimentation among individual regions has led to innovative solutions in market design and system planning. Under a national entity with a broader set of interests and stakeholders, the planning and decision-making process may become more cumbersome, slowing rather than streamlining the pace of change.

Several design options exist to achieve the benefits of a national system planner and operator while minimizing the implementation challenges and concerns around local and regional authority for decision making. For example, existing bilateral markets and RTOs/ISOs could remain in place while layering the national entity over these constructs. In practice, this would function more like multi-RTO coordination, for example, combining aspects of both nationwide transmission planning and intertie optimization. The national entity could focus solely on scheduling and dispatching available resources after BAAs and RTOs/ISOs develop their base schedules. This design avoids the need to harmonize market rules and structures across the different balancing authorities but could also lead to inefficiencies because of underparticipation compared to mandatory national scheduling and dispatch of all resources. Inefficiencies in managing congestion could also arise if zonal aggregation is used to simplify the representation of electrical networks and facilitate trade (Aravena et al. 2021). To coordinate system planning, the national entity could facilitate cross-border capacity procurement on behalf of interested states, markets, or BAAs. The national entity's transmission planning activities could be limited to interregional transmission planning. This planning could include intraregional lines that are needed to facilitate anticipated increases in interregional power flows between and across regions. Therefore, some process will be needed to define the interregional network and distinguish between intra- and interregional lines that should be included in this process. Market monitoring functions could guard against market manipulation across all markets. To minimize conflicts, the establishment of this national system planner and operator could define the responsibility and authority of regional institutions to coordinate with the national entity for market monitoring functions.

Though this national construct is ambitious, it is not unprecedented. In fact, the EU's market coupling effort provides an example of how multiple nations collaborated to develop a single market for EU-wide real-time dispatch optimization and cross-border trading.[39] In Great Britain, the Office of Gas and Electricity Markets (Ofgem) is developing a new entity, called the Future System Operator, to plan and operate the national power and gas systems.[40]

[39] The EU's market coupling initiative provides an example of a program that could be implemented by a cross-border, national system operator. However, the EU's market coupling program is based on zonal electricity markets, which after clearing require significant and costly congestion management actions in real time to avoid overloading transmission lines. A nodal-based market coupling system has been proposed to improve the efficiency and real-time performance of the market coupling initiative (Aravena et al. 2021).

[40] More information about Ofgem's Future System Operator can be found at https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/future-system-operation-fso, accessed February 19, 2024, and the UK government's website at https://www.gov.uk/government/publications/energy-security-bill-factsheets/energy-security-bill-factsheet-future-system-operator, accessed February 19, 2024.

5 Conclusion

As the United States seeks to transform its electricity supply with increased shares of clean energy, the electricity grid will need to transform in parallel to accommodate new sources of supply with new output profiles developed across the country. The NTP Study finds interregional transmission can be a key enabler to achieve a low-emissions grid that can maintain reliability at least cost. Efficient use of existing interregional transmission and increased development of new interregional transmission can reduce the costs of meeting system needs for both energy and reliability. Expanding and efficiently operating transmission intertie capabilities expands the geographic reach of interconnected system, with benefits including improved resilience to unpredictable events (e.g. extreme weather, unplanned outages) and greater resource sharing potential to balance system needs.

This report identifies several barriers that exist within current rules and operating practices that may prevent the full suite of transmission benefits from being realized. Most of these barriers reduce the efficiency of intertie operations whereas some barriers directly limit the services interties can provide. This report outlines potential opportunities, summarized in Figure 9, tailored to trading in market or nonmarket regions to improve the operations and planning of interregional transmission.

Not fully explored in this report are the technical complexities associated with these barriers and the potentially contentious stakeholder dynamics that may be encountered when grid operators attempt to pursue solution options.

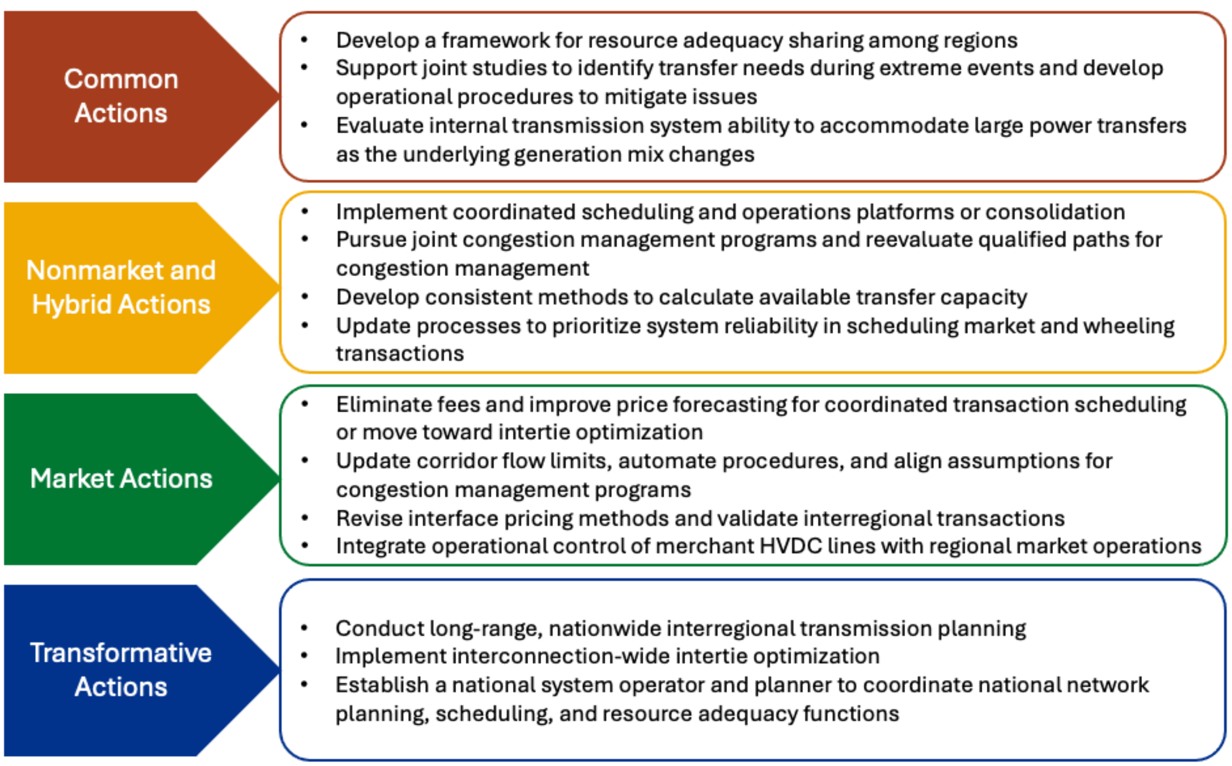

Figure 9. Summary of incremental and transformative opportunities to realize the system value of interregional transmission

Incremental options to improve market-to-market trading focus on addressing shortcomings in joint operating agreements and improving the system value of available merchant line capacity. Options to improve trading in nonmarket areas focus on increasing levels of coordination and resource sharing. To fully capture the value of interregional transmission capability, more ambitious, transformative actions could be pursued. These include greater intertie or interconnection-wide optimization and considering the benefits of nationwide coordination of system operations and planning. The barriers and opportunities identified in this report can guide a suite of potential reforms to increase systemwide benefits.

In the analysis of barriers and potential opportunities for improvement, we recognize these are complex issues with a diverse set of power system stakeholders and factors that must be considered. The goal of this report is not to make recommendations but to identify options to improve the use of interregional transmission that could be considered alongside other local, state, and regional objectives.

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