# Optimal Expansion and Use of Interregional Transfer Capability


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PREPARED FOR

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Brattle

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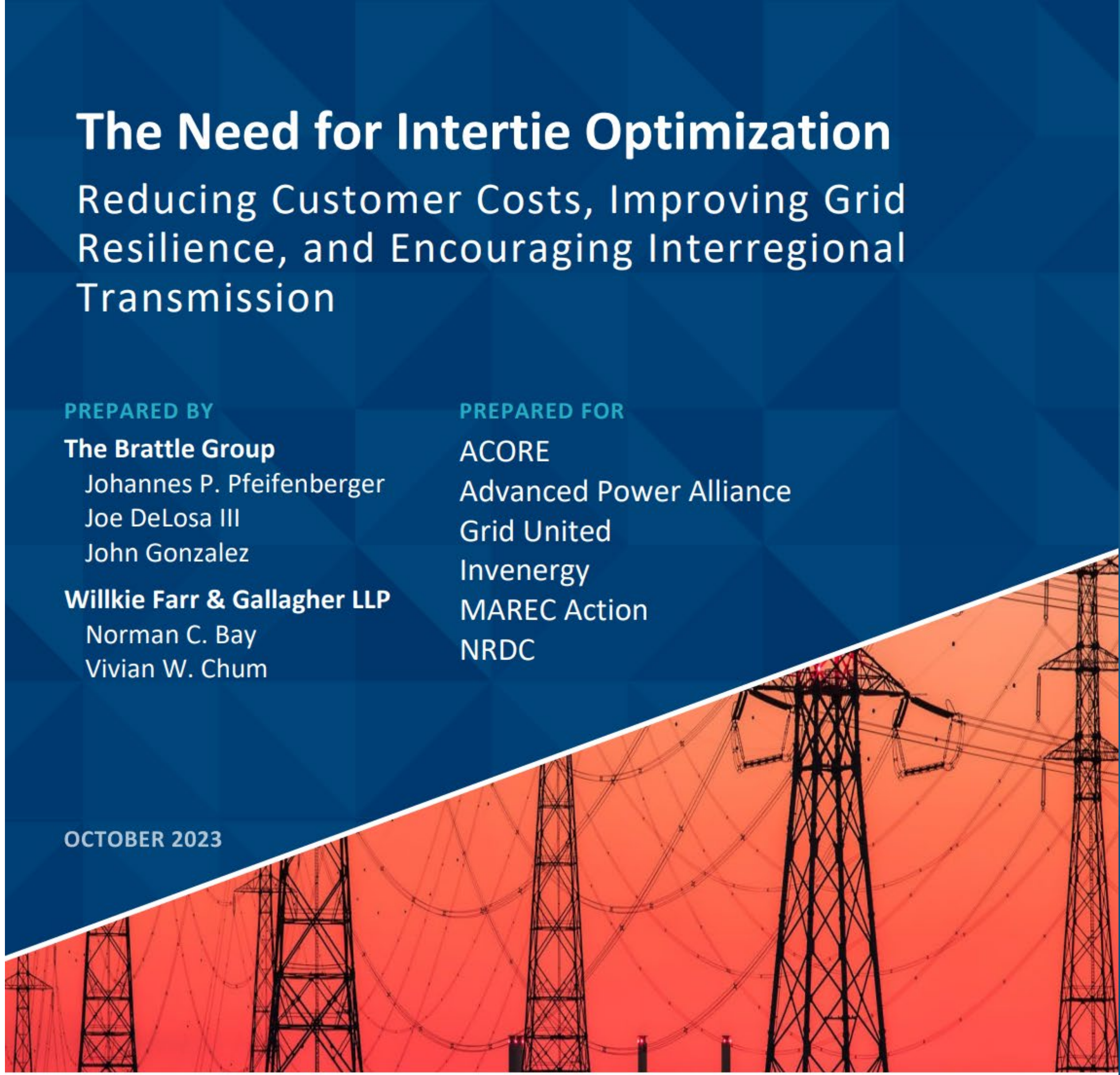


This presentation is based in part on the report, The Need for Intertie Optimization, prepared with colleagues at The Brattle Group and Willkie Farr & Gallagher with input from industry participants. ACORE, Advanced Power Alliance, Grid United, Invenergy, MAREC, and NRDC commissioned the report.

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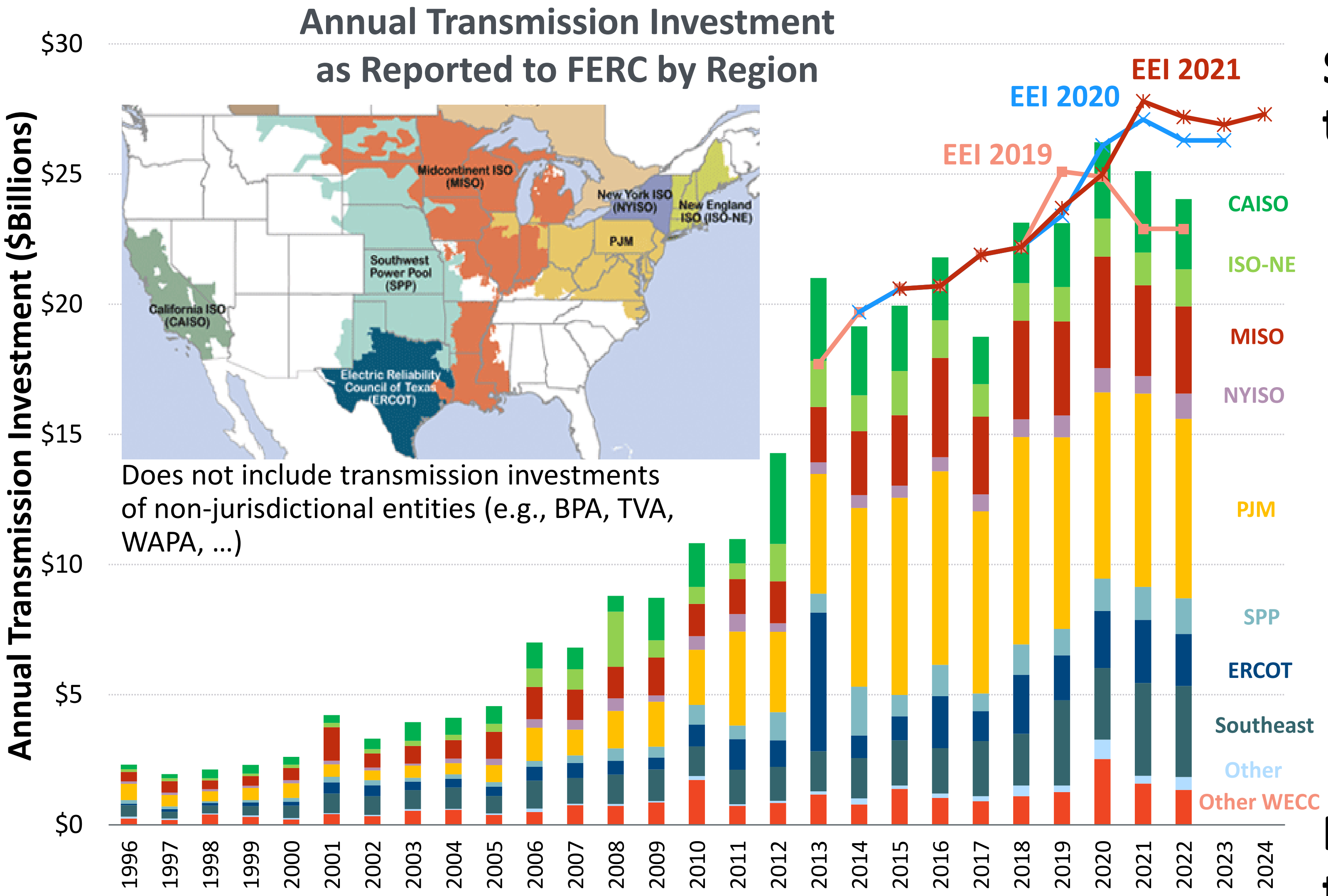
# The Five Sources of Inefficiencies Created by RTO Seams

**Seams between RTOs will generally be more efficient than seams between non-market regions that rely entirely on bilateral trades. Nevertheless, significant seams-related inefficiencies exist between RTO markets:**

1. **Interregional transmission planning** (as discussed next in this presentation)
2. **Generator interconnection** delays and cost uncertainty created by affected system impact studies (and effectiveness coordination through means such as the SPP-MISO JTIQ, reducing costs by 50%)
3. **Resource adequacy** value of interties (often not considered in RTO's resource adequacy evaluations) and barriers to capacity trades (often created by RTOs' restrictive capacity import requirements and incompatible resource accreditations)
4. **Loop flow management** through market-to-market coordinated flowgates (with shares of firm flow entitlements) under the existing JOAs
5. **Inefficient trading** across contract-path market seams and the need for intertie optimization (as discussed later in this presentation)

# Transmission Investment is at Historically High Levels



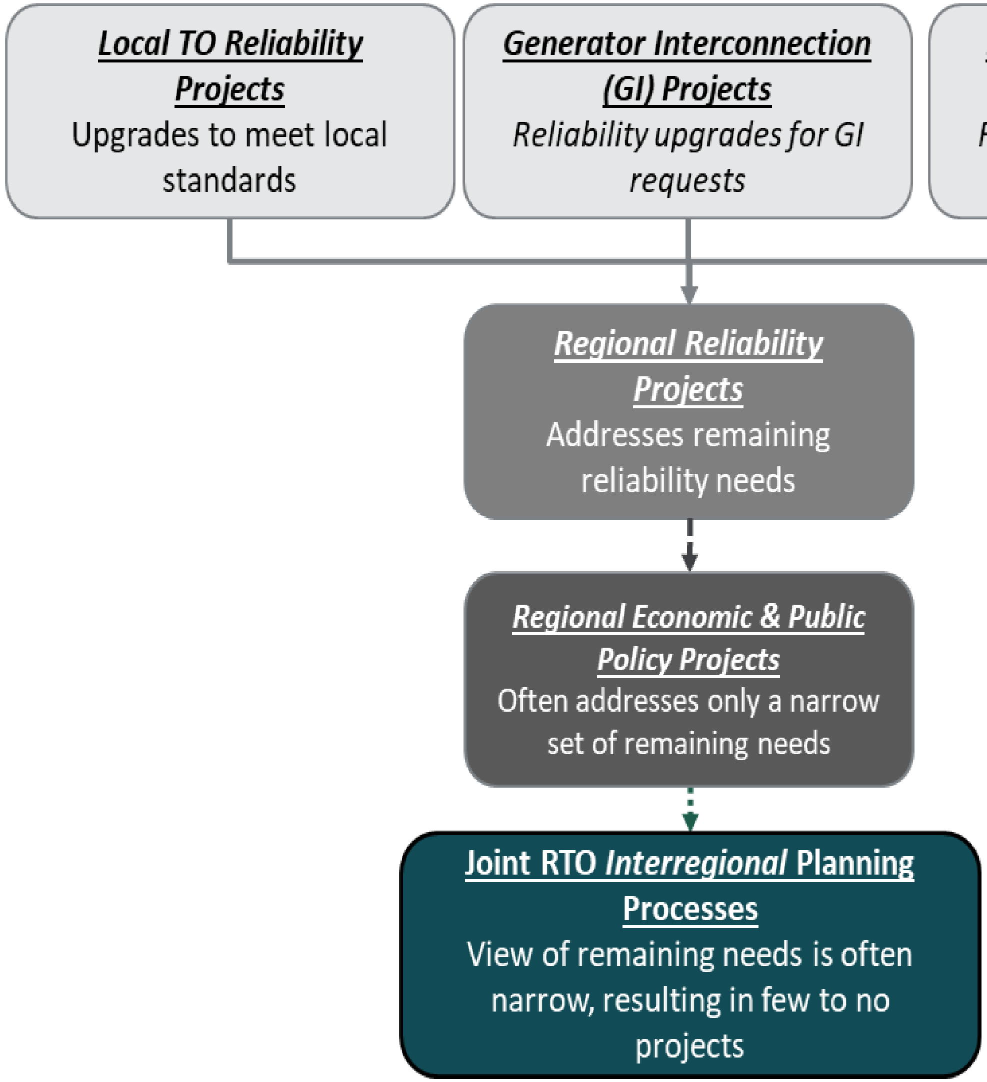

Sources: The Brattle Group analysis of FERC Form 1 Data; EEI "Historical and Projected Transmission Investment" most recent accessed here: https://www.eei.org/resourcesandmedia/Documents/Historical%20and%20Projected%20Transmission%20Investment.pdf

**$20-25 billion in annual U.S. transmission investment, but:**

- More than 90% of it justified solely based on reliability needs without benefit-cost analysis
  - About 50% solely based on “local” utility criteria (without going through regional planning processes)
  - The rest justified by regional reliability and generation interconnection needs
- While significant experience with transmission benefit-cost analyses exists, very few projects are justified based on economics to yield overall cost savings

**Essentially no interregional transmission!**

# Current U.S. Grid Planning Processes are too Siloed




**These solely reliability-driven processes account for > 90% of all transmission investments**

- None involve any assessments of economic benefits (i.e., cost savings offered by the new transmission)
- Which also means these investments are not made with the objective to find the most cost-effective solutions
- Will yield higher system-wide costs and electricity rates

**Planning for economic and public-policy projects: less than 10% of all transmission investments**

**Interregional planning processes are largely ineffective**

- Essentially no major interregional transmission projects have been planned by grid operators in the last decade
- Regional focus on meeting reliability needs leaves no “need” for interregional transmission, even if more cost effective

# Barriers to Interregional Transmission Planning

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

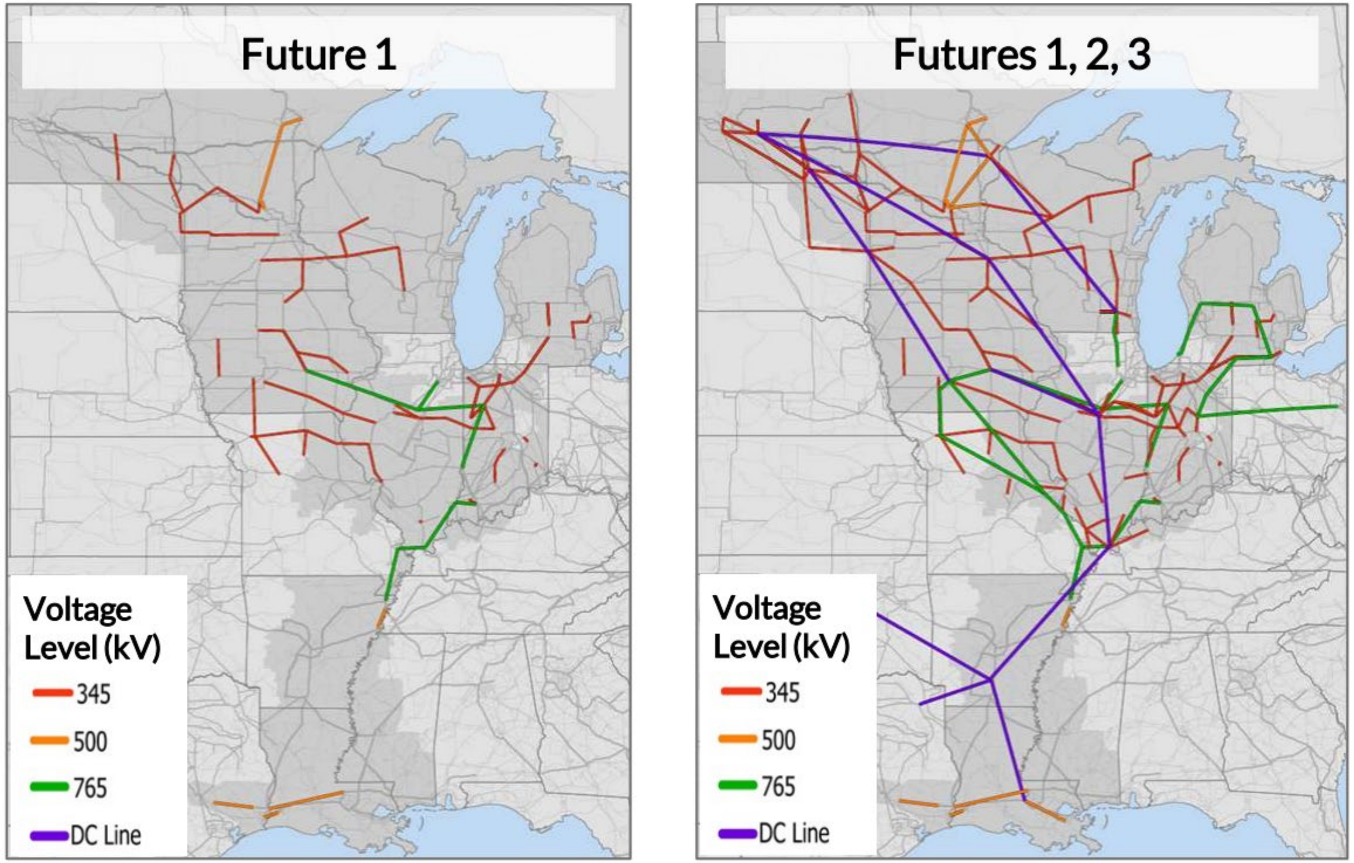
*Source*: Appendix A of A Roadmap to Improved Interregional Transmission Planning, November 30, 2021. Based on interviews with 18 organizations representing state and federal policy makers, state and federal regulators, transmission planners, transmission developers, industry groups, environmental groups, and large customers.

# Example: Prioritizing Regional over Interregional Solutions

- MISO's new Renewable Integration Impact Assessment (RIIA) improves on many other planning studies by:
  - Establishing the need to study both <u>policy</u> goals and <u>reliability</u> goals simultaneously
  - Considering diverse future <u>scenarios</u>
  - Recommends a "least-regret" transmission plan (but one that does not address possibility of regret from inadequate T)
- By design, **the scope of study does not address any interregional opportunities:**
  - Despite modeling five regions in addition to MISO, the study mostly did not consider interregional transmission (see figures)
  - Even if "optimal" for MISO, it likely preempts more cost-effective interregional solutions

**How would SPP-MISO-PJM wide planning results differ?**

**MISO's projected scope of transmission expansion needs**




Source: [MISO LRTP Roadmap March 2021](MISO LRTP Roadmap March 2021)

# Understanding Transmission-Related Benefits

**Wide-spread nature of benefits creates challenges in estimating them and how they accrue to different users, which also complicates cost allocation**

| | |
|---|---|
| **Broad in scope, providing many <u>different types</u> of benefits** | • Increased reliability and operational flexibility<br>• Reduced congestion, dispatch costs, and losses<br>• Lower capacity needs and generation costs<br>• Increased competition and market liquidity<br>• Renewables integration and environmental benefits<br>• Insurance and risk mitigation benefits<br>• Diversification benefits (e.g., reduced uncertainty and variability)<br>• Economic development from G&T investments |
| **<u>Wide-spread</u> geographically** | • Multiple transmissions service areas<br>• **<u>Multiple states</u>** and regions |
| **<u>Diverse</u> in their effects on market participants** | • **<u>Customers</u>, <u>generators</u>, <u>transmission owners</u>** in regulated and/or deregulated markets<br>• Individual market participants may capture one set of benefits but not others |
| **Occur and <u>change</u> over long periods of time** | • Several decades (50+ years), typically increasing over time<br>• Changing with system conditions and future generation and transmission additions<br>• Individual market participants may capture different types of benefits at different times |

**Economic benefit of transmission =**

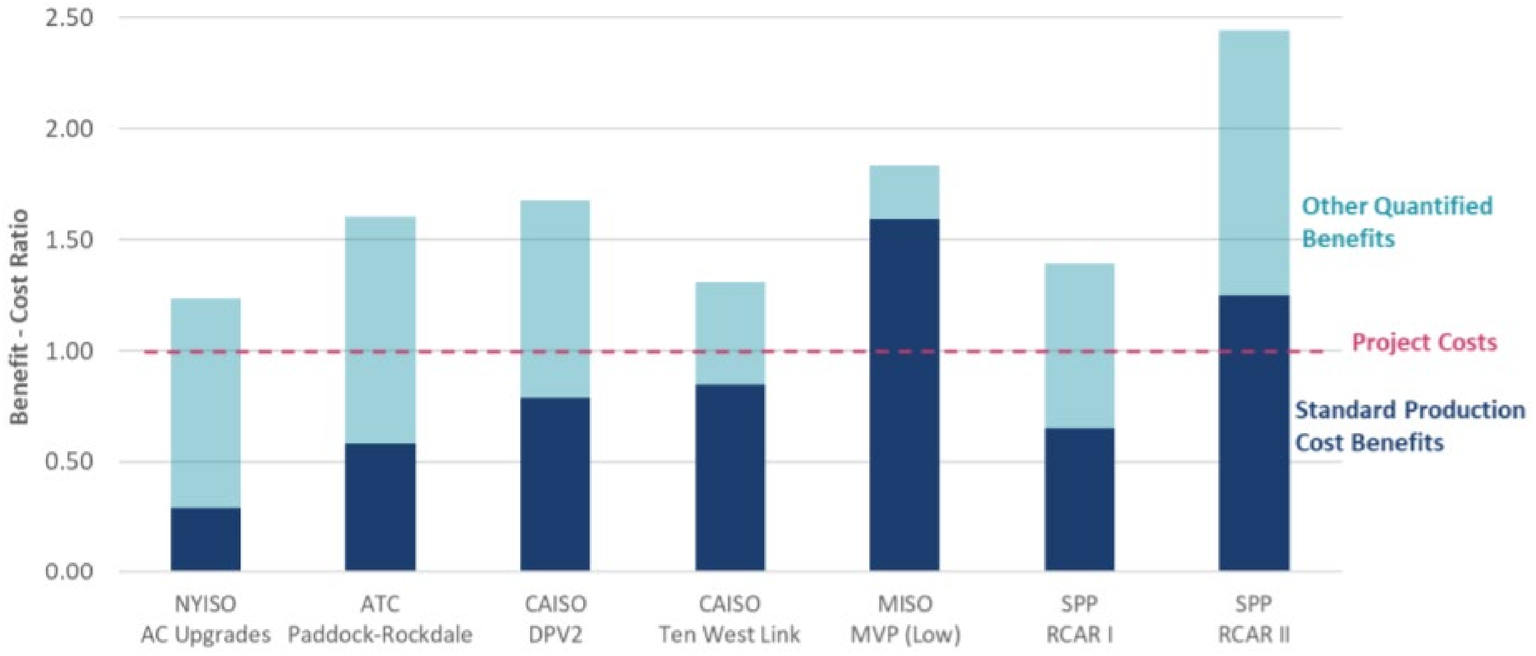
**+ Cost savings that reduce overall system-wide costs faced by customers**

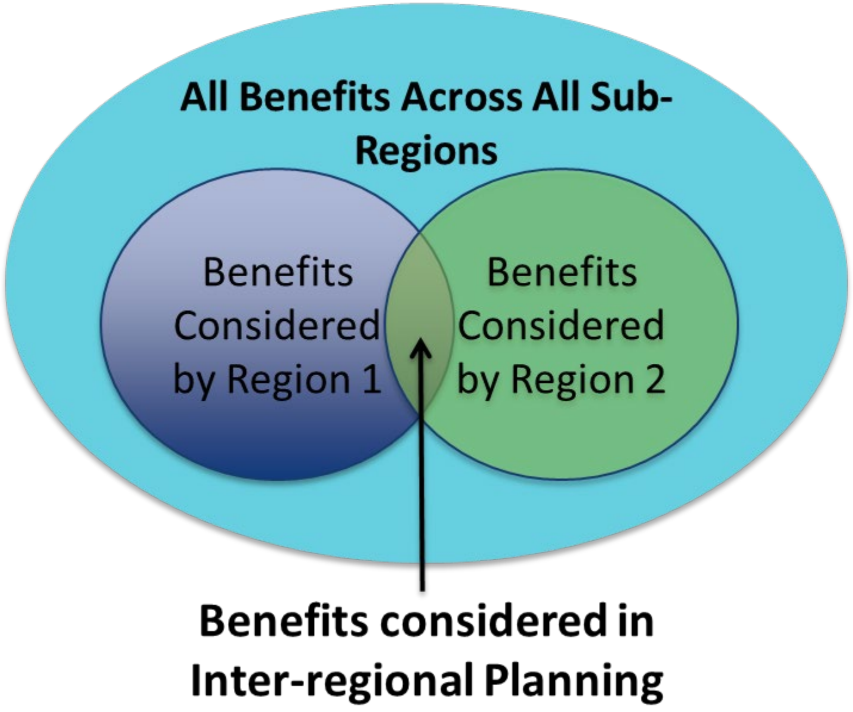
**+ Economic value of added reliability**

# Quantifying Benefits Beyond “Production Cost” Savings

**Relying solely on traditionally-quantified <u>Adjusted Production Cost</u> (APC) Savings results in the rejection of beneficial transmission projects – particularly for interregional planning efforts that consider an even smaller subset of benefits**

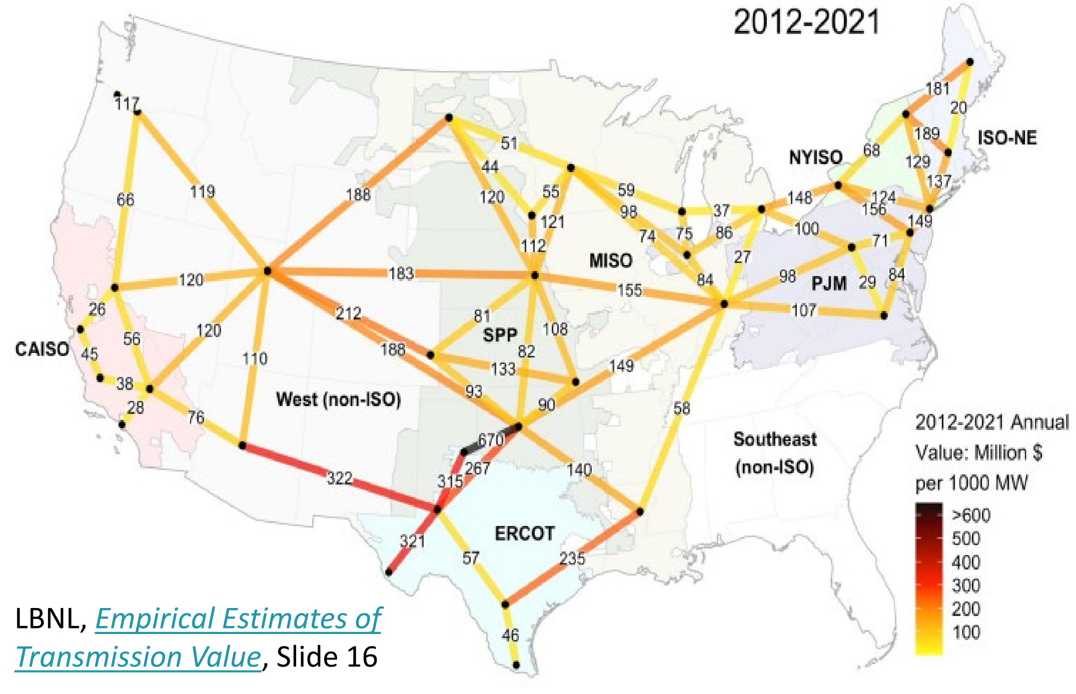
FIGURE 5. BENEFIT-COST RATIOS OF TRANSMISSION PROJECTS WITH AND WITHOUT A BROAD SCOPE OF BENEFITS



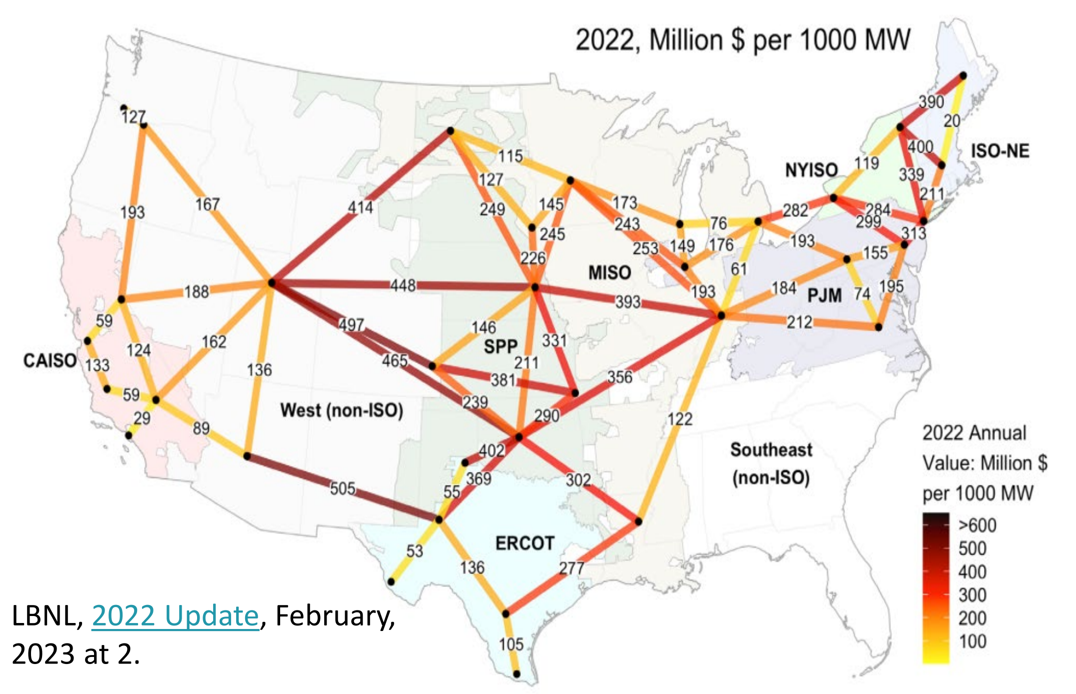




Source: [Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs]
[A Roadmap to Improved Interregional Transmission Planning].

# LBNL Empirical Estimates of the Value of Interregional Transmission




LBNL, [Empirical Estimates of Transmission Value](), Slide 16




LBNL, [2022 Update](), February, 2023 at 2.

*Sources: [LBNL, Empirical Estimates of Tx. Value]() (Aug 2022), Slide 16; [The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade](), Fact Sheet, LBNL (Feb 2023) at 2.*

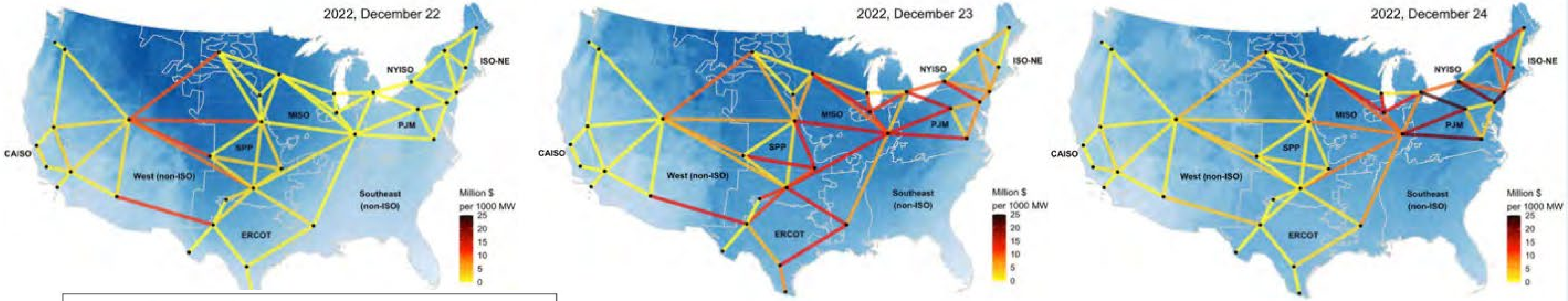
**Methodology:** Transmission value based on historical real-time price difference between regional nodes

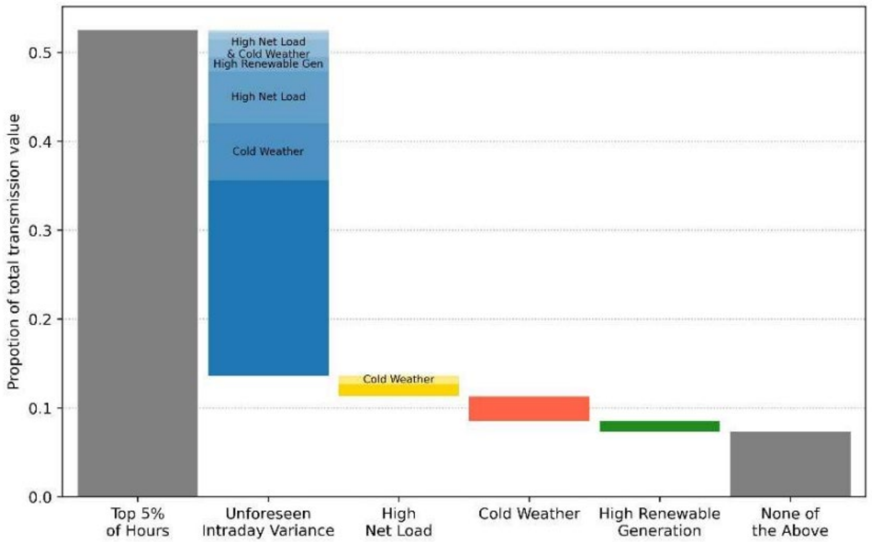
**Study Findings:**

- Interregional links have greater value than regional links
- **40-80% of transmission's congestion value is from 5% of hours due to extreme conditions,** <u>20-30% from top 1% of hours </u>reflecting the high impact of challenging system conditions
- The value in some of the recent years (e.g., 2021, 2022) is double the 10-year average

# Value of Transmission is Concentrated in Few Unpredictable Hours

Highest transmission congestion is concentrated in relatively few hours of the year and during extreme events. Example: Winterstorm Elliot (2022)




**Findings:**

- Real-time values (reflecting actual conditions) are higher than DA values
- On average, about half of the value is concentrated in top 5% of all hours
- Most of that value is due to real-time market conditions that are not foreseeable on a day-ahead basis
- Estimated benefits exceed estimated costs for all interregional projects

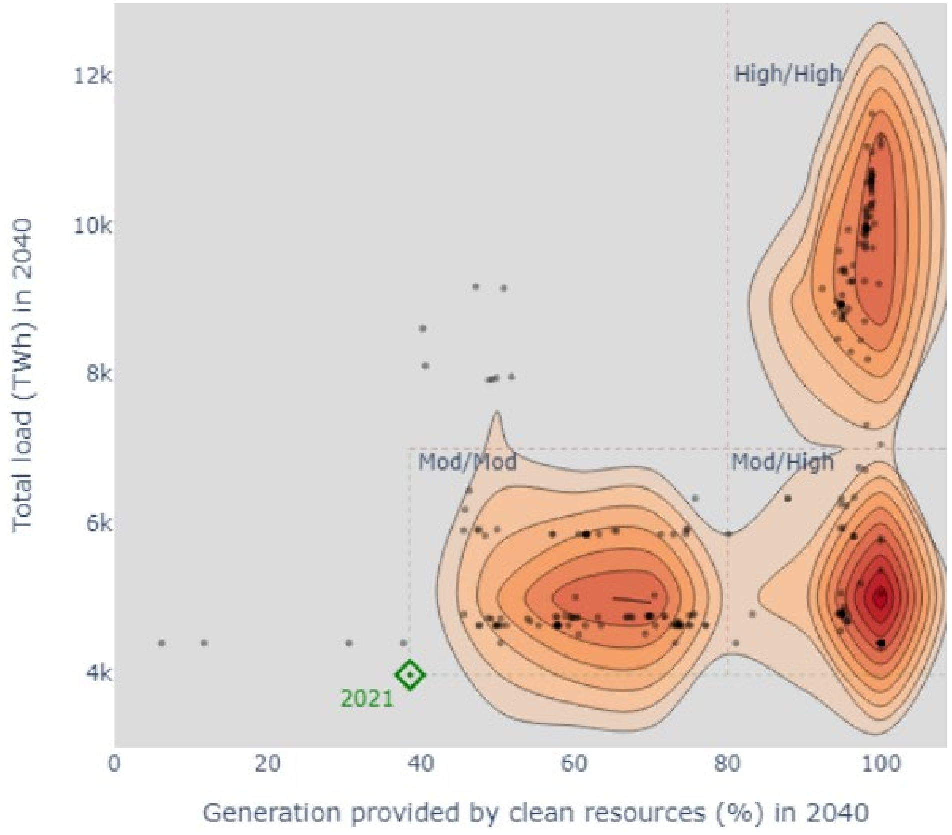
*Sources:* LBNL, Transmission Value Manuscript NatureEnergy (March 29, 2024); Department of Energy's 2023 National Transmission Needs Study (Oct 2023)

# DOE's 2023 Transmission Needs Study: Review of National Analyses

DOE's National Transmission Needs Study documented high historical value of interregional transmission and summarized numerous results from six national studies into 3 groups of scenarios:

1. **Mod/Mod** = status-quo: moderate load growth and 40-70% clean-energy shares
2. **Mod/High** = moderate load growth but high (90+%) clean-energy shares
3. **High/High** = high electrification load growth and high clean-energy shares

**"Need"** = optimal regional/interregional transmission expansion that minimizes total system-wide costs
("Expansion" = enhancing the existing grid & existing ROW plus new transmission lines)



# DOE's 2023 Transmission Needs Study: Interregional Needs

**Example: Cost-effective interregional transmission capacity between Northern WECC, SPP, MISO-N, and PJM:**

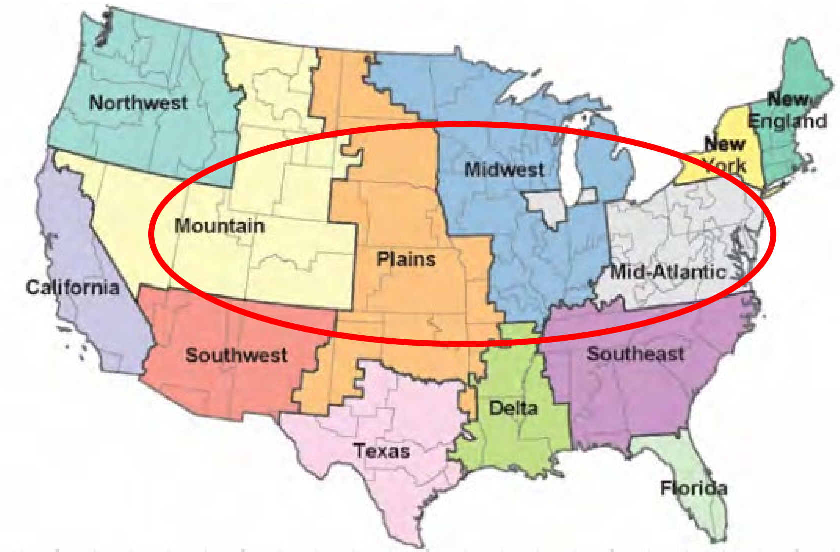


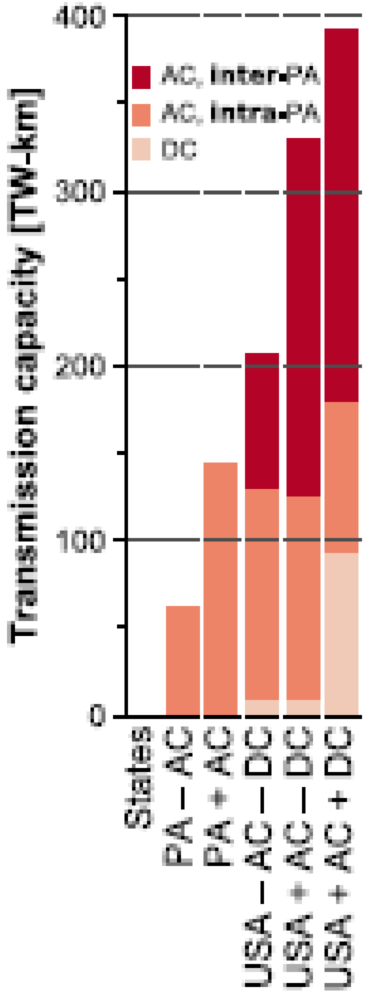

***Table VI-4. Median regional transfer capacity results for each scenario group in 2030, 2035, and 2040. Both new transfer capacity in GW and percent growth from 2020 system are shown.***

| Regional Pair | 2020 GW | Scenario Group | New in 2030 | | New in 2035 | | New in 2040 | |
|---|---|---|---|---|---|---|---|---|
| | | | GW | % Growth | GW | % Growth | GW | % Growth |
| **Mountain – Plains** | 0.92 | Mod/Mod | 0.36 | 39.1% | 0.94 | 102% | 1.40 | 152% |
| **Mountain – Plains** | 0.92 | Mod/High | 0.79 | 85.4% | 2.64 | 287% | 11.9 | 1,290% |
| **Mountain – Plains** | 0.92 | High/High | 6.10 | 663% | 19.3 | 2100% | 29.2 | 3,170% |
| **Midwest – Plains** | 12.1 | Mod/Mod | 1.35 | 11.2% | 3.14 | 26.0% | 3.62 | 30.1% |
| **Midwest – Plains** | 12.1 | Mod/High | 7.99 | 66.3% | 21.1 | 175% | 23.0 | 191% |
| **Midwest – Plains** | 12.1 | High/High | 24.6 | 204% | 88.0 | 731% | 98.7 | 819% |
| **Mid-Atlantic – Midwest** | 21.7 | Mod/Mod | 1.10 | 5.1% | 2.39 | 11.0% | 2.65 | 12.2% |
| **Mid-Atlantic – Midwest** | 21.7 | Mod/High | 9.87 | 45.5% | 33.8 | 156% | 21.9 | 101% |
| **Mid-Atlantic – Midwest** | 21.7 | High/High | 42.4 | 196% | 103 | 475% | 119 | 550% |

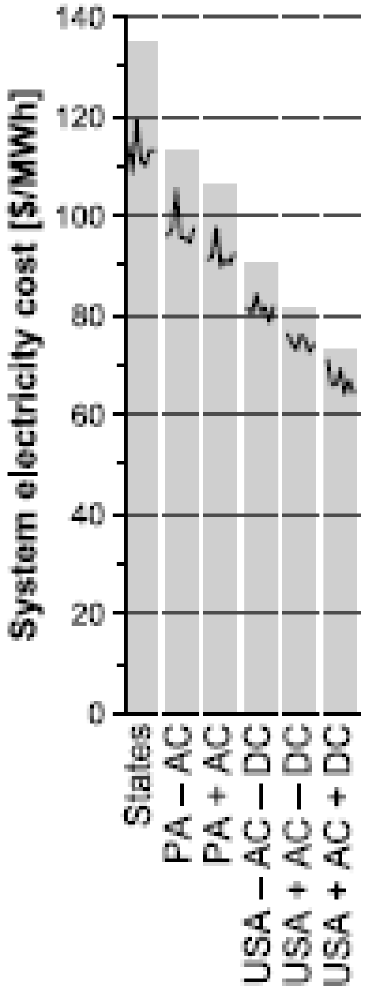
**Source:** DOE, National Transmission Needs Study, October 2023, Table VI-4, p. 131-133

# MIT Study: Cost Reductions Enabled by Interregional Transmission

TRANSMISSION ↑

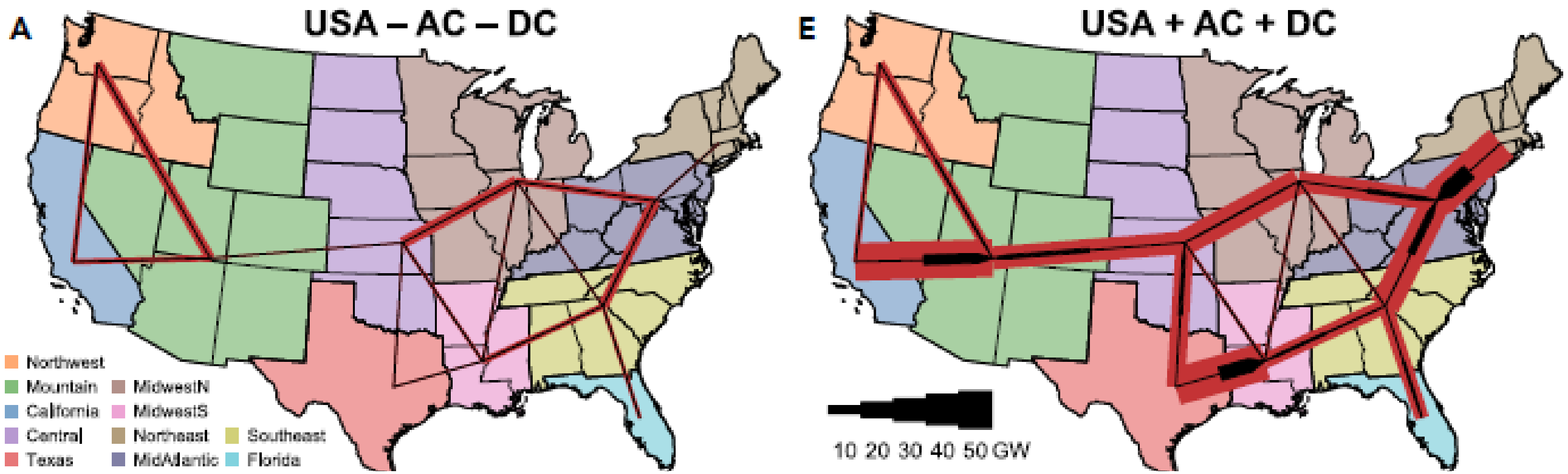



TOTAL COST ↓




**Key Result:** A more robust national grid would reduce the total cost of decarbonizing the grid … but (higher-cost) regional and more local solutions may also be feasible

**Optimal Transmission Build:**
**With and Without National Transmission Coordination**



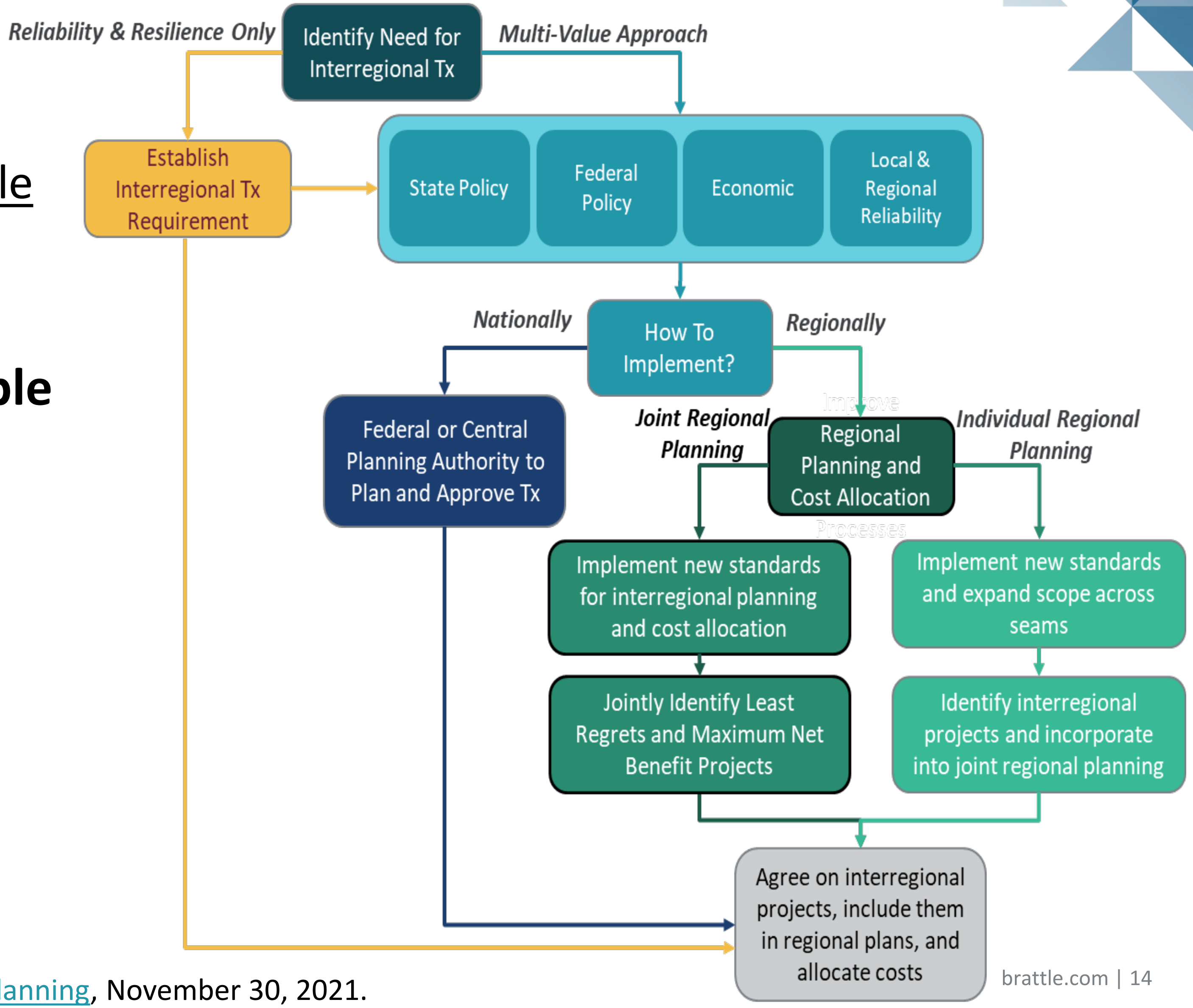

P. R. Brown and A. Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule, December 11, 2020.

# Options for Improving Interregional Planning Processes

While national studies show there are benefits of interregional transmission, these studies do not create an actionable "need" for approving projects

**Four paths can be pursued simultaneously, identifying actionable transmission needs through:**

1. **New Interregional Tx requirements?**
2. **New Federal planning?**
3. **Improve joint RTO planning**
4. **Expand planning by individual RTOs**




*Source*: A Roadmap to Improved Interregional Transmission Planning, November 30, 2021.

# Considerations for Planning New Interregional Transmission

**To be able to plan interregional transmission that reduces costs and improves reliability compared to regional or local solutions requires that we:**

- Fully and efficiently utilize interregional transmission in energy markets and for resource adequacy
- Improve planning models:
  - Improve representation of <u>neighboring regions</u> in model footprint to capture diversity
  - Capture impacts of <u>challenging conditions</u> and extreme events, such as heat waves or cold snaps
    - Simultaneous spikes in loads, fuel prices, generation and transmission outages, resilience challenges
    - LBNL study: 40-80% of annual transmission value is concentrated in top 5% of all hours
  - Integrate/combine all <u>benefit metrics</u> of neighboring regions in economic analyses
  - Recognize the full <u>resource adequacy value</u> of interregional transfer capability (even if non-firm or not committed to capacity imports) to reflect load and resource diversity
- Proactively evaluate (including in regional planning processes) if <u>interregional solutions</u> exist that are more effective than regional or local solutions
  - Recognize regional/interregional benefits, including avoided cost of regional/local solutions

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2. The poor utilization of interregional transmission across market seams requires intertie optimization
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# First Step: More Efficiently Utilize Interregional Transmission

**The time is ripe to consider "intertie optimization" to reduce seam-related inefficiencies!**

- NYISO, ISO-NE, and Potomac Economics have called for intertie optimization in 2010-2011 to address seam-related inefficiencies, but only "coordinated transaction scheduling"(CTS) was implemented at the time
- A decade later, market monitors continue to document seams-related inefficiencies, noting that CTS has not been effective, and <u>recommending intertie optimization</u>
- The Western energy imbalance markets and European "market coupling" experiences have shown that intertie optimization between BAAs offers substantial benefits—reducing costs, improving reliability and renewable integration—
  - Has dramatically improved efficient utilization of interregional transmission
  - Does not require "cost allocation" for new transmission
  - Provides value of optimized transactions directly to transmission owners and their customers
  - Widely embraced and FERC approved

# Interregional Transmission is Poorly Utilized

**For example, in the 2022 PJM State of the Market Report, the Market Monitor notes:**

- Price differences across the MISO-PJM seam exceeded \$10/MWh during 3,182 hours; yet during 1,570 (49%) of these hours, market flows were inconsistent with those price differences, exporting power from the higher-priced market to the lower-priced market
- On PJM-NYISO interties, price differences exceeded \$10/MWh during 4,178 hours, with inconsistent market flows during 1,667 (40%) of these hours

**Potomac Economics similarly observes intertie inefficiencies:**

- On MISO's seams: "more than 40 percent of … transactions are ultimately unprofitable"
- Between NYISO and ISO-NE: the efficiency of real-time trades has been deteriorating, achieving "optimal" RT transactions during only 11% of all trading periods in 2022, down from 23% in 2018

**This inefficiency is particularly pronounced and consequential in real-time markets, for which forecasting price differences for the next 1-2 hours is becoming increasingly more difficult**

- **Day-ahead**: average (absolute) value of 2022 PJM-NYISO price difference of \$12.94/MWh with price differences changing signs 3.1 times per day. With absolute PJM-MISO difference = \$9/MWh, changing sign 4.1 times/day
- **Real-time**: average (absolute) PJM-NYISO price difference of \$115.36/MWh with sign changing sign 47.9 times each day. With absolute PJM-MISO difference = \$99.86/MWh, changing sign 62.9 times/day

# Poorly-Utilized Interregional Transmission has Long Been Documented

**Potomac Economics has documented inefficient utilization of interregional transmission interties since 2003**

- David Patton, Coordinated Interchange Recommendations, March 13, 2003 (Presentation to New England RTO Working Group).

**In 2010, Potomac Economics estimated that optimizing interties between MISO, PJM, NYISO, ISO-NE, and Canadian system operators would conservatively yield between $160-300 million in annual cost savings**

- See Analysis of the Broader Regional Markets Initiatives, pp. 10-13

**In 2011, NYISO and ISO-NE proposed to address these seams-related inefficiencies through intertie optimization**

- See Interregional Interchange Scheduling (IRIS) Analysis and Options

**Yet, little has changed and interregional interties continue to be utilized poorly**

# The 2011 Intertie Optimization Proposal by NYISO and ISO-NE

**In 2011, NYISO and ISO-NE proposed to implement intertie optimization to address the inefficiencies from poor utilization of interregional transmission**

- ISOs agreed with concerns raised by its Market Monitor since 2003
- The ISOs' analysis showed that "too little power is flowing in the correct direction more than 4000 hours per year." "Nearly half of the time that New England has higher-cost generation on the margin than New York, the net scheduled flow is westbound into New York"
- "The price difference exceeds $5 per MWh (in absolute value) more than half of the year, and exceeds $10 per MWh (in absolute value) nearly one-third of the year [when] there is transmission capacity available to schedule additional transfers across the interface." "[T]otal energy expenditures would be on the order of one to two hundred million dollars lower annually—or perhaps half a million dollars per day lower—if the real-time inter-regional interchange system produced efficient tie schedules."
- The three root causes are:
  - **1. Latency Delay**. The time delay between when the tie is scheduled and when power flows, during which time system conditions and LMPs may change (a factor magnified in impact by the increasing volatility of real-time market conditions)
  - **2. Non-economic Clearing**. The ISOs make decisions about which tie schedule requests to accept without economic coordination, producing inefficient schedules
  - **3. Transaction Costs**. The fees and charges levied by each ISO on external transactions serve as a disincentive to engage in trade, impeding price convergence and raising total system costs

# NYISO & ISO-NE Recommended Intertie Optimization in 2011, but CTS was implemented instead

**NYISO & ISO-NE offered fully-specified, implementable designs for two possible solutions:**

- Intertie Optimization: similar to the least-cost economic dispatch system used internally for each ISO's energy market, it relies on "market-based offers to determine the real-time schedule of energy interchange between their interconnected transmission networks" (see updated optimization framework*)
- Coordinated Transaction Scheduling: facilities bilateral trading in real time through a simplified bid format (called an interface bid) and coordinated acceptance of interface bids by the ISOs (using an improved clearing rule and forecasts of real-time prices)

**The ISOs recommended the Intertie Optimization as their preferred solution because:**

- Intertie optimization "is the more efficient solution" (and consistent with existing ISO roles of independent LMP-based market and settlement administrators)
- The CTS system was not expected to produce as complete a price convergence between regions

**Only CTS was implemented between NYISO and ISO-NE (and later PJM and MISO):**

- Concerns were raised that intertie optimization may unnecessarily displace bilateral trading
- It was hoped that CTS, as the less complex solution, might be almost as efficient

* Zhao, Litvinov, and Zheng, "A Marginal Equivalent Decomposition Method and Its Application to Multi-Area Optimal Power Flow Problems," IEEE Transactions on Power Systems, Volume 29, Issue 1 (2014). (Successfully tested large-scale simulations of a "marginal equivalence" approach that works for both RTO and non-RTO seams)

# MISO and NYISO Market Monitor: CTS has not been successful in reducing seams-related inefficiencies

**The Potomac Economics (the NYISO and MISO Independent Market Monitor) has been documenting the ineffectiveness of CTS:**

- For example, in the MISO 2021 State of the Market Report, the IMM notes that CTS between MISO and PJM: *"has produced very little of the sizable savings it could generate"* and that *"more than 40 percent of the current CTS transactions are ultimately unprofitable"* (at xx and 90, emphasis added)

**To address these continued inefficiency the IMM recommends to modify CTS so it can better approximate intertie optimization:**

- "we recommend the RTOs consider modifying the CTS to clear transactions every five minutes through [the Unit Dispatch System, UDS] based on the most recent five-minute prices in the neighboring RTO area"
- Doing so was estimated to offer cost savings of $23m for transactions with PJM and $44m for transactions with SPP

**Table 14: CTS with Five-Minute Clearing Versus Current CTS**
2021

| | Percent of Intervals Adjusted | Production Cost Savings | Profits | Percent Unprofitable |
|---|---|---|---|---|
| **PJM** | | | | |
| **Current CTS** | 9.7% | $7,203,734 | $199,456 | 39.4% |
| **5-Minute CTS** | 77.5% | $23,207,329 | $11,765,360 | 13.8% |
| **SPP** | | | | |
| **5-Minute CTS*** | 89.6% | $44,089,866 | $25,984,814 | 22.1% |

* Results omit Feb. 13-19 when SPP experienced very high prices from the Arctic Event.

Source: MISO 2021 STATE OF THE MARKET REPORT (potomaceconomics.com)

# PJM Market Monitor: has been recommending intertie optimization because CTS has not been effective

**The PJM Market Monitor has recommended to reconsider intertie optimization since 2014:**

- In the 2022 PJM State of the Market Report (at 105), the PJM Market Monitoring Unit (MMU) repeats the recommendation it has made since 2014: "The MMU recommends that 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"

**The recommendation is supported by a finding of inefficient intertie schedules that are inconsistent with seams-related price differences during almost half of all trading periods:**

Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: 2022

| Price Difference Range (Greater Than or Equal To) | Inconsistent Hours | Percent of Inconsistent Hours | Consistent Hours | Percent of Consistent Hours |
|---|---|---|---|---|
| $0.00 | 4,176 | 100.0% | 4,584 | 100.0% |
| $1.00 | 3,773 | 90.3% | 4,190 | 91.4% |
| $5.00 | 2,517 | 60.3% | 2,737 | 59.7% |
| $10.00 | 1,570 | 37.6% | 1,612 | 35.2% |
| $15.00 | 989 | 23.7% | 1,056 | 23.0% |
| $20.00 | 673 | 16.1% | 700 | 15.3% |
| $25.00 | 490 | 11.7% | 531 | 11.6% |
| $50.00 | 150 | 3.6% | 243 | 5.3% |
| $75.00 | 65 | 1.6% | 137 | 3.0% |
| $100.00 | 38 | 0.9% | 94 | 2.1% |
| $200.00 | 26 | 0.6% | 34 | 0.7% |
| $300.00 | 19 | 0.5% | 15 | 0.3% |
| $400.00 | 17 | 0.4% | 8 | 0.2% |
| $500.00 | 15 | 0.4% | 6 | 0.1% |

Table 9-29 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: 2022

| Price Difference Range (Greater Than or Equal To) | Inconsistent Hours | Percent of Inconsistent Hours | Consistent Hours | Percent of Consistent Hours |
|---|---|---|---|---|
| $0.00 | 3,463 | 100.0% | 5,297 | 100.0% |
| $1.00 | 3,193 | 92.2% | 5,021 | 94.8% |
| $5.00 | 2,327 | 67.2% | 3,834 | 72.4% |
| $10.00 | 1,667 | 48.1% | 2,511 | 47.4% |
| $15.00 | 1,206 | 34.8% | 1,664 | 31.4% |
| $20.00 | 912 | 26.3% | 1,173 | 22.1% |
| $25.00 | 709 | 20.5% | 881 | 16.6% |
| $50.00 | 360 | 10.4% | 360 | 6.8% |
| $75.00 | 220 | 6.4% | 209 | 3.9% |
| $100.00 | 143 | 4.1% | 133 | 2.5% |
| $200.00 | 49 | 1.4% | 54 | 1.0% |
| $300.00 | 22 | 0.6% | 28 | 0.5% |
| $400.00 | 14 | 0.4% | 24 | 0.5% |
| $500.00 | 9 | 0.3% | 20 | 0.4% |

Source: 2022 State of the Market Report for PJM (monitoringanalytics.com)

# Experience with Intertie Optimization: Western EIM and EIS

**The Western EIM and Western EIS have been created to optimize in real-time the available transmission across the interregional seams between multiple Balancing Areas in the WECC**

- They represents the most relevant examples of the significant cost savings that intertie optimization between BAs can offer … along with reliability, resilience, and renewable integration benefits
- Depancaked WEIM and WEIS transactions are scheduled on a 15-minute/ 5-minute basis after all bilateral trading has closed (approximately 20 minutes before each real-time operating period), using transmission that remains available and otherwise would go unutilized
  - Value of transactions accrues to the neighboring BAAs and other entities that contribute available transmission
- The available experience shows that real-time energy transactions optimized by neighboring system operators **offers significant value beyond what can be achieved through bilateral trades**
- In response to WEIM and WEIM success, market operators are now developing the Extended Day Ahead Market (EDAM) and Markets+ to fully optimize interregional transmission on a day-ahead basis as well

**Flow-based "Market Coupling" in central and western Europe (for transmission left available after bilateral day-ahead and intra-day trading closes) is currently expanded to Scandinavia**

# CAISO's Subscriber-PTO (SPTO) Proposal: optimizing available capacity on interregional merchant transmission projects

**CAISO developed the SPTO framework to integrate unutilized capacity on merchant transmission lines into regional and interregional DA and RT energy markets**

- Applies to interregional merchant transmission lines (such as TransWest Express, an HVDC line from Wyoming to Utah and Southern California) whose costs are recovered from "subscribers" … rather than from native load customers through CAISO regulated transmission rates
- The SPTO proposal recognizes that fully integrating interregional merchant lines into DA and RT energy markets (and compensating the holders of the transmission rights for market-based use) offers substantial benefits to CAISO, its customers, and the larger western power market

**Summary of the SPTO design** (FERC approval in Docket ER23-2917)

- The merchant SPTO facility is put under CAISO operational control
- Priority rights for subscriber schedules (perfect congestion hedge)
- Unscheduled merchant transmission capacity (held by subscriber or project owner) is made available for regional and interregional "market use" in both day-ahead and real-time
- CAISO will optimize SPTO capacity made available, including inter-regionally in EIM and EDAM
- CAISO will pay a "Non-subscriber Usage Charge" to compensate the merchant facility for market transactions
  - Paid from (and capped at) CAISO's transmission access charge to avoid rate pancaking

# Contents

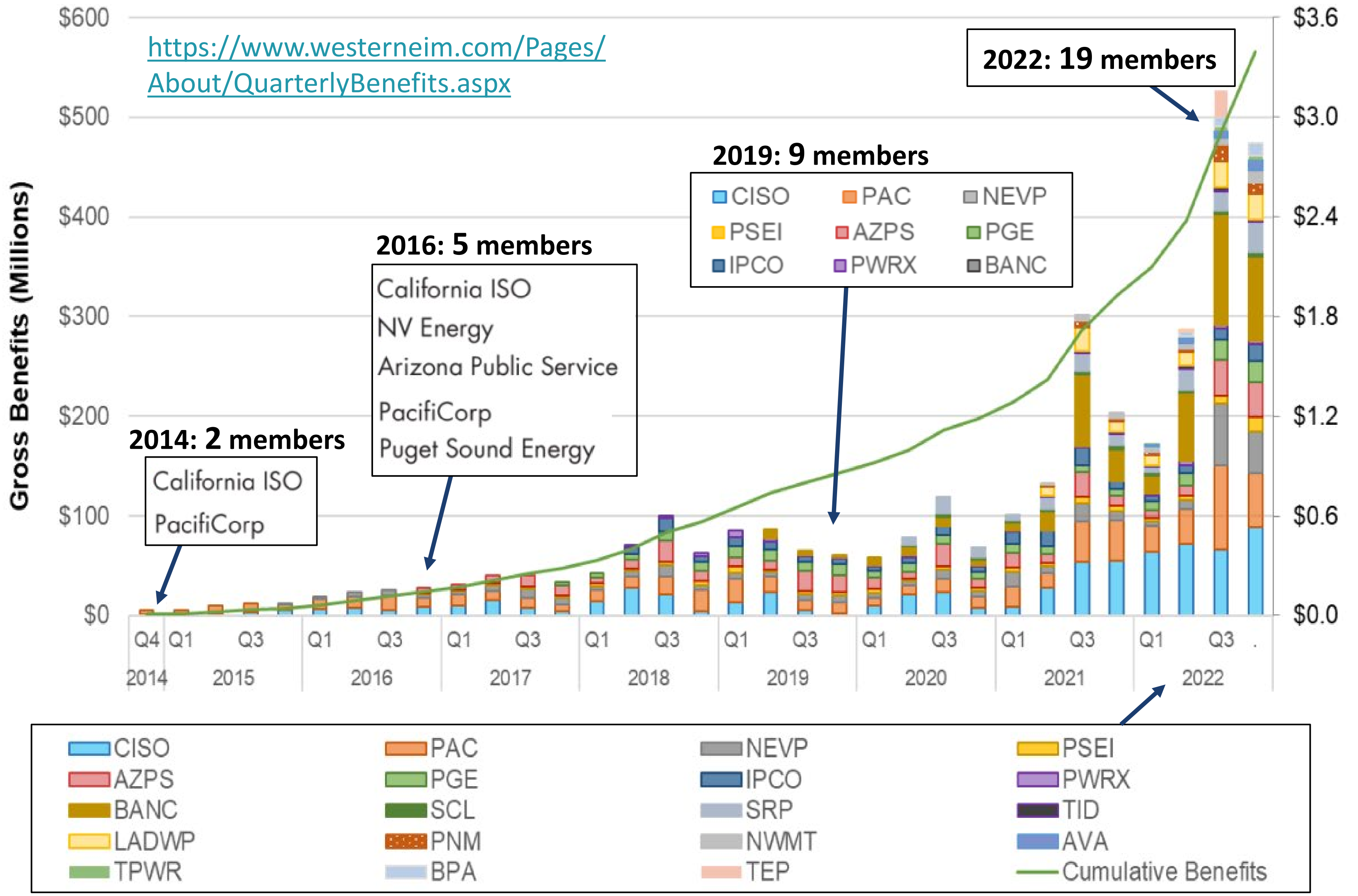
1. The value, need, and planning of interregional transmission
2. The poor utilization of interregional transmission across market seams requires intertie optimization
3. The value of intertie optimization

# Experience with Intertie Optimization: Western EIM and EIS

**The Western EIM and Western EIS have been created to optimize in real-time the available transmission across the interregional seams of multiple Balancing Areas in the WECC**

- They represents the most relevant examples of the significant cost savings that intertie optimization between BAs can offer … along with reliability, resilience, and renewable integration benefits
- WEIM and WEIS transactions are incremental to a baseline of bilateral trades, scheduled on a 15-minute/ 5-minute basis after all bilateral trading closes (approx. 20 minutes before each real-time operating period)
- Experience shows this **offers significant value beyond what can be achieved through bilateral trades**
- For example, as shown on next slide, WEIM has achieved:
  - **Between $170 million and $530 million in savings during each quarter of 2022,**
  - **Cumulative savings of over $4 billion since its inception**
- In response to WEIM and WEIM success, market operators are now developing the Extended Day Ahead Market (EDAM) and Markets+ to optimize interregional transmission on a day-ahead basis as well
  - Market-based congestion/transfer revenues accrue to entity contributing the transmission rights/capability

# WEIM Benefits: the value of transmission optimization within and across multiple Balancing Areas in RT energy markets





**2022**

# Estimated Value of Intertie Optimization: SPP, MISO and PJM

**Volatility of price differences between SPP, MISO, and PJM shows that intertie optimization is needed to capture 20-30% of the total real-time transmission value**

- Our analysis 2020-2022 price differences point to a high “book-end” value if interregional transfer capacity could be used more optimally for RT energy market transactions
  - **Bilateral trades** that respond to observed RT price differences with a 1-2 hour delay would typically **capture only 70-80%** of the total energy value of interties, including during reliability events
  - The value that cannot be captured by through bilateral trades consequently is roughly **20-30% of the total real-time value** (assuming a 1-2 hour delay of trades in response to observed prices)

**This represents an average value of approx. $50-60 million/year for every 1,000 MW of intertie capacity**

  - It can only be captured by system operators through automated operational means, such as intertie optimization or an interregional energy imbalance market (similar to the Western EIM or EIS)

**For merchant transmission lines, intertie optimization revenues would need to accrue to either the transmission owner or its subscribers**

  - See CAISO Subscriber PTO proposal

# Estimated value of intertie optimization (detailed results)

**Approach (based on LBNL framework):** Value of 1000 MW of trade based on differences in hourly real-time energy prices for nodes in western SPP, central MISO, and western PJM

| | | | SPP > MISO | MISO > SPP | MISO > PJM | PJM > MISO | SPP > PJM | PJM > SPP |
|---|---|---|---|---|---|---|---|---|
| **Value with No Trading Delay ($ million)** | | [1] | | | | | | |
| | **2020** | | $91 | $27 | $26 | $23 | $93 | $26 |
| | **2021** | | $189 | $136 | $69 | $44 | $222 | $143 |
| | **2022** | | $338 | $53 | $144 | $58 | $410 | $39 |
| **Value with 1 Hour Delay ($ million)** | | [3] | | | | | | |
| | **2020** | | $76 | $10 | $13 | $11 | $79 | $10 |
| | **2021** | | $165 | $108 | $46 | $22 | $198 | $117 |
| | **2022** | | $307 | $23 | $104 | $20 | $384 | $14 |
| **Value with 2 Hour Delay ($ million)** | | [4] | | | | | | |
| | **2020** | | $71 | $7 | $11 | $9 | $75 | $7 |
| | **2021** | | $150 | $95 | $39 | $17 | $185 | $107 |
| | **2022** | | $290 | $8 | $91 | $7 | $372 | $3 |
| **Value of Intertie Optimization ($ million)** | | [1] - [3] | | | | | | |
| | **1 Hour Delay: 2020** | | $15 | $17 | $13 | $12 | $14 | $16 |
| | **2021** | | $24 | $28 | $24 | $21 | $24 | $26 |
| | **2022** | | $31 | $30 | $40 | $39 | $26 | $25 |
| | | [1] - [4] | | | | | | |
| | **2 Hour Delay: 2020** | | $20 | $20 | $16 | $13 | $18 | $19 |
| | **2021** | | $39 | $41 | $30 | $26 | $37 | $37 |
| | **2022** | | $48 | $46 | $53 | $51 | $38 | $35 |

| Bidirectional Intertie | | SPP-MISO | MISO-PJM | SPP-PJM |
|---|---|---|---|---|
| **Annual Average Value with No Trading Delay ($ million)** | [1] | $278 | $122 | $311 |
| **Annual Average Value with 1 Hour Delay ($ million)** | [3] | $230 | $72 | $267 |
| **% Value Lost Due to Delay** | 1 - ([3]/[1]) | 17% | 41% | 14% |
| **Annual Average Value with 2 Hour Delay ($ million)** | [4] | $206 | $58 | $250 |
| **% Value Lost Due to Delay** | 1 - ([4]/[1]) | 26% | 52% | 20% |
| **Annual Average Value of Intertie Optimization ($ million)** | | | | |
| **One hour** | [1] - [3] | $48 | $50 | $43 |
| **Two hour** | [1] - [4] | $71 | $63 | $61 |

**Approx. $50-60 million/yr per 1000 MW**

# FERC Has the Authority to Implement Intertie Optimization

**Norman Bay and Vivien Chum (Willkie Farr & Gallagher LLP):**

- FERC has long recognized the inefficiencies of market seams. *See* Order No. 888 & Order No. 2000
- FERC's authority to address seams issues is clear given its duty to ensure just and reasonable rates
- There is well established precedent for FERC to address market seams:
  - Coordinated Transaction Scheduling (ISO-NE-NYISO; NYISO-PJM; and PJM-MISO)
  - Western EIM and EIS
  - FERC precedent with respect to CTS: recognizing the value of "Tie Optimization" and leaving the door open. *See NYISO*, 139 FERC ¶ 61,048 (2012) (recognizing the possibility of replacing CTS with a "different methodology for scheduling external transactions (i.e., Tie Optimization or a superior alternative), if it is determined that such changes could result in greater cost savings")
- If the RTOs/ISOs propose intertie optimization, FERC has the clear authority to accept the filing under section 205. FERC would also be able to require intertie optimization under FPA section 206

# The Bottom Line

**The time is ripe to consider "intertie optimization" to reduce seam-related inefficiencies and barriers to interregional transmission development, including for merchant lines that provide regional market benefits without regulated cost recovery from all customers**

- NYISO, ISO-NE, and Potomac Economics have called for intertie optimization in 2010-2011 to address seam-related inefficiencies, but only CTS was implemented
- A decade later, market monitors continue to document seams-related inefficiencies, noting that CTS has not been effective, and <u>recommending intertie optimization</u>
- The Western energy imbalance markets and European "market coupling" experiences have shown that intertie optimization between BAAs offers substantial benefits: reducing costs, improving reliability and renewable integration—dramatically improving utilization of interregional transmission
  - EDAM and Markets+ will further enhance the value of intertie optimization across BAA seams in the West
- CAISO's new "Subscriber PTO" proposal integrates available capacity on merchant transmission projects for optimization in the regional and interregional energy markets
- FERC has the authority to approve/implement intertie optimization under either section 205 or 206 of the FPA

**Thank You!**

**Comments and Questions?**

See also: Frequently-asked Questions

Additional Slides

# About the Speaker


## Johannes P. Pfeifenberger

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**Johannes (Hannes) Pfeifenberger**, a Principal at The Brattle Group, is an economist with a background in electrical engineering and over twenty-five years of experience in wholesale power market design, renewable energy, electricity storage, and transmission. He also is a Visiting Scholar at MIT's Center for Energy and Environmental Policy Research (CEEPR), a Senior Fellow at Boston University's Institute of Sustainable Energy (BU-ISE), a IEEE Senior Member, and currently serves as an advisor to research initiatives by the U.S. Department of Energy, the National Labs, and the Energy Systems Integration Group (ESIG).

Hannes specializes in wholesale power markets and transmission. He has analyzed transmission needs, transmission benefits and costs, transmission cost allocations, and renewable generation interconnection challenges for independent system operators, transmission companies, generation developers, public power companies, industry groups, and regulatory agencies across North America. He has worked on transmission matters in SPP, MISO, PJM, New York, New England, ERCOT, CAISO, WECC, and Canada and has analyzed offshore-wind transmission challenges in New York, New England, and New Jersey.

He received an M.A. in Economics and Finance from Brandeis University's International Business School and an M.S. and B.S. ("Diplom Ingenieur") in Power Engineering and Energy Economics from the University of Technology in Vienna, Austria.

# Examples of Brattle Reports on Regional and Interregional Transmission Planning and Benefit-Cost Analyses

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

PREPARED FOR
WIRES

Link: Well-Planned Transmission

PREPARED BY
Judy W. Chang
Johannes P. Pfeifenberger

May 2016

THE Brattle GROUP

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

PREPARED FOR
WIRES

Link: Effective Transmission Planning

PREPARED BY
Johannes P. Pfeifenberger
Judy W. Chang
Akarsh Sheilendranath

April 2015

*The Brattle Group*

Link: Transmission Benefits

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

July 2013

Judy W. Chang
Johannes P. Pfeifenberger
J. Michael Hagerty

Link: Diversity Value

BU
Boston University Institute for Sustainable Energy

The Value of Diversifying Uncertain Renewable Generation through the Transmission System

September • 2020

A Roadmap to Improved Interregional Transmission Planning

Link: Interregional Roadmap

PREPARED BY
Johannes P. Pfeifenberger
Kasparas Spokas
J. Michael Hagerty
John Tsoukalis

November 30, 2021

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

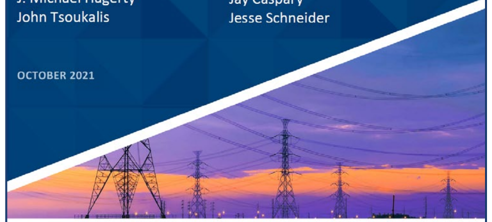
Link: Brattle Grid Strategies

PREPARED BY

*The Brattle Group:*
Johannes Pfeifenberger
Kasparas Spokas
J. Michael Hagerty
John Tsoukalis

*Grid Strategies:*
Rob Gramlich
Michael Goggin
Jay Caspary
Jesse Schneider

OCTOBER 2021



Brattle
GRID STRATEGIES LLC

Summarizes proven approaches to quantifying various benefits

# The Need for and Value Proposition of Interregional Transmission

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

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

# National Studies Show Large Benefit of Interregional Transmission

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

*Source*: A Roadmap to Improved Interregional Transmission Planning, November 30, 2021.

# Limitations of National Studies

**Although existing studies demonstrate the benefits of interregional transmission, they have not been successful in motivating improved interregional planning or actual transmission project developments. The reasons include some or all of the following:**

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

# National Studies are Not a Substitute for Transmission Planning

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

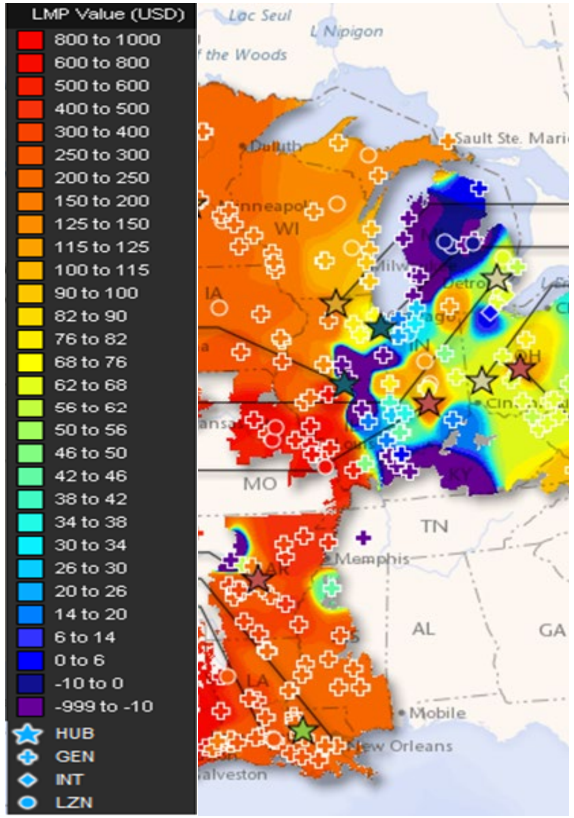
- Various "macro grid" studies show how much transmission capacity might be cost effective between certain regions, but they fail to:
  - Consider existing **transmission planning criteria** (e.g., reliability, stability, size of largest contingencies)
  - Pinpoint **specific locations on the power system**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

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

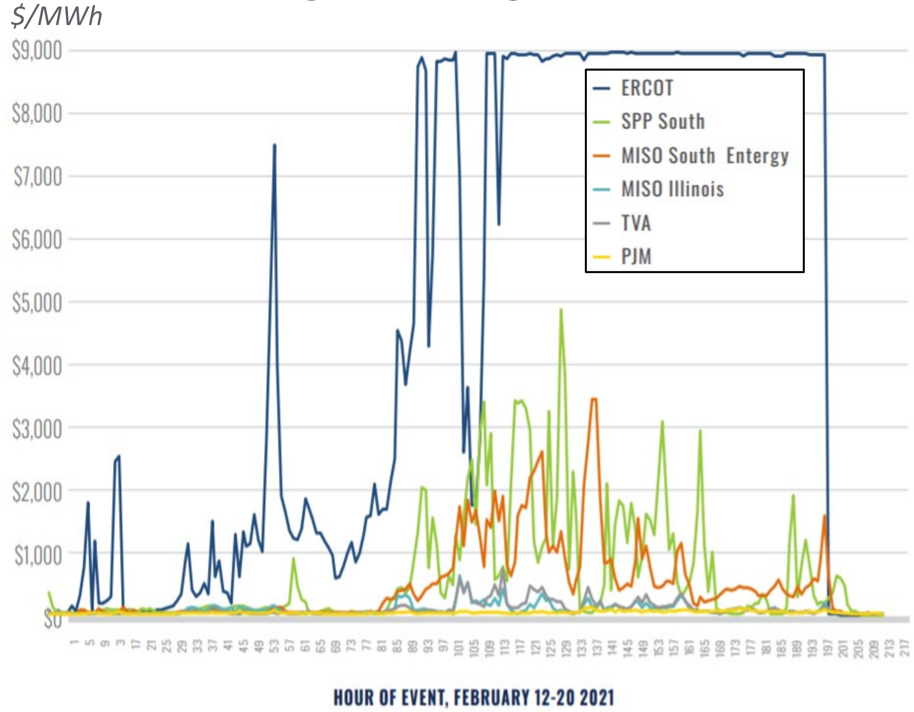
# Case Study: Winter Storm Uri

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

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




**Electricity Price Differences Between Regions During Uri**




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

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

# Framework for More Proactive Transmission Planning*

**FERC NOPR efforts and available experience point to proven planning practices that can reduce total system costs and risks, but are rarely used today:**

1. **Proactively and holistically plan for future generation and load** by incorporating realistic projections of all needs: the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investments. Avoid siloed, incremental planning processes.
2. **Account for the full range of transmission needs** and **use multi-value planning** to comprehensively identify investments that cost-effectively address all categories of needs and benefits
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account all transmission needs for a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events
4. **Use comprehensive transmission network portfolios** to address system needs and **cost allocation** more efficiently and less contentiously than a project-by-project approach
5. **Jointly plan inter-regionally across neighboring systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits

* Brattle & Grid Strategies Report: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

# Brattle Group Publications on Transmission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Pfeifenberger, DeLosa, et al., The Benefit and Urgency of Planned Offshore Transmission, for ACORE, ACP, CATF, GridLab, and NRDC, January 24, 2023.
Brattle and ICC Staff, Illinois Renewable Energy Access Plan: Enabling an Equitable, Reliable, and Affordable Transition to 100% Clean Electricity for Illinois, December 2022.
Pfeifenberger et al., New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report, October 26, 2022.
Pfeifenberger, DeLosa III, Transmission Planning for a Changing Generation Mix, OPSI 2022 Annual Meeting, October 18, 2022.
Pfeifenberger, Promoting Efficient Investment in Offshore Wind Transmission, DOE-BOEM Atlantic Offshore Wind Transmission Economics & Policy Workshop, August 16, 2022.
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Pfeifenberger, Planning for Generation Interconnection, Presented at ESIG Special Topic Webinar: Interconnection Study Criteria, May 31, 2022.
RENEW Northeast, A Transmission Blueprint for New England, Prepared with Borea and The Brattle Group, May 25, 2022.
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Pfeifenberger, The Benefits of Interregional Transmission: Grid Planning for the 21st Century, US DOE National Transmission Planning Study Webinar, March 15, 2022.
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Chang, Pfeifenberger, Sheilendranath, Hagerty, Levin, and Jiang, "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value," April 2019 and "Response to Concentric Energy Advisors' Report on Competitive Transmission," August 2019.
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Pfeifenberger, Chang, and Sheilendranath, "Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid," WIRES and Brattle, April 2015.
Chang, Pfeifenberger, Hagerty, "The Benefits of Electric Transmission:  Identifying and Analyzing the Value of Investments," on behalf of WIRES, July 2013.
Chang, Pfeifenberger, Newell, Tsuchida, Hagerty, "Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process," October 2013.
Pfeifenberger and Hou, "Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning," on behalf of SPP, April 2012.
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# Brattle Group Practices and Industries

## ENERGY & UTILITIES

Competition & Market Manipulation
Distributed Energy Resources
Electric Transmission
Electricity Market Modeling & Resource Planning
Electrification & Growth Opportunities
Energy Litigation
Energy Storage
Environmental Policy, Planning and Compliance
Finance and Ratemaking
Gas/Electric Coordination
Market Design
Natural Gas & Petroleum
Nuclear
Renewable & Alternative Energy

## LITIGATION

Accounting
Analysis of Market Manipulation
Antitrust/Competition
Bankruptcy & Restructuring
Big Data & Document Analytics
Commercial Damages
Environmental Litigation & Regulation
Intellectual Property
International Arbitration
International Trade
Labor & Employment
Mergers & Acquisitions Litigation
Product Liability
Securities & Finance
Tax Controversy & Transfer Pricing
Valuation
White Collar Investigations & Litigation

## INDUSTRIES

Electric Power
Financial Institutions
Infrastructure
Natural Gas & Petroleum
Pharmaceuticals & Medical Devices
Telecommunications, Internet, and Media
Transportation
Water

# Our Offices


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