RTO Market Seams:

Impacts on Operations, Planning, and Pricing

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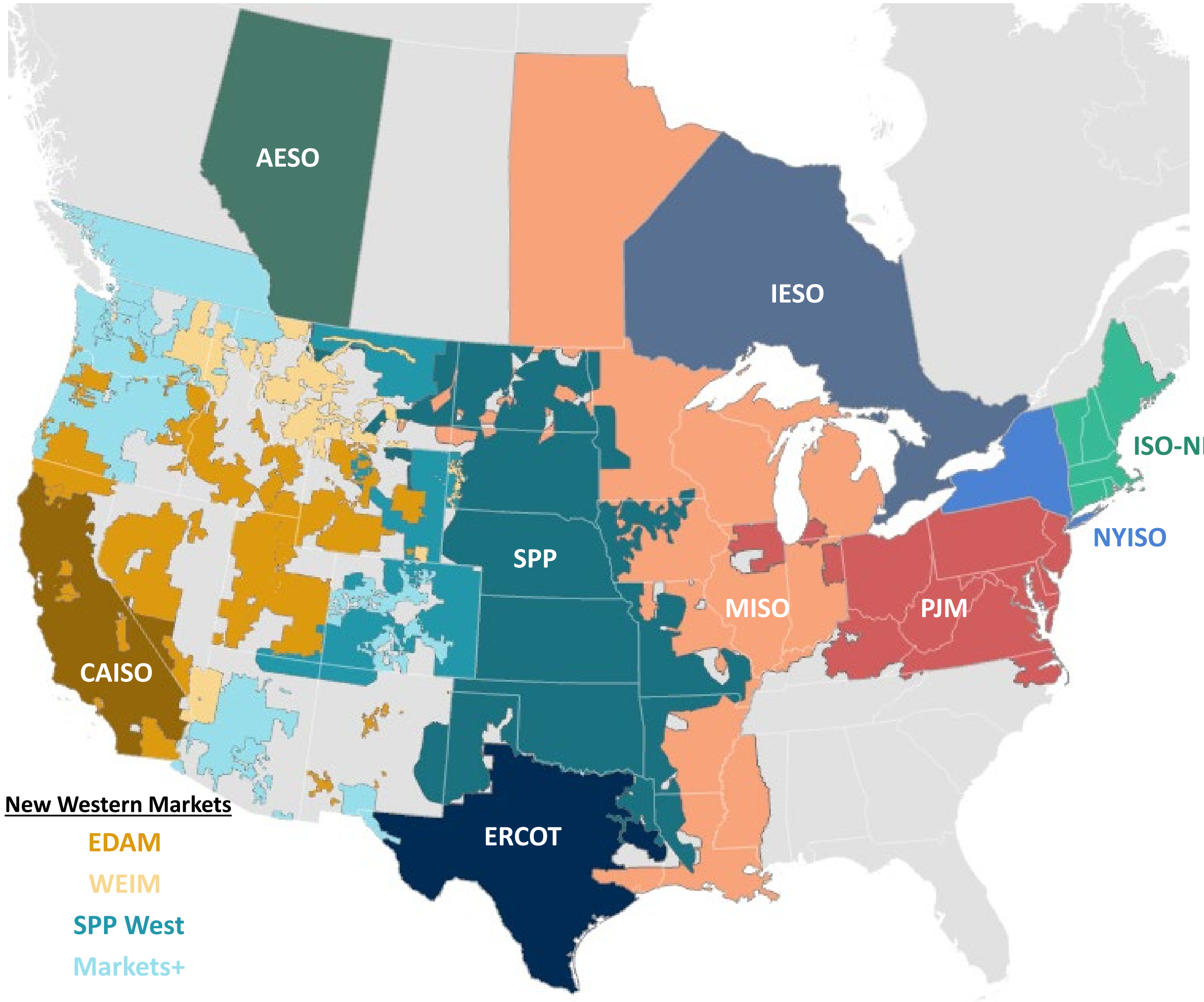
Brattle

Topics discussed today

North American RTOs/ISOs and their intertwined seams



Intertwined seams of US regional grid operators create complex operational, market, and planning challenges

- **Challenge first arose in late 1990s/early 2000 when MISO was formed and some midwestern utilities (such as ComEd and AEP) chose to join PJM**
  - To address inefficiencies, FERC required MISO and PJM to "depancake" their seam and address planning and congestion management challenges
- **Entergy joining MISO in 2013 (to create MISO-South) created additional seams challenges**
  - MISO loop flows over SPP and TVA highlighted the limitations of seams-management tools developed by MISO and PJM
- **Significant concerns now exist over new EDAM/Markets+ seam in WECC**

Indications of seams-related inefficiencies

NREL's 2024 Interregional Transmission Barriers Report documents and analyzes seams-related inefficiencies

- Uneconomic Flows: Frequently power flows from higher-price areas to lower-price areas.
- High Price Differentials: Significant spreads in power prices between regions when transmission is not constrained indicates opportunities to reduce customer costs
- Underutilized Transmission Capacity: in combination with persistent price differences, means that transmission assets are not being used efficiently to bring lower-priced power to higher-priced regions.
- Lack of Transparency on Inefficiencies**:** lack of transparency in interchange transactions is an obstacle to identifying inefficiencies—and opaqueness is more likely to occur in areas without regional organized markets (e.g., lack of market monitoring)

Seams-related inefficiencies also relate to loop flows imposed by one region's market-dispatch on its neighboring regions, causing both reliability concerns and congestion management challenges

SPP-MISO-PJM initiatives to address seams-related challenges

SPP, MISO, and PJM manage their market seams through Joint Operating Agreements (JOAs) designed to improve reliability and economic efficiency. The RTOs have similar JOAs with neighboring non-market regions.

Examples of these SPP-MISO-PJM seams-management efforts include:

- MISO-PJM Joint and Common Market initiatives that focus on reducing congestion along the shared border, managing loop flows and optimizing generation dispatch through a market-to-market (M2M) framework, coordinating outages, exchanging data, and transmission planning
- MISO-SPP Coordinated System Plan (CSP): A structured 18-month transmission planning cycle aimed at identifying mutually beneficial transmission solutions to improve grid reliability and economics
- MISO-SPP Joint Targeted Interconnection Queue Study (JTIQ): A specialized initiative to identify and build transmission upgrades needed to address constraints holding up new generator interconnections, with shared cost-sharing mechanisms between the two RTOs
- SPP-MISO and MISO-PJM Interregional Planning Stakeholder Advisory Committees (IPSAC) and SPP-MISO-PJM interregional coordination

Sample of seams-related efforts and reports

Examples of recent seams-related reports and initiatives:

FERC, Seams Coordination in the Western Interconnection, Staff Whitepaper (2025)*
Doying, Managing Seams: Market Coordination in Western Wholesale Energy Market, Grid Strategies (2025)*
MISO-SPP and MISO-PJM Seams Management Working Group
MISO-SPP, Common Seams Initiative (CPI), 2025 update
MISO-PJM, Joint and Common Market Drill-Down Report (2025)
Pfeifenberger, Intertie Optimization: Achieving Efficient Use of Interregional Transmission, IEEE PES (2025)
ACORE, Billions in Benefits: A Path for Expanding Transmission Between MISO and PJM (2025)
WPTF & PGP, Exploring Potential Seams Issues Between Proposed Western DA Electricity Market (2024)
NREL Report: Barriers and Opportunities to Realize the System Value of Interregional Transmission (June 2024)
MISO-PJM JOA Biennial Review (2024)
Pfeifenberger et al., The Need for Intertie Optimization, Brattle-Wilkie (2023)
OMS-RSC Seams Study and Seams Liaison Committee (SLC), Seams Coordination Effort (2018-2022)

Seams inefficiencies have been recognized for two decades:

NARUC, Electric Transmission Seams: A Primer White Paper (2015)
Spees, Pfeifenberger, Seams Inefficiencies Problems and Solutions at Energy Market Borders (2012)
FERC Docket No. EL03-35-002, Market Monitors’ Assessment of RTO Seams in the Midwest (2003)

(* Reports also include a summary of the history of seams management efforts)

Deep Dive: Five Sources of Inefficiencies Created by Market 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** is ineffective
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. **Loop flow management** inefficiencies through market-to-market coordinated flowgates (with shares of firm flow entitlements) under the existing JOAs
4. **Inefficient trading** across contract-path market seams and the need for intertie optimization
5. **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)

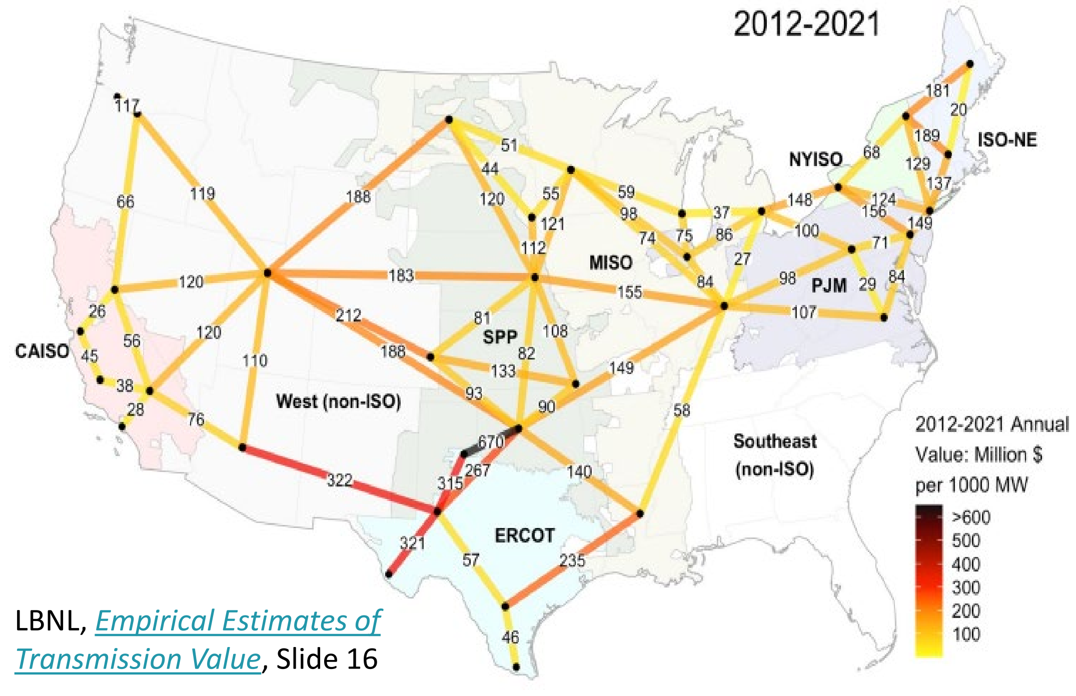
Topics discussed today

Background: RTO Seams, seams-related challenges and opportunities

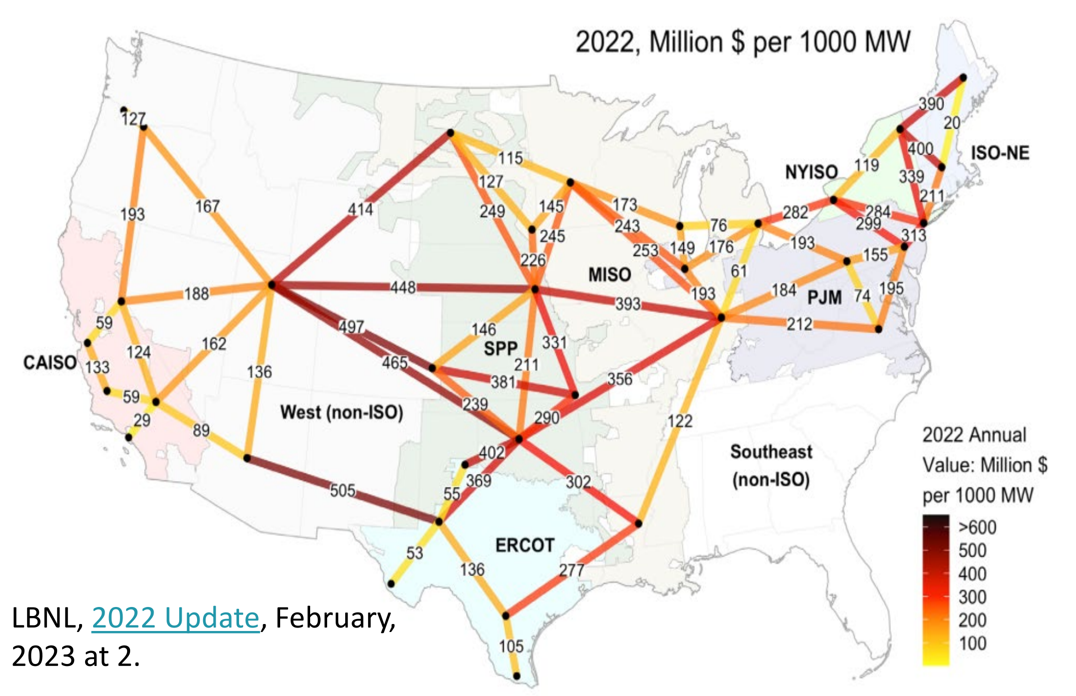
1. Interregional planning inefficiencies
2. Generator interconnection delays
3. Loop-flow-related challenges
4. Trading inefficiencies
5. Unrecognized resource adequacy value

Conclusions

LBNL Empirical Estimates: Total 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.

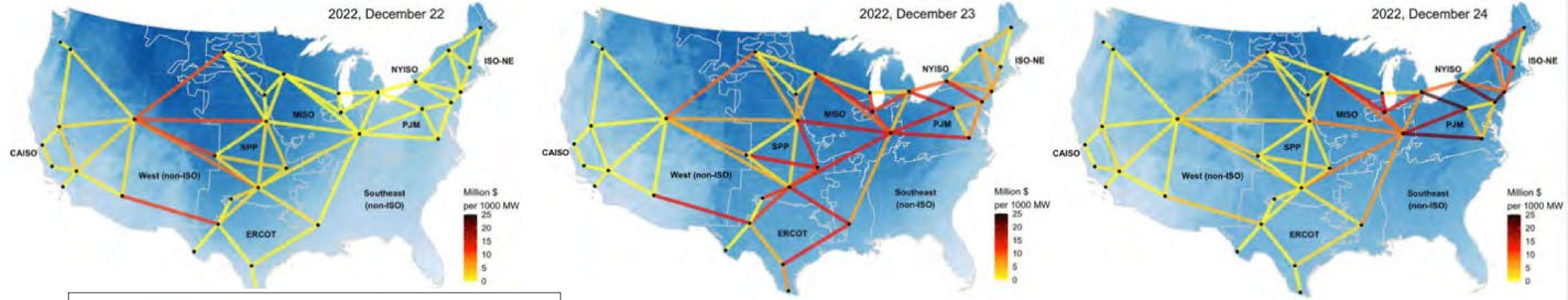
Methodology: Transmission value based on historical real-time price difference between regional nodes

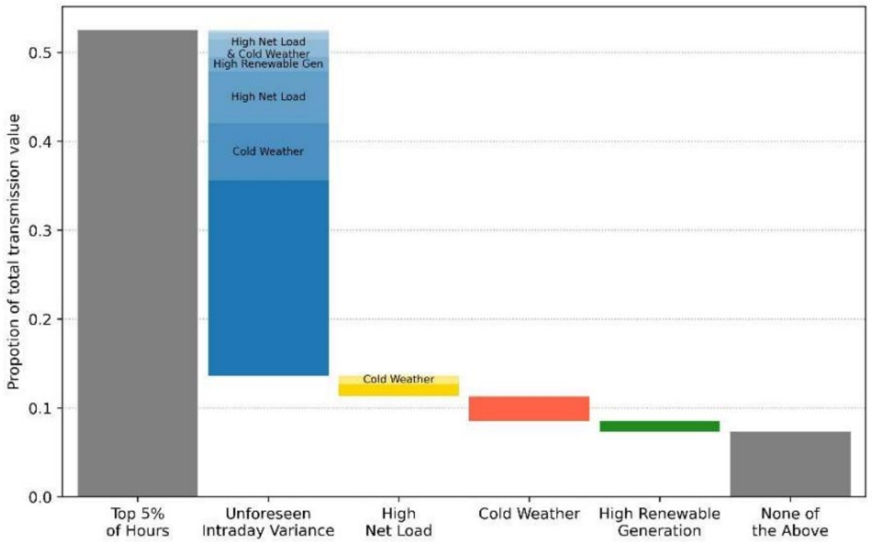
Study Findings:

- Interregional links have greater value than regional links
- **40-80% of transmission's congestion value is from 5% of hours due to extreme conditions,** 20-30% from top 1% of hours 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

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

The Resource Adequacy and Resilience Value of Interregional Transmission

In its ITCS, NERC found that existing interregional transmission has substantial resilience value. It further concluded that adding another 35 GW would be "prudent" solely for resilience value (before considering additional economic values)

Table ES.1: Recommended Prudent Additions Detail

Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
ERCOT	Winter Storm Uri (WY2021) and nine other events	135	18,926	14,100	Front Range (5,700) MISO-S (4,300) SPP-S (4,100)
MISO-E	WY2020 Heat Wave and two other events	58	5,715	3,000	MISO-W (2,000) PJM-W (1,000)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec (1,900)
SPP-S	Winter Storm Uri (WY2021)	34	4,137	3,700	Front Range (1,200) ERCOT (800) MISO-W (1,700)
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
California North	WY2022 Heat Wave	17	3,211	1,100	Wasatch Front (1,100)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec (400) Maritimes (300)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT (300) SERC-SE (300)
TOTAL				**35,000**	

Increasing Energy Deficiency Hours

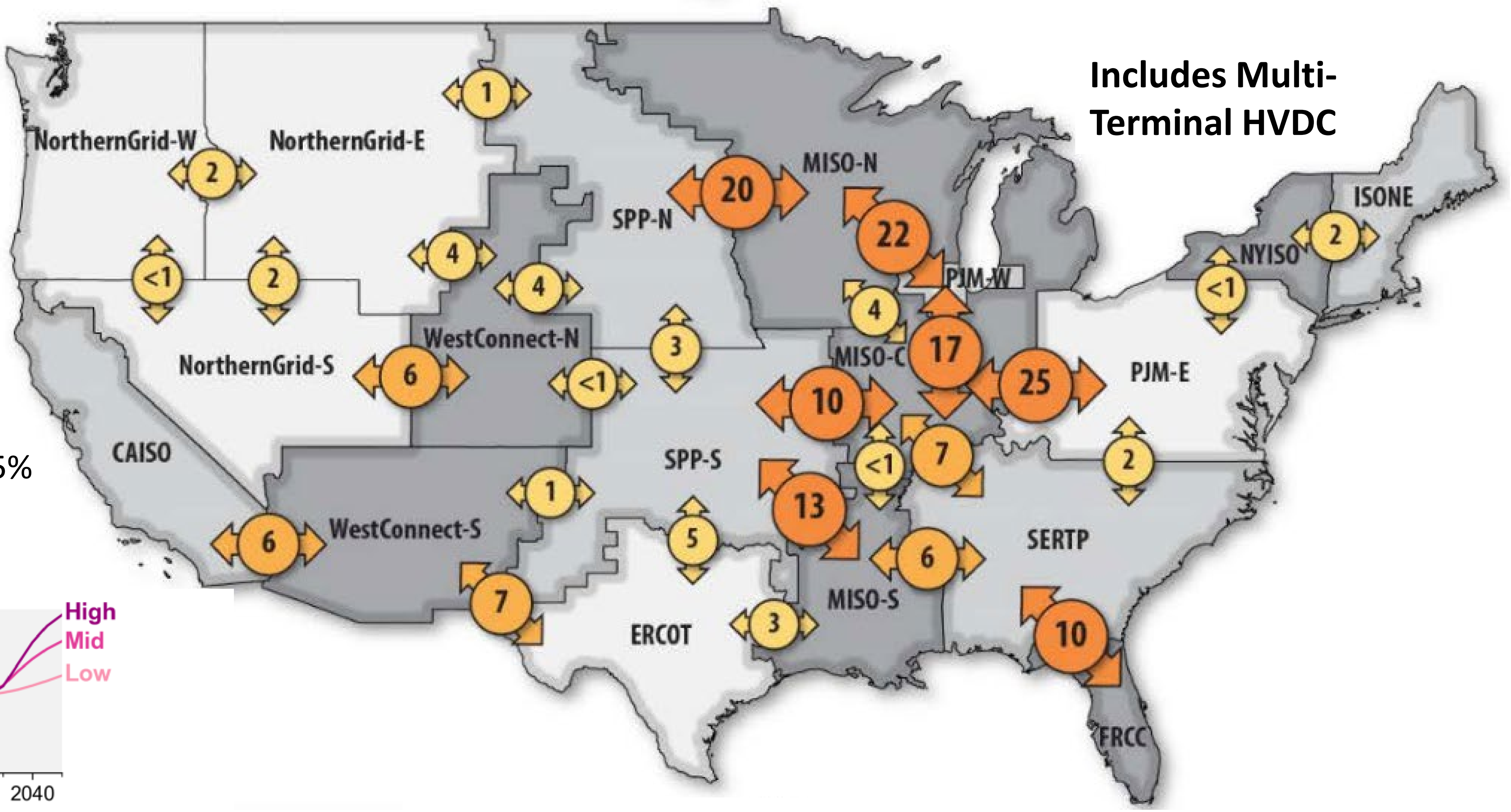
- This resource adequacy and resilience value of even "uncommitted" interregional transmission is recognized only by some RTOs/ISOs (e.g., NYISO and ISO-NE)
- Some RTOs (such as PJM) attribute very little resource adequacy value to existing interregional transmission and zero value to new interregional transmission
- None of the RTOs compensate the resource adequacy and resilience value of uncommitted interregional transmission provided by merchant lines (i.e., not paid through regulated transmission rates)
- Significant barriers also exist for capacity imports, where reserving firm transmission is no longer sufficient for capacity imports (such as in PJM)

Source: NERC Interregional Transfer Capability Study (ITCS), Parts 2 and 3 Report (2024)

DOE's 2024 National Transmission Planning Study (NTPS)

GW of "High-opportunity" interregional transmission expansion, beneficial by 2035

(Based on "central" case; beneficial in 75% of all scenarios evaluated)



Includes Multi-Terminal HVDC

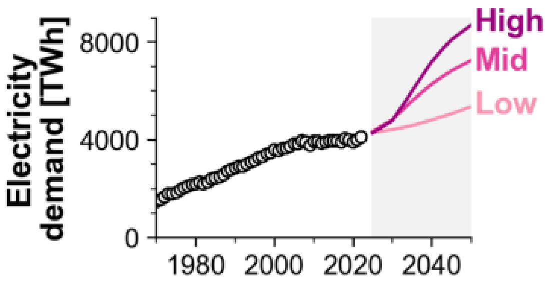


Figure 5. Annual demand assumptions for the contiguous United States

Historical demand shown is electricity sales to ultimate customers from EIA (2024b).

Source: DOE National Transmission Planning Study (Chapter 2, p. 47)

DOE's 2023 Transmission Needs Study

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

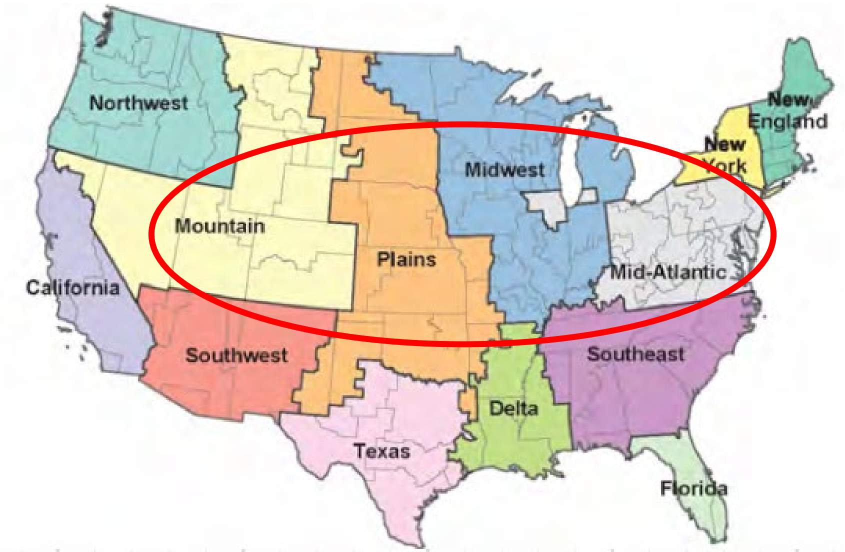


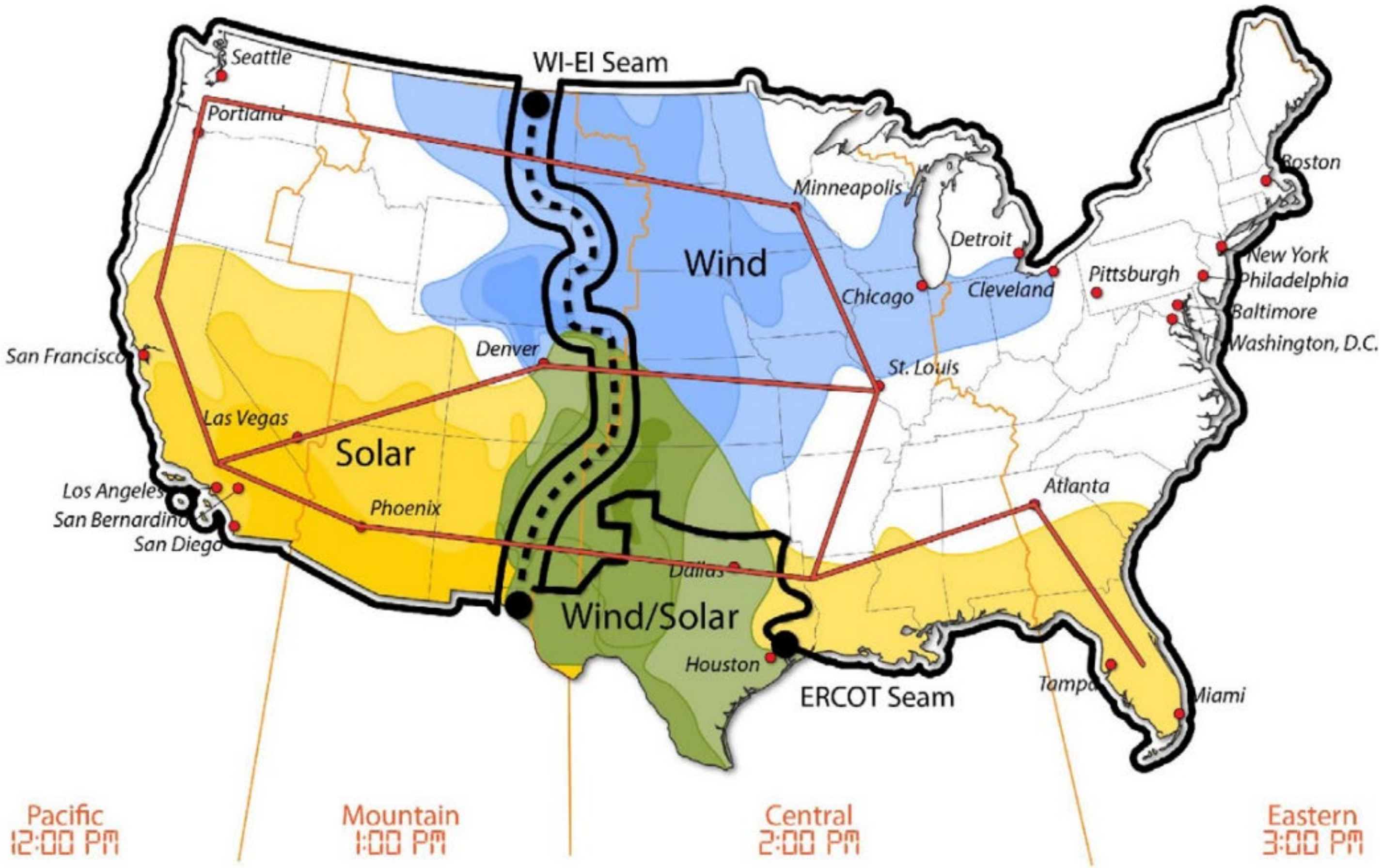
Table VI-4. Median regional transfer capacity results for each scenario group in 2030, 2035, and 2040. Both new transfer capacity in GW and percent growth from 2020 system are shown.

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

NREL's 2020 Interconnections Seams Study

Example: Macro Grid to Connect WECC, ERCOT and the Eastern Interconnection



Result: substantial net benefits for increasing the transfer capability between the interconnections

- Four different "designs" studied:
  1. Only upgrade AC systems (not across seam)
  2a. Upgrades to DC ties plus AC lines
  2b. Point-to-point HVDC transmission lines
  3. Macro Grid (shown)
- Depending on scenario and design, estimated benefit-cost ratios range from 1.4 to 2.9
- Study did not consider certain benefits, such as resilience to extreme events

Source: NREL, Interconnections Seams Study, October 2020.

Limitations of National Studies

Although existing many studies demonstrate the benefits of transmission expansion, they have not been successful motivating actual transmission project developments. The reasons include some or all of the following:

- Some studies **analyze aspirational targets or scenarios that do not reflect the actual policies and mandates** applicable for the next 10-15 years
  - This makes it difficult demonstrate a compelling “need” to policy makers, regulators, and permitting agencies
- The studies are **not transmission planning studies**: they often do not identify specific transmission projects and do not connect with RTO planning processes and needs identification
- 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 broad support and develop feasible cost allocations
  - 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, reduction in electricity prices, and shifts in the locations of clean-energy investment
- Most studies do not address the many barriers to planning processes and to the permitting/development of specific interregional transmission projects

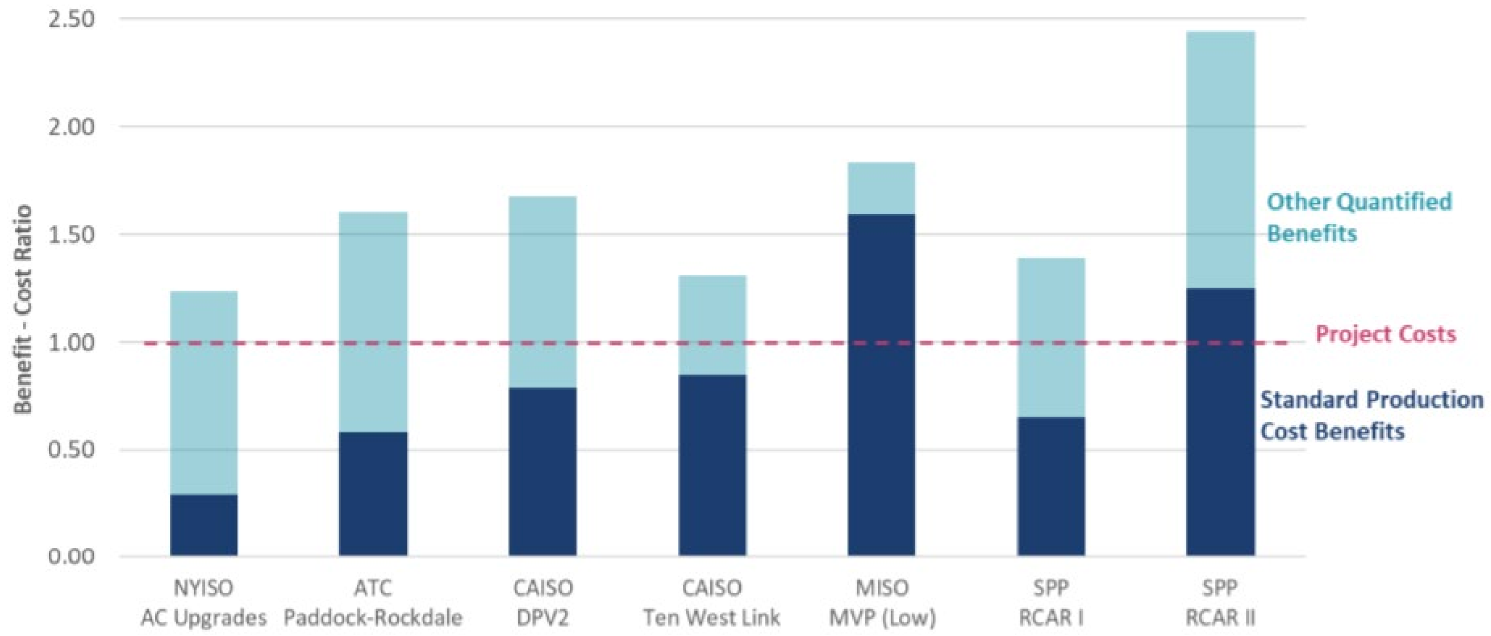
At the same time, RTOs’ existing interregional planning processes has been mostly ineffective, yielding only a few small “economic efficiency” projects (other than JTIQ, discussed later)

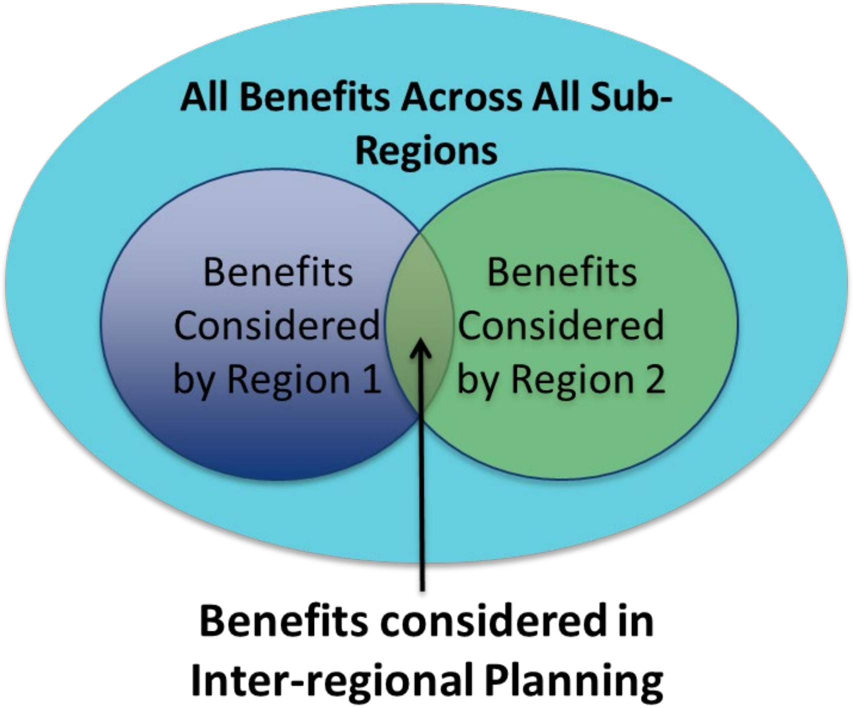
Problem: understated quantifications of transmission benefits

Order 1920 will help expand benefit metrics (i.e., cost savings and reliability enhancements) of transmission, but the main metrics used (incl. Production Cost Savings) tend to understate 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





Sources: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs
A Roadmap to Improved Interregional Transmission Planning
Transmission Benefits and Opportunities for Improved Planning under Order 1920

Significant Barriers to Interregional Transmission

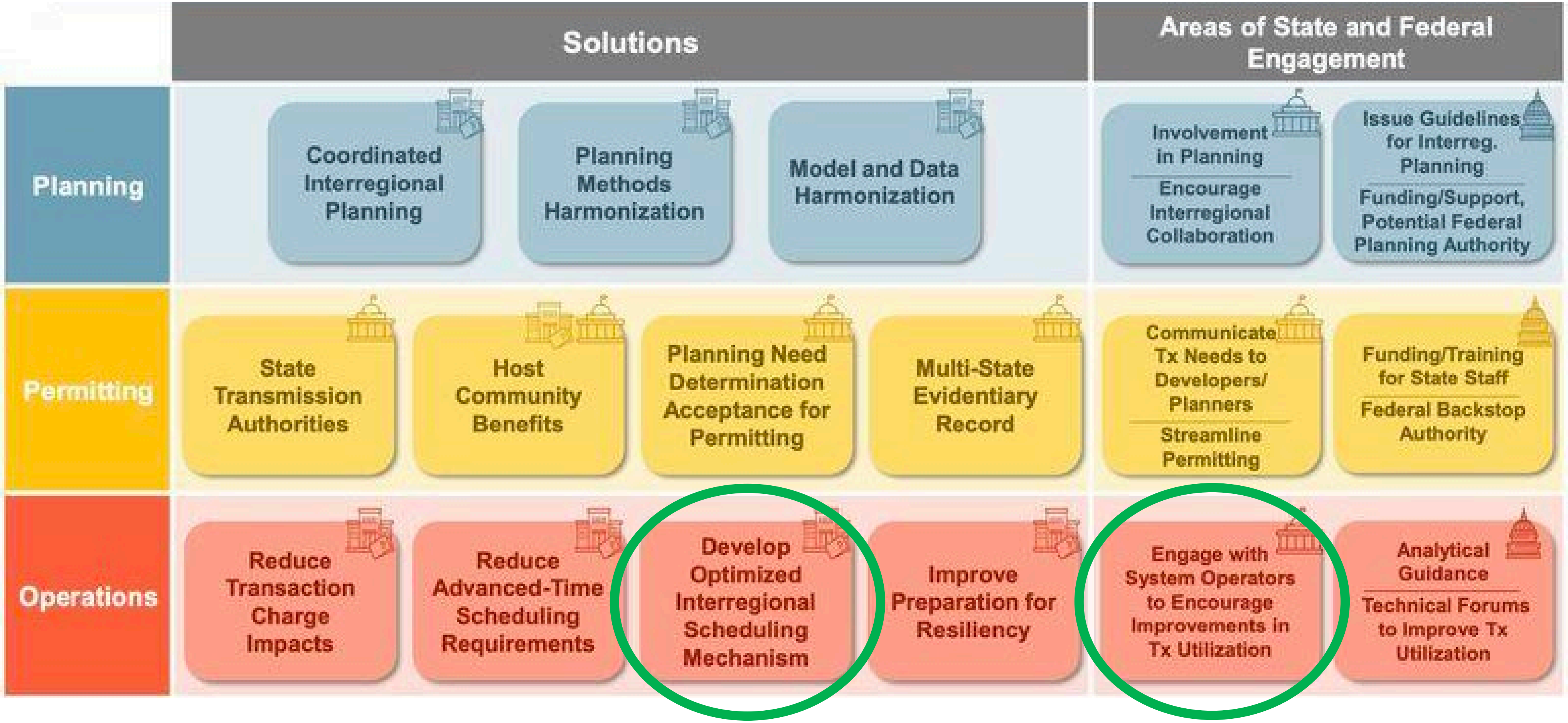
A. Leadership, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policy makers to prioritize interregional planning 2. Limited trust amongst states, RTOs, utilities, & customers 3. Limited understanding of transmission issues, benefits & proposed solutions 4. Misaligned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

Source: The Brattle Group. 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.

NARUC Report: Collaborative Enhancements to Unlock Interregional Transmission (June 2024)

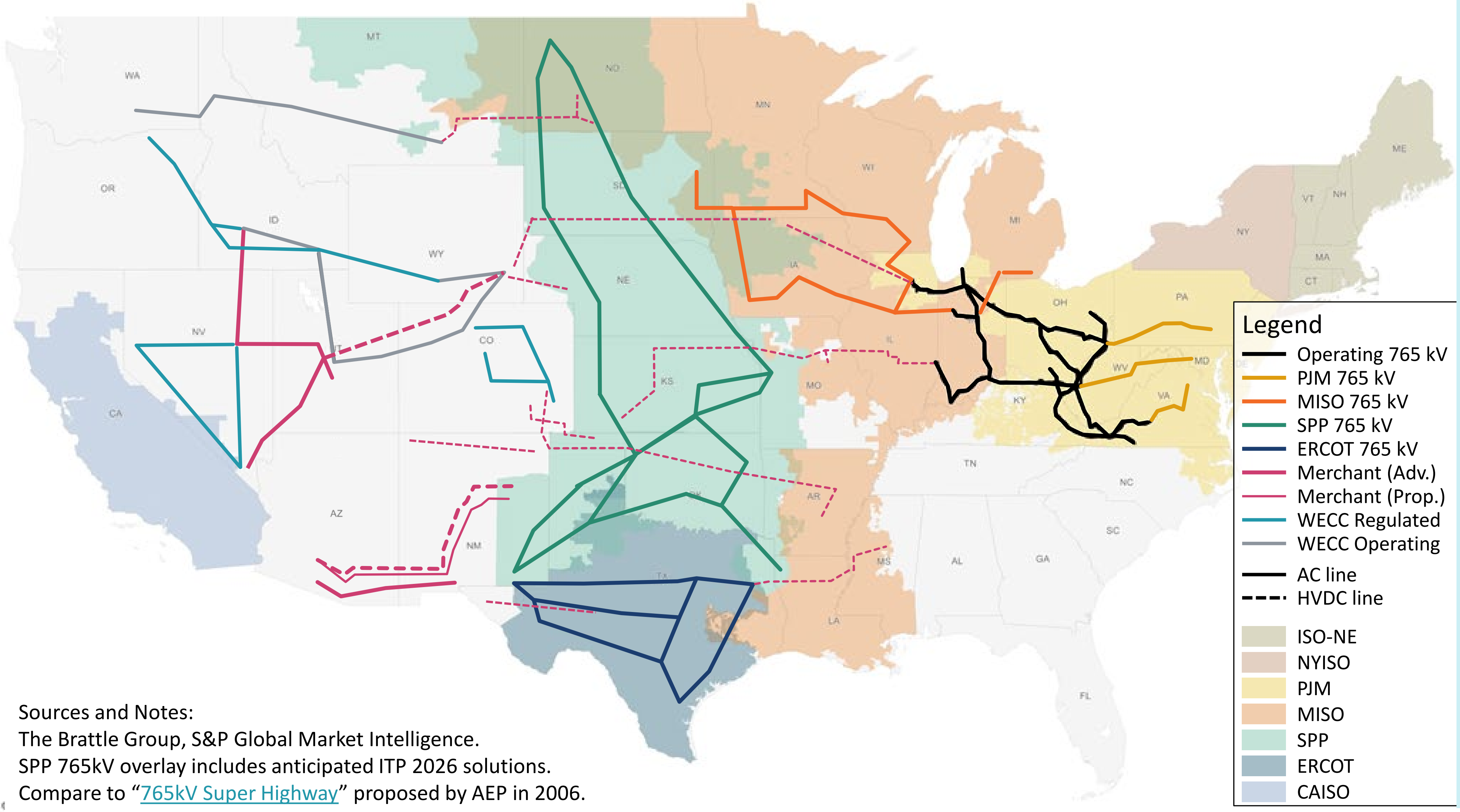
NARUC
National Association of Regulatory Utility Commissioners

Recommends reforms improve planning, permitting, and operational utilization of interregional transmission, including intertie optimization:



Source: https://pubs.naruc.org/pub/BACDBB9D-02BF-0090-0109-B51B36B74439

Interregional planning and cost allocation is needed to fill in the gaps



Sources and Notes:
The Brattle Group, S&P Global Market Intelligence.
SPP 765kV overlay includes anticipated ITP 2026 solutions.
Compare to "765kV Super Highway" proposed by AEP in 2006.

The 765 kV systems planned by PJM, MISO, SPP, and ERCOT are adjacent to each other!

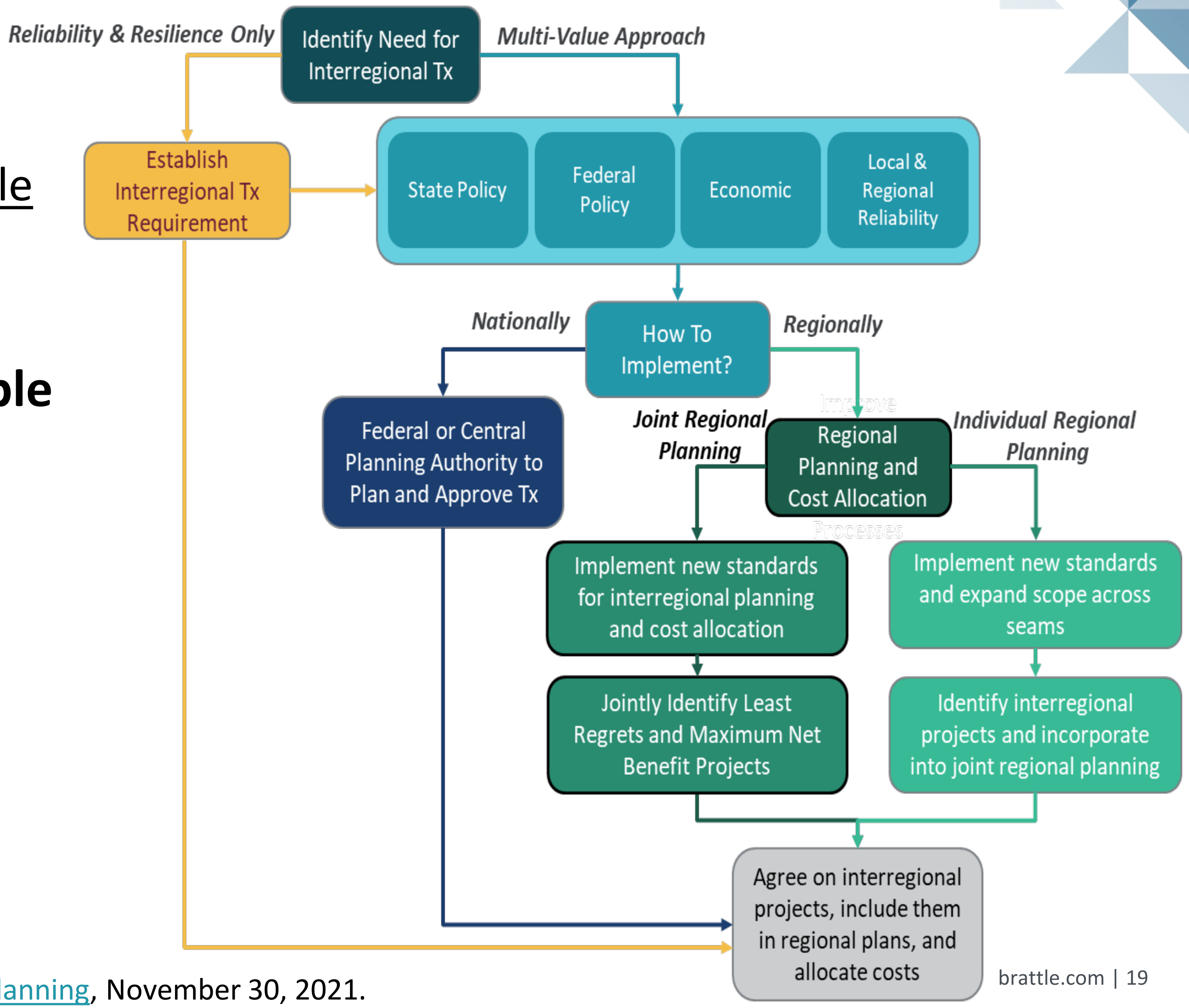
- If planned to be connected, they would create an interregional Macro Grid
- Could also be integrated with HVDC lines, including into ERCOT and WECC
- Cost allocation disputes already exist (MISO-PJM)

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.

Order 1920's enhances "Interregional Transmission Coordination"

As FERC's Explainer states: "Order No. 1920 requires transmission providers in neighboring transmission planning regions to modify their existing **interregional transmission coordination procedures** to align with long-term regional transmission planning reforms. Order No. 1920 established the following requirements to adapt existing procedures with this requirement.

1. Require transmission providers to share information regarding long-term transmission needs and **identify and jointly evaluate interregional transmission facilities** to address those needs
2. **Allow entities to propose** interregional transmission facilities as more efficient or cost-effective solutions to long-term transmission needs

Transmission providers are mandated to make the following information publicly available through their website or e-mail list to **enhance transparency and information sharing**.

1. Long-term transmission needs discussed in interregional transmission coordination meetings
2. Interregional transmission facilities proposed or identified as part of long-term regional transmission planning
3. Details such as voltage level, estimated cost, and estimated in-service date of proposed interregional transmission facilities
4. Results of cost-benefit evaluations for such interregional transmission facilities, including overall benefits and region-specific benefits
5. Selection of interregional transmission facilities to meet long-term transmission needs, if any

These reforms aim to ensure that identified long-term transmission needs are considered in interregional coordination and cost allocation processes, thereby promoting fair rates."

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 to more fully capture benefits:
  - Improve representation of neighboring regions in model footprint to capture diversity
  - Capture impacts of challenging conditions 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 benefit metrics of neighboring regions in economic analyses
  - Recognize the full resource adequacy value 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 interregional solutions 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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Conclusions

Seams create generator interconnection delays and cost uncertainty

"Affected system" impact studies are sequential, time-intensive analyses by neighboring grids, often resulting in uncertain timelines and increased costs

- These Affected System Studies (AFS) are required when new generation impacts adjacent transmission systems, forcing developers to sign separate agreements, undergo, and fund extra, uncoordinated studies and associated transmission upgrades
  - Few standardized procedures or deadlines cause affected system studies to lag behind the host system's generator interconnection studies and delaying the entire interconnection process
  - Often, an affected system study cannot begin until the host system completes its initial study phases, adding months (or years) to the timeline
  - If network upgrades are identified by the neighboring region, the projects may require a the host region to redo the entire study process
  - Causes additional uncertainty about costs and timelines (as developers must deal with multiple, separate transmission providers and their different study processes)
- FERC Order No. 2023 introduced reforms to streamline the process, including standardizing agreements for affected system studies and deadlines (AFS need to be completed within 150 days of initiation)
  - Example: MISO and SPP developed JOA revisions to (1) facilitate a more efficient AFS to comply with Order 2023 and, additionally, (2) implement a Joint Targeted Interconnection Queue (JTIQ) Study process (link)

MISO-SPP JTIQ: Faster, lower-cost generator interconnection solutions

MISO's and SPP's Joint Targeted Interconnection Queue (JTIQ) Study shows that proactively studying a larger interregional set of generator interconnection requests offers substantial cost savings

- Goal: Identify more comprehensive, cost-effective and efficient interregional network upgrades than could be found through the RTO's individual sequential interconnection queue and affected system coordination processes
  - Pooled GI requests for 5 (and 10) years in both regions near seam
- Result: Seven projects, **$1.65 billion JTIQ Portfolio** expected to fully address the transmission needs along the MISO-SPP seam previously identified in MISO and SPP individual generation interconnection studies
  - Able to quickly allow for 9 GW of existing generator interconnection requests and enable an additional 20 GW of projects near the SPP-MISO seam
  - Additionally yields estimated $1 billion in production cost savings ($724 million in MISO and $247 million in SPP) due to congestion relief
- Lower JTIQ generator interconnection costs: **$58/kW** with 100% participant funding; and **$28/kW** if production cost savings to regional loads are netted
  - **Less than half of SPP's and MISO's individual GI costs of $100-130/kW!**

See MISO-SPP Joint Targeted Interconnection Queue Study, March 2022.
Tsuchida, Proactive Planning for Generation Interconnection A Case Study of SPP and MISO (August 17, 2022) at 9

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The RTOs' loop-flow management

Under their JOAs, SPP, MISO, and PJM manage loop flows through a Congestion Management Process (CMP) and the Interregional Coordination Process (ICP, also commonly referred to as "market-to-market coordination" or M2M)

- Based on identifying Reciprocal Coordinated Flowgates (RCFs), which are frequent transmission constraints where one region's loop flows significantly impacts the other region's RCF
- CMP defines each party's rights to RCFs based on Firm Flow Entitlements (FFEs) based on 2004 freeze date
- Uses curtailments (transmission loading relief or TLR) for flows from non-market regions

Between market regions, the ICP/M2M process builds on the CMP (see OMS-RSC M2M Study)

- Market regions jointly dispatch their energy markets to manage congestion on hundreds of M2M RCFs
- Utilizes real-time data exchange and market-based congestion management on M2M-managed RCFs
- Applies to market-internal transactions and transactions between markets that create loop flows
- "Monitoring" RTO notifies neighbor of constraint, requested relief, and shadow price; neighbor then tries to offer relief (up to that shadow price) by activating the constraint in its congestion management system
- RTOs compensate each other if one RTO's utilization of the flow gate exceeds its FFE (i.e., it uses the other region's FFE) on M2M constraints

Inefficiencies of RTOs' loop-flow management

Market monitors and market participants have pointed out M2M inefficiencies

- Failures in converging shadow prices, differences in transmission modeling, and limitations in the testing criteria for M2M constraints leads to inaccurate congestion pricing, excessive "JOA uplift" charges, inefficient market operations, and (at times) worsened power flows
  - Limited shadow price convergence: Monitoring RTO (MRTO) communicates shadow price and requests relief to limit flows to FFE; non-monitoring RTO (NMRTO) re-dispatches its generation to provide requested relief at a cost up to the MRTO's stated shadow price. If NMRTO shadow prices do not converge, the MRTO's requested relief was too high or too low. (see OMS-RSC M2M Study)
  - Inconsistencies in transmission models used by the RTOs (i.e., how one RTO models its neighbor vs. how the neighbor models itself) can lead to incorrect congestion models and inefficient dispatch
  - 5% shift factor and 25%-35% market flow thresholds used to determine if a constraint should be managed through M2M can lead to ineffective coordination
  - Lag between a MRTO's request and the NMRTO's re-dispatch creates inefficiencies and can lead to real-time power oscillation and price volatility
- Market monitors have recommended enhancing the M2M process, including tightening the coordination of constraint management and reducing the use of "generator shift factor" cutoffs, which limit the ability of one RTO to relieve constraints on another's system

Case Study: Recent MISO-SPP dispute over ND flowgate

MISO and SPP disagreement over an SPP M2M constraint in North Dakota and $38 million M2M congestion charges payable by MISO:

- 200-MW cryptocurrency data center in SPP's North Dakota footprint (Charlie Creek to Watford City line defining the Northwest North Dakota Load Pocket) caused substantial congestion
  - MISO and its member Montana-Dakota Utilities (MDU) are disputing the $38 million charges as "unnecessary, unjust and unreasonable" market-to-market (M2M) congestion charges
  - MISO argues M2M flowgate designation and charges are inappropriate because (1) the congestion is local to SPP and not regional and (2) that MISO is unable to relieve congestion on that flowgate
- SPP maintains it is following their JOA and that MISO is responsible for compensating SPP

FERC agreed with SPP:

- Found that the Charlie Creek Flowgate passed the RTOs' flowgate eligibility studies
- FERC rejected MISO's request for rehearing
- MISO has now appealed the FERC orders in court (*ER24-1586, et al*)

RTO interface definitions and pricing

Related to M2M coordination is how RTOs define and price the "interface" between them, over which bilateral trades between them are scheduled and settled.

- Market monitors for PJM, MISO, and SPP have recommended modifying interface definition and pricing
  - A single "interface" is defined between neighboring RTOs over which bilateral contract path transactions can be scheduled using "point-to-point" transmission service
  - The concept of a single "point-to-point contract path" between large regions is inconsistent with how transmission works physically, leading to inefficient transmission utilization, generation dispatch, and pricing
- Key recommendations include:
  - Adopting more accurate, marginal-based interface pricing
  - Improving M2M coordination to avoid double counting congestion
    - Only the Monitoring RTO (the one responsible for the constraint) should include the congestion associated with M2M constraints in its interface prices
  - Updating the weighting of interface components
  - Updating how external Balancing Authorities (BAs) are mapped to RTOs' interface pricing points
  - Replacing the current interface definition with more accurate pricing that reflects the actual seam
  - Improve real-time interchange between the RTOs to reduce volatility and better reflect price differences (discussed next)

Topics discussed today

Background: RTO Seams, seams-related challenges and opportunities

1. Planning inefficiencies
2. Generator interconnection delays
3. Loop-flow-related challenges
4. **Trading inefficiencies**
5. Unrecognized resource adequacy value

Conclusions

Interregional transmission is poorly utilized by bilateral trades

2023 PJM State of the Market Report: power flows the wrong way 40-50% of the year!

- Price differences across the MISO-PJM seam exceeded $5/MWh during 3,331 hours; yet during 1,519 (43%) 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 $5/MWh during 4,218 hours, with inconsistent market flows during 1,641 (50%) of these hours

Potomac Economics previously observed similar 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 intertie optimization offers the only effective solution

- **Day-ahead**: average (absolute) value of 2023 PJM-NYISO price difference of $4.62/MWh with price differences changing signs 2.9 times per day. With absolute PJM-MISO difference = $3.72/MWh, changing sign 3.8 times/day
- **Real-time**: average (absolute) PJM-NYISO price difference of $11.04/MWh with sign changing sign 49 times each day. With absolute PJM-MISO difference = $10.21/MWh, changing sign 61 times each day

The need for intertie optimization

The Need for Intertie Optimization, prepared for ACORE, Advanced Power Alliance, Grid United, Invenergy, MAREC, and NRDC, October 2023

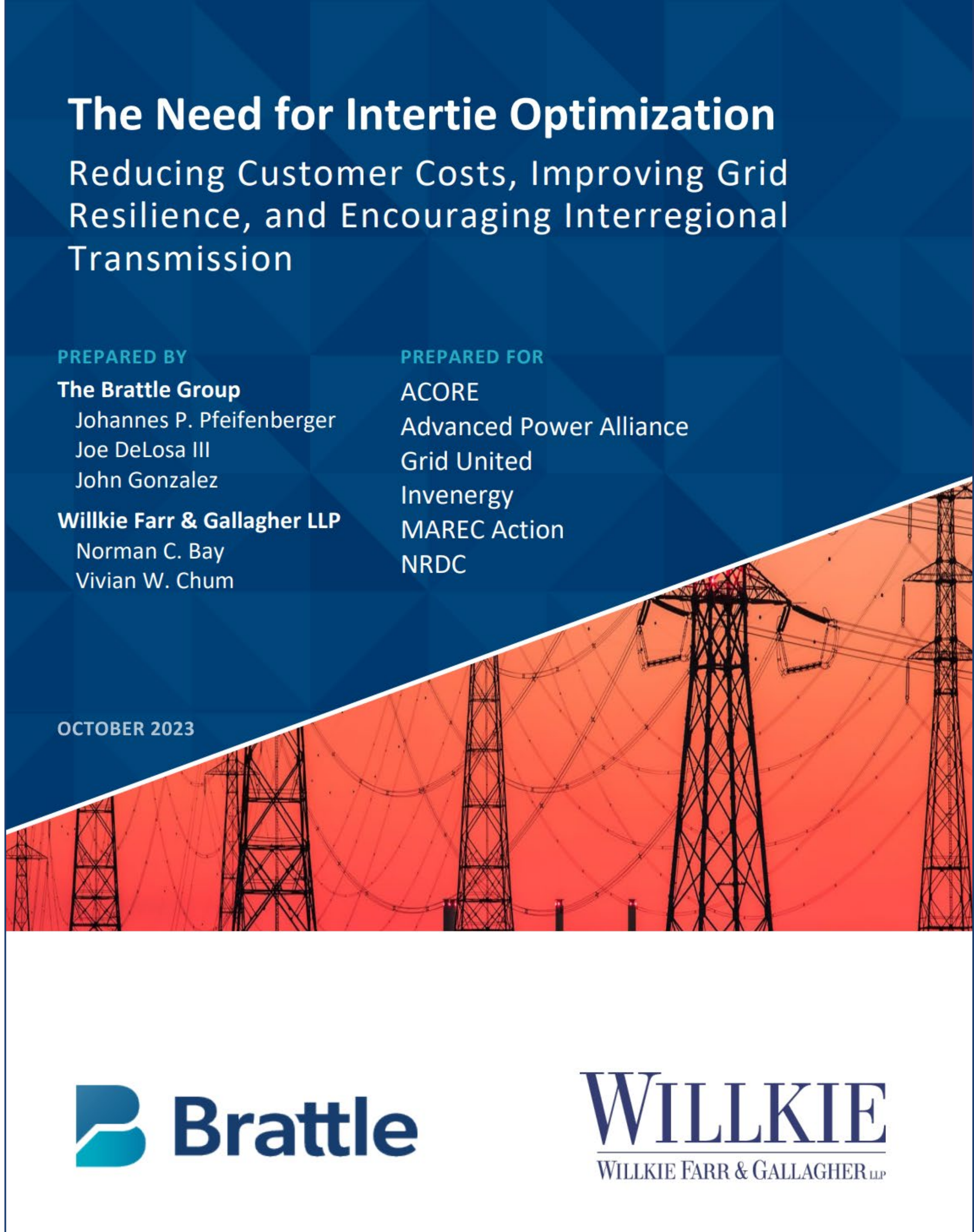
Intertie Optimization FAQs and Implementation Principles, February 2024

Intertie Optimization: Efficient Use of Interregional Transmission (Update), presented to OPSI, April 12, 2024

Market Benefits and Seams: Options and Implications, presented to CREPC-WIRAB, April 24, 2024.

Intertie Optimization: Achieving Efficient Use of Interregional Transmission, IEEE PES, Energy Policy Forum, April 16, 2025.

Various State of Market, LBNL, and NREL reports (as cited in the above)



The Need for Intertie Optimization

Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission

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OCTOBER 2023

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Intertie Optimization: More efficiently trade across market seams

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

- NYISO, ISO-NE, and Potomac Economics 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 recommending intertie optimization
  - PJM's IMM has recommended intertie optimization in every year since 2014; NREL and NARUC reports recommend intertie optimization as well
- 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; FERC approved; WEIM reduced costs by over $5 billion since inception

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)

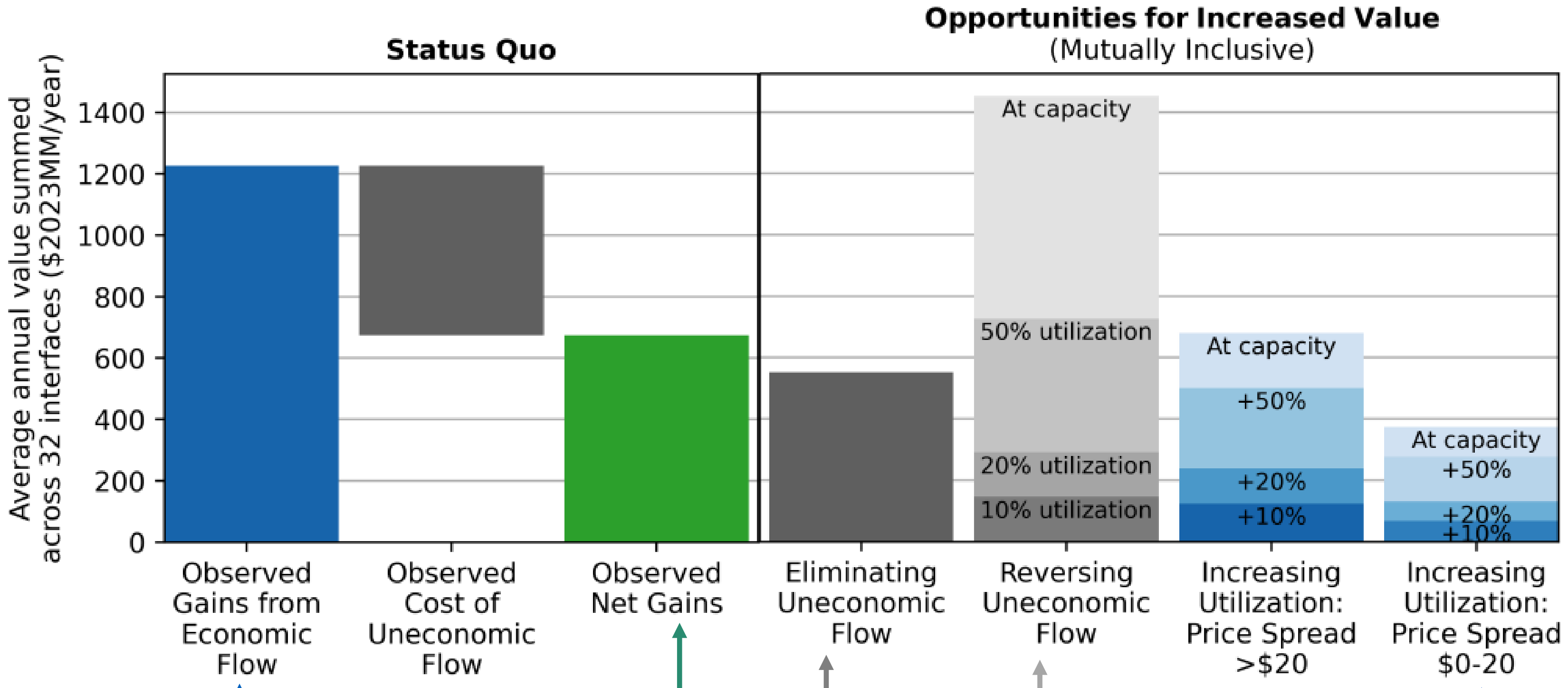
For merchant transmission lines, intertie optimization revenues would need to accrue to either the transmission owner or its subscribers

  - See CAISO Subscriber PTO proposal

Estimated national inefficiencies and potential cost savings

NREL Paper: Interregional Electricity Transmission in the United States: Realized Savings and Opportunities for Increased Value, 2014-2023 (April 2025)

- Analyzed the benefits & efficiency of energy trades across 32 interties between US market areas for last decade



Intertie optimization could yield up to $3b/year in additional interregional benefits using the existing interties (before adjusting for price convergence, but not counting intra-hour benefits)

More fully utilize available capacity (in prevailing direction): up to $1b/yr added

$1.2b in annual value

Offset by over $500m in uneconomic trades

Yields close to $700m in annual net benefits

Reverse flow when beneficial: up to $1.4b/yr in added value

Eliminate uneconomic trades: Over $500m/yr in added value

Experience with intertie optimization: WECC and Europe

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

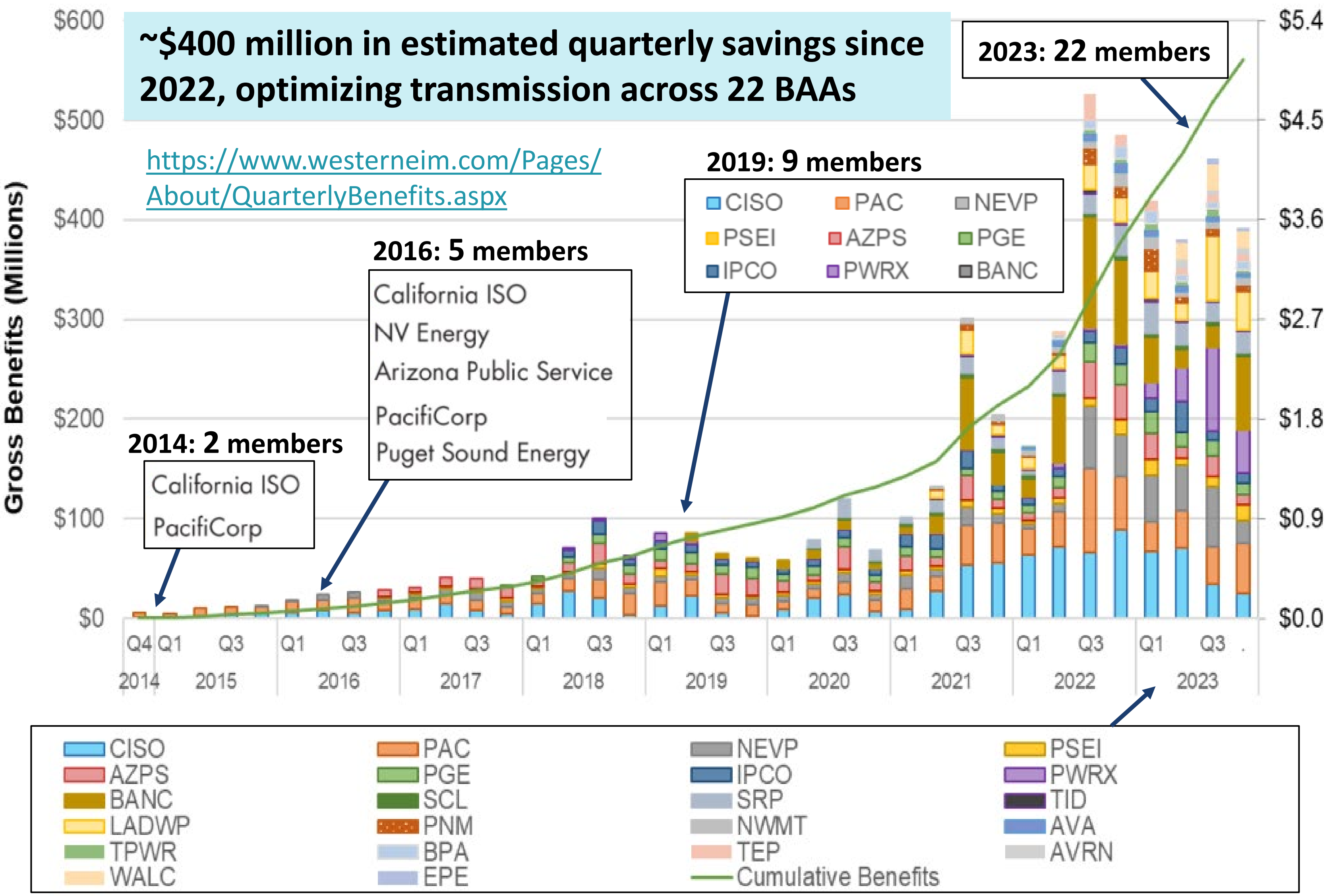
- Depancaked WEIM and WEIS transactions are scheduled on a 15-minute/ 5-minute basis after all bilateral trading has closed (approximately 20 minutes before each real-time operating period), using transmission that remains available and otherwise would go unutilized
- $5 billion in savings accrued through 2023 to the neighboring BAAs and other entities that contribute available transmission
- Real-time optimization of interregional transmission now expanded to day-ahead markets (EDAM)
- CAISO's Subscriber PTO framework: integrate unutilized capacity on merchant transmission lines into regional and interregional DA and RT energy markets

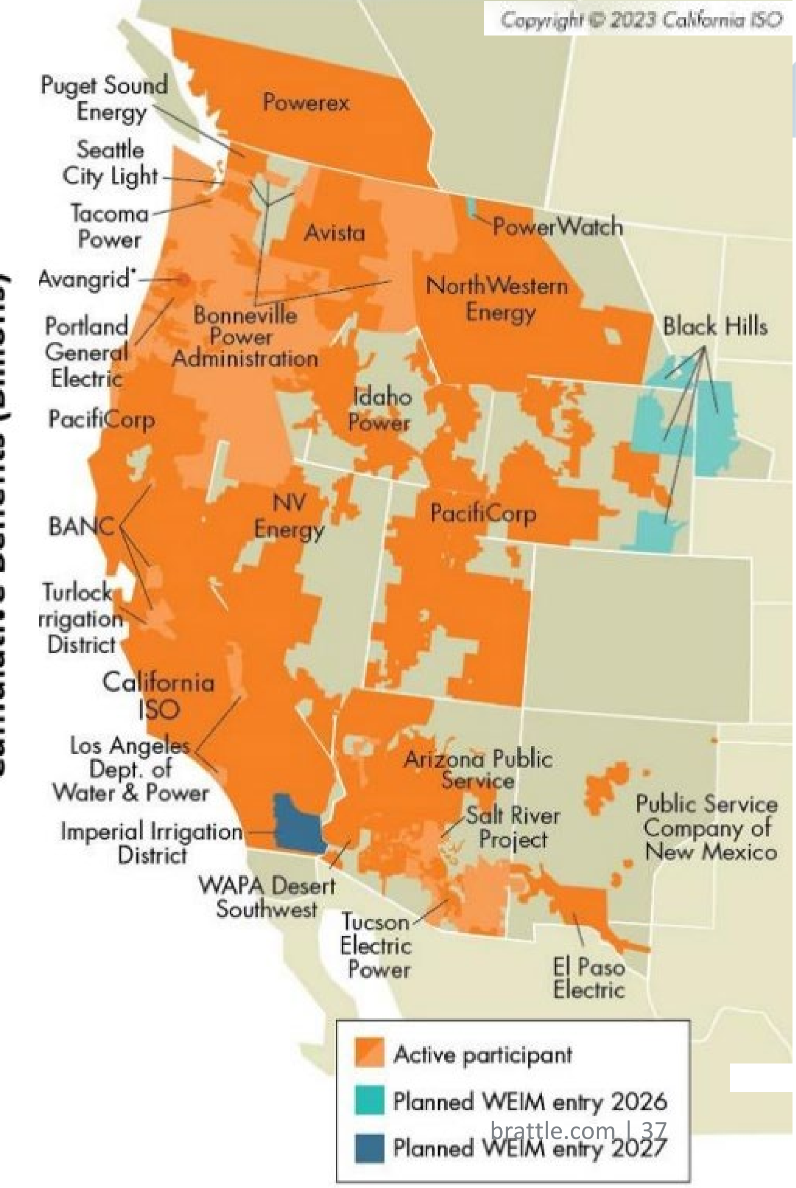
Flow-based "Market Coupling" in central and western Europe (for transmission left available after bilateral day-ahead and intra-day trading closes) is currently expanded to Scandinavia

By 2025, WEIM achieved $8 billion savings from transmission seam optimization across multiple BAs in RT energy markets

~$400 million in estimated quarterly savings since 2022, optimizing transmission across 22 BAAs

https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx





Intertie Optimization: Avoids the inefficiencies of CTS

Coordinated Transaction Scheduling (CTS)

- 75+min prescheduled 15-min transactions, based on forecasts, which often results in uneconomic trades
- Based on CTS bids by traders, who need to reserve transmission (at a cost)
- Transmission charges reduce CTS efficiency
- If transmission charges are eliminated, traders capture value of transactions (free rides)
- Experience:
  - Low transaction volume due to costs and risk of inefficient trades;
  - Has not been able to improve inefficient use of interregional transmission

Intertie Optimization

- Optimized in real time every 5 min, greatly reducing the frequency of uneconomic trades
- Optimized by RTOs using transmission that remains available after bilateral markets have closed
- Hurdle-free optimization increases market efficiency
- Value of transactions shared by RTOs (i.e., their transmission owners and, ultimately, customers)
- Experience:
  - High transaction volume with substantial benefits to participating BAAs (e.g., Western EIM)
  - Can greatly reduce inefficient use of interregional transmission (e.g., European "market coupling")

Bottom Line: CTS is not working – not for Traders, not for RTOs, not for TOs, and not for Customers

See also: Frequently Asked Questions

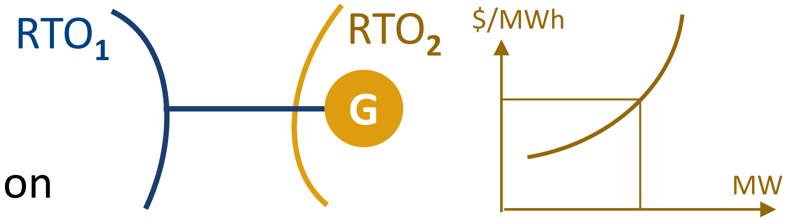
Intertie Optimization: Implementation options

How would RTOs/ISOs determine and schedule optimal intertie transactions?

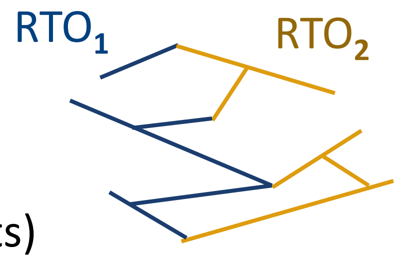
The RTOs would use their existing market optimization SCED engines to optimize intertie schedules subject to available intertie capabilities after all bilateral transactions are closed

- As the PJM IMM explains, this 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" (2023 SOM Report at 478)

1. **Contract-path option**: treat the contract path across the interface like a single line with a generator (representing the neighboring region) dispatched through SCED.
   - The neighboring region would provide generation supply curve (incremental/decremental cost of importing more or less) for RT intervals
   - Simplest, will increase efficiency, but not optimally use full physical transmission



2. **Flow-based option:** represent interface physically with limiting flow gates
   - The neighboring region provides binding flow gates and marginal generators with shift factors on these flow gates (ISO-NE's 2014 IEEE "Marginal Equivalent" proposal)
   - Will use full physical capability (ISO-NE simulations achieve 99% of full optimization)



3. **Combined SCED option:** used full, multi-regional SCED (similar to Western imbalance markets)
   - Assures full optimization but likely impractical for existing market-based regions

See also: Frequently Asked Questions

Promising Initiative: SPP’s inter-market optimization framework

- SPP has been exploring Inter-Market Optimization (IMO) to improve the efficiency of transfers between SPP and its neighbors
  - On October 16, 2024, SPP’s Strategic Planning Committee (SPC) endorsed that IMO be prioritized within the “Optimized Seams” objectives of SPP’s strategic planning roadmap
- SPP’s IMO Analysis Paper (2025) concludes that a significant opportunity exists for optimizing interchanges on the SPP-MISO seam
- SPP’s next steps:
  - Develop (in 2026) a modular, expandable IMO design applicable to SPP and any physically adjacent market
  - Start with IMO for SPP’s Western RTO and Markets+
  - Engage with MISO to evaluate IMO opportunities and potential value

Source: SPP Documents & Filings – SPC Meeting Materials, Oct 8, 2024; 2026-02-02 joint briefing agenda materials

FERC Has the authority to implement intertie optimization

Co-authors (Norman Bay and Vivan Chum) concluded in our report:

- 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

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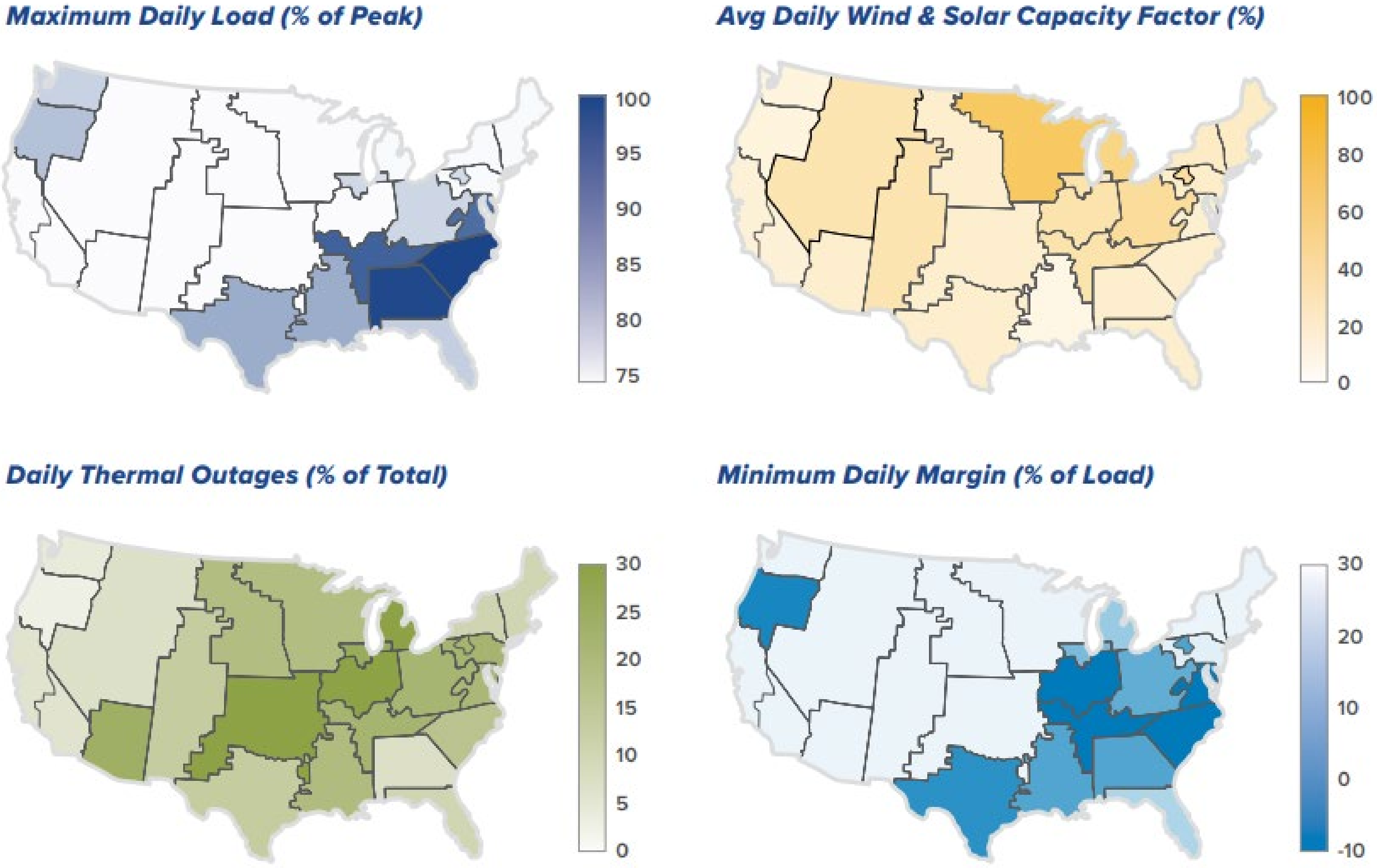
Conclusions

Resource adequacy value of interregional transmission

<u>Concept</u>: if a robust grid is larger than most weather systems, individual regions can rely on (non-firm) imports from others' generating reserves, reducing everyone's resource adequacy risks, costs, and reserve margins

<u>Example</u>: Load diversity and resource diversity of neighboring regions on **December 22, 2022 (during Winter Storm Elliot)**



Source: Brooks et al., Resource Adequacy Value of Interregional Transmission, (2025)

SPP FERNS: RA value of non-firm trade with neighboring regions

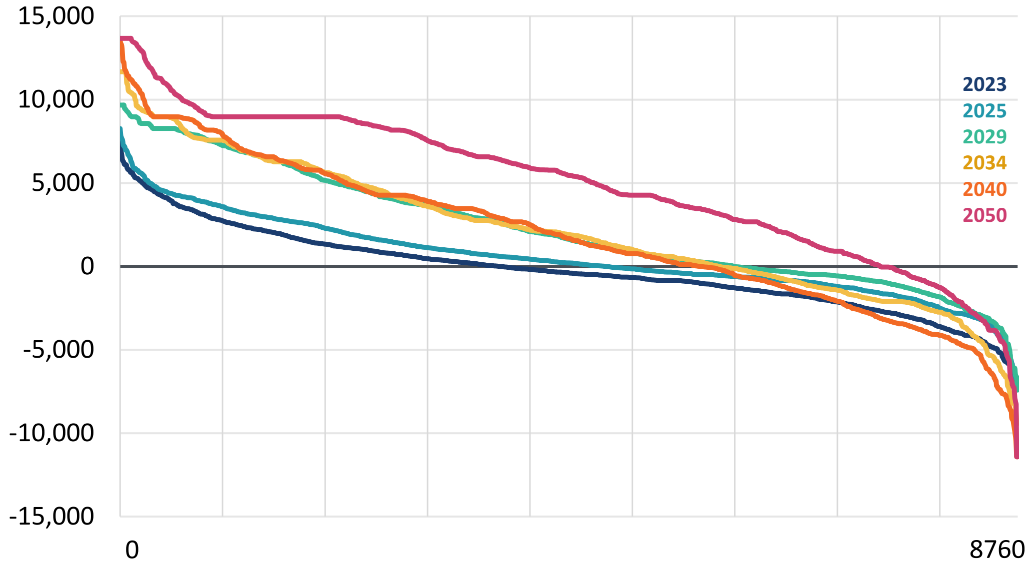
Simulations from SPP FERNS report show that SPP will increasingly trade with neighboring regions through interties with MISO, ERCOT, and the West

- Although interties with neighboring regions are not assumed to contribute to SPP resource adequacy requirements, SPP can often import energy to serve load during scarcity periods
- We quantified the implied resource adequacy ("proxy ELCC") value based on the (non-firm) energy imports into SPP over external interfaces during the 100 highest resource adequacy risk hours

Note: Charts show results for "Scenario B2" reflecting high renewable generation shares (reaching 90% by 2050, up from 46% today) at moderate load growth

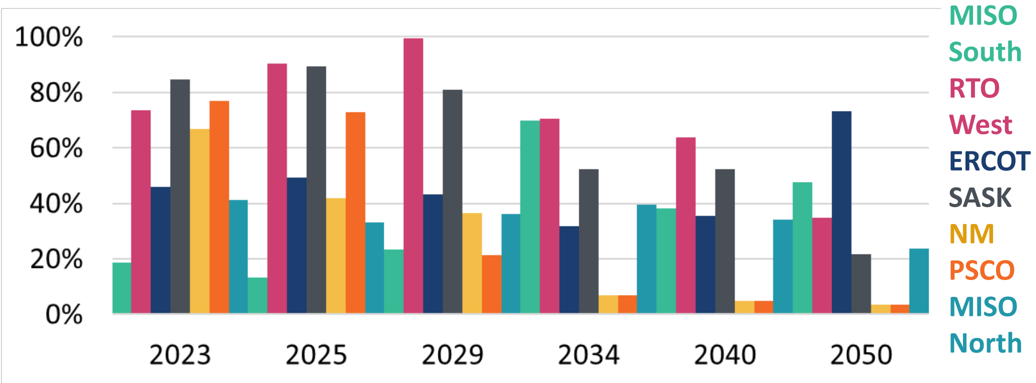
SPP Net Imports and Exports across all interties (MW)

(Positive = net flow out of SPP; Negative = net flow into SPP)



Note: Net imports shown across interfaces between SPP and all neighboring regions

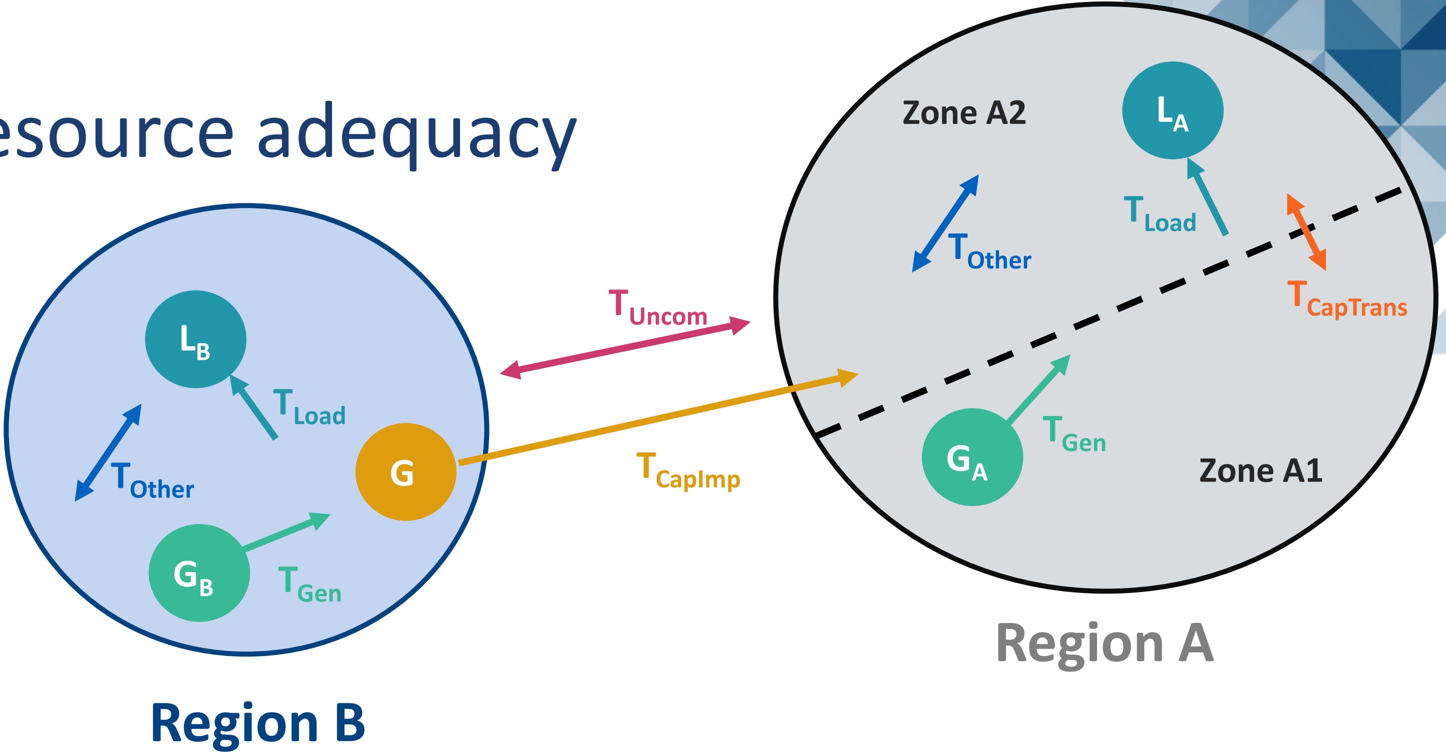
Implied "Proxy ELCCs" of Non-firm Energy Imports over Interties with Neighboring Regions (Scenario B2)



The role of transmission in resource adequacy

Transmission plays a major role in supporting resource adequacy:

- Allows generation to reach load
- Allows taking advantage of regional/interregional diversity to reduce the total amount of generation needed



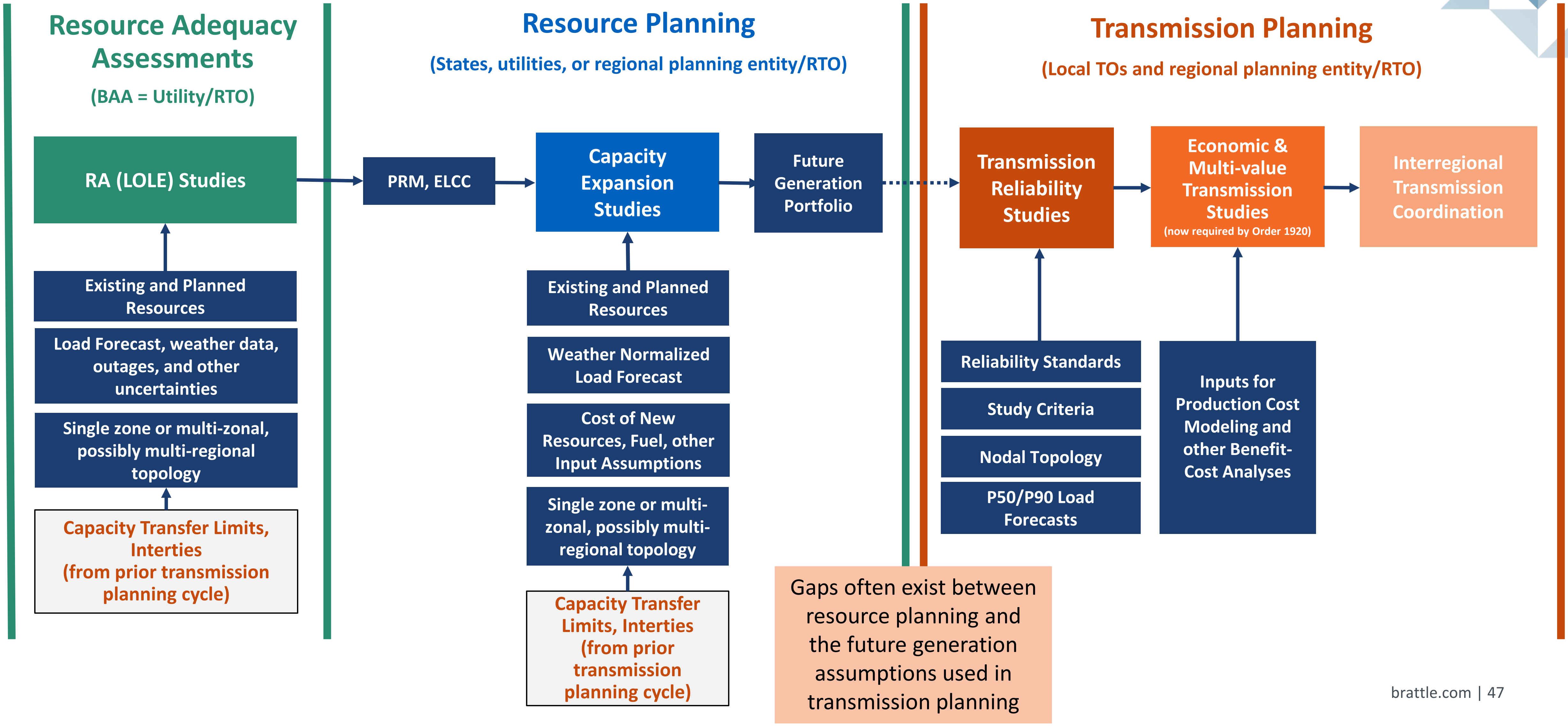
	Type of transmission	Resource Adequacy Value of this Type of Transmission
Local & Regional	T_{Load}	Connects loads that create RA requirements
Local & Regional	T_{Gen}	Connects new generation needed **to meet zonal/regional RA requirements**
Local & Regional	$T_{CapTrans}$	Enables cross-zonal capacity transfers within region, **reducing RA requirement and costs**
Local & Regional	T_{Other}	Other transmission needed to reliably (and efficiently) deliver generation to serve load
Interregional	T_{CapImp}	Enables resource-specific **capacity imports** from neighboring regions to meet RA requirements
Interregional	T_{Uncom}	Non-firm imports over uncommitted capacity **reduce regional RA requirements** due to interregional load and resource diversity

Siloed transmission planning processes do not fully value RA

	Considered in → / Type of transmission ↓	Local Reliability Planning	Generator Interconnection Queue	Transmission Service Requests	Regional Reliability Planning	Regional Economic & Public Policy Planning	Interregional Coordination
Local & Regional	T_{Load}	Explicitly Considered / Commonly Used			Explicitly Considered / Commonly Used		
Local & Regional	T_{Gen}	May Be Considered / Sometimes Used	Explicitly Considered / Commonly Used		May Be Considered / Sometimes Used		Explicitly Considered / Commonly Used
Local & Regional	$T_{CapTrans}$		May Be Considered / Sometimes Used			May Be Considered / Sometimes Used	
Local & Regional	T_{Other}	Explicitly Considered / Commonly Used		Explicitly Considered / Sometimes Used	Explicitly Considered / Commonly Used	Explicitly Considered / Sometimes Used	May Be Considered / Sometimes Used
Interregional	T_{CapImp}			Explicitly Considered / Sometimes Used	May Be Considered / Sometimes Used		Explicitly Considered / Sometimes Used
Interregional	T_{Uncom}						May Be Considered / Rarely Used
	Effectiveness of planning processes for addressing resource adequacy needs	Not focused on RA (RA benefits incidental)	**Effective but slow**; causes significant delays in achieving RA requirements	**Effective but often slow**; only for unit-specific capacity imports	Not focused on RA (RA benefits incidental)	**Potentially effective but often slow** (if transmission is focused on RA)	**Ineffective**; diversity value often not fully considered in planning

Is Transmission Type Considered in Process?	Explicitly Considered	May Be Considered
How often is the Process used for Transmission Approvals?	Commonly Used	Sometimes Used	Rarely Used

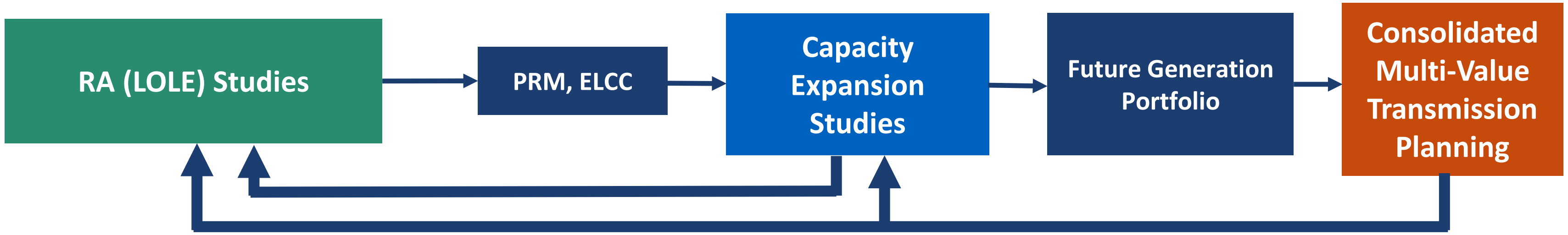
A gap in planning models contributes to seams inefficiencies



Solution: Better integration of RA, generation, and transmission planning

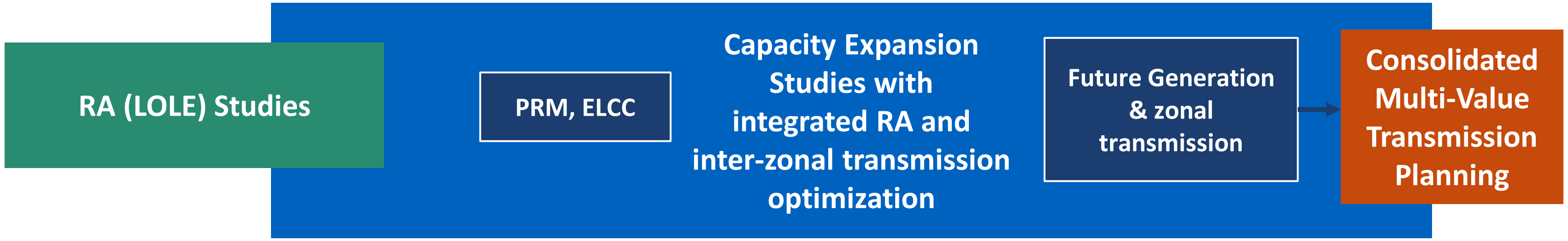
Option 1: Iterative RA, capacity expansion, and multi-value transmission planning

- RA value of transmission explicitly quantified in multi-value transmission planning (e.g., MISO LRTP)
- Iterative either within same planning cycle or (at least) across subsequent planning cycles
- Example: CPUC-CEC-CAISO coordinated (and iterative) planning process



Option 2: Capacity expansion modeling co-optimized with RA and zonal transmission

- Capacity expansion models with integrated RA and zonal transmission co-optimization
- Offers more optimal starting point for detailed transmission planning, endogenously capturing RA value
- Requires expansion model with calibrated/verified RA and transmission expansion representation
- Example: SPP Future Energy and Resource Needs Study (FERNS)



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Conclusions

Overall Conclusions on Market Seams

The efficiency of regional markets has highlighted significant inefficiencies related to the intertwined seams between regions. These inefficiencies can and should be addressed:

1. Ineffective interregional planning requires new approaches and federal/state involvement
2. Coordinated inter-regional generator interconnection processes can reduce costs and interconnection delays
3. Neighboring regions need to continue to improve managing the operational, congestion management, and market impacts of the loop flows they impose on each other
4. Interregional trading inefficiencies can be addressed through "intertie optimization"
5. The resource-adequacy and resilience benefit of (even uncommitted, non-firm) interregional transmission needs to be recognized in resource adequacy requirements and transmission planning

Recommendations from Barriers and Opportunities to Realize the System Value of Interregional Transmission (June 2024)

NREL

The National Laboratory of the Rockies recommends similar reforms to "significantly enhance the value of interregional transmission and deliver additional within-region benefits":

Common Actions

- Develop a framework for resource adequacy sharing among regions
- Support joint studies to identify transfer needs during extreme events and develop operational procedures to mitigate issues
- Evaluate internal transmission system ability to accommodate large power transfers as the underlying generation mix changes

Nonmarket and Hybrid Actions

- Implement coordinated scheduling and operations platforms or consolidation
- Pursue joint congestion management programs and reevaluate qualified paths for congestion management
- Develop consistent methods to calculate available transfer capacity
- Update processes to prioritize system reliability in scheduling market and wheeling transactions

Market Actions

- Eliminate fees and improve price forecasting for coordinated transaction scheduling or move toward intertie optimization
- Update corridor flow limits, automate procedures, and align assumptions for congestion management programs
- Revise interface pricing methods and validate interregional transactions
- Integrate operational control of merchant HVDC lines with regional market operations

Transformative Actions

- Conduct long-range, nationwide interregional transmission planning
- Implement interconnection-wide intertie optimization
- Establish a national system operator and planner to coordinate national network planning, scheduling, and resource adequacy functions

- **Recognize resource-adequacy and resilience value of interregional transmission**
- **Improved coordination and joint congestion management**
- **Depancaking**
- **Improved intertie pricing**
- **Move toward intertie optimization**
- **Interregional planning**
- **Interconnection-wide optimization**

Thank You!

Comments and Questions?

About the Speaker

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(webbio and publications)

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 former 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.

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