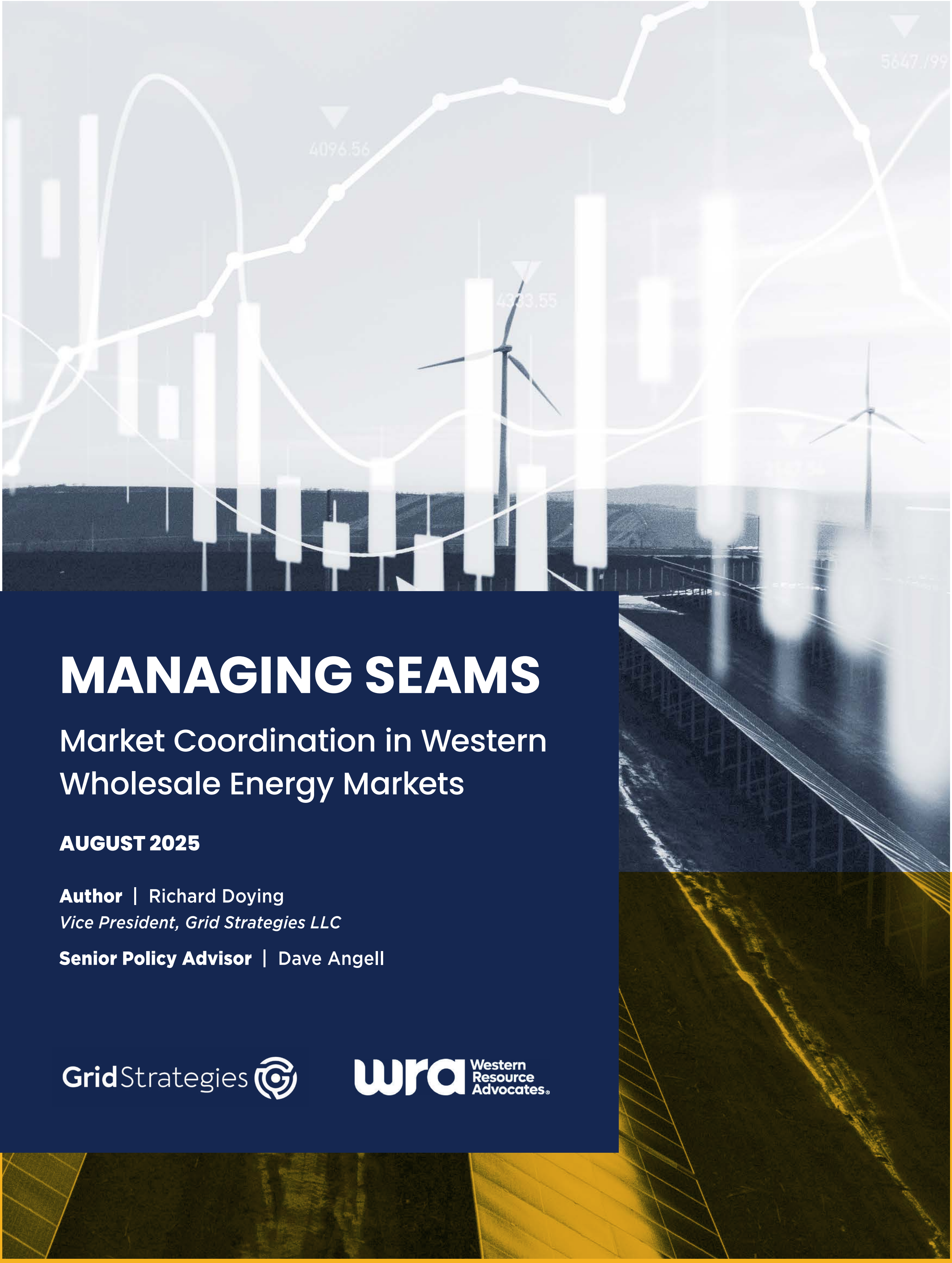


# MANAGING SEAMS

## Market Coordination in Western Wholesale Energy Markets

**AUGUST 2025**


**Author** | Richard Doying
*Vice President, Grid Strategies LLC*

**Senior Policy Advisor** | Dave Angell


GridStrategies

wra Western Resource Advocates

# CONTENTS



**Report prepared for Western Resource Advocates. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of Grid Strategies LLC's clients or other consultants. Grid Strategies would like to thank David Angell, who served as a technical consultant, and the other industry participants who provided essential background information, personal insights and feedback on the issues addressed in this report.**

# SUMMARY

Organized wholesale energy markets in the West have delivered substantial benefits to consumers. Real-time energy imbalance markets have produced $7.5 billion in savings since 2014[1] and enhanced the ability of the region to respond to reliability challenges during extreme weather events. The addition of day-ahead markets will further enhance reliability and increase economic gains by bringing the efficiencies achieved through real-time resource optimization to the day-ahead scheduling process. Offsetting these benefits, the expected fragmentation of current real-time markets in the West into multiple subregional markets will introduce barriers to regional energy transfers by increasing the costs and risk of scheduling energy between markets. The consequences extend beyond less efficient dispatch and higher consumer prices. Energy market seams will result in a less reliable system and adversely impact bilateral energy and capacity trading, reserve sharing arrangements, resource adequacy programs, resource and transmission expansion, and the cost of meeting public policy goals, such as reducing greenhouse gas emissions.

Market seams are not unique to the Western Interconnection; they are a common element of wholesale power markets in the United States and elsewhere. The operational and economic impacts of market seams have been studied extensively and described in several prior reports evaluating energy market developments in the West. Efforts to mitigate the negative impact of market seams in Eastern RTO markets have been pursued since markets were first introduced in the late 1990s. Experience in those markets can provide insights into potential seams mitigation measures that can be adopted in the West. However, the Western Interconnection is unique in many respects, and it will not be possible to simply transfer mitigation measures implemented in other markets.

1 California ISO estimates WEIM savings of $7.4 billion, *Western Energy Imbalance Market Benefits Report*, Second Quarter 2025, July 31, 2025. SPP estimated WEIS savings of $61 million, Benefits of the Market: Western Energy Imbalances Services, March 27, 2023.

Moreover, as described in an earlier report by Grid Strategies, solutions adopted in other RTOs have had their own challenges and while they may provide a framework, there may also be modifications or enhancements available to make them more effective in the West.[2]

The introduction of market seams will disrupt existing trading patterns and significantly reduce wholesale energy trading. Markets facilitate trade by reducing barriers to trade through greater transparency, reduced transaction costs and lower administrative barriers, such as the need to procure or preschedule transmission within the market. Market seams create barriers by decreasing transparency, increasing costs and adding administrative burdens. Barriers reduce trade between markets resulting in less efficient resource utilization and higher costs for consumers. In addition, although transactional barriers limit scheduled flow between markets, energy transfers within each market impose unscheduled flows ("loop flow") between markets, which can cause transmission congestion, reliability challenges, and cost shifts between transmission system users.

This report evaluates the direct impact of market seams and actions that must be taken by those who facilitate the market and are responsible for grid operation, including market operators, balancing authorities, reliability coordinators, and transmission operators, to protect reliability and mitigate the negative commercial impact of seams. The report also highlights indirect impacts, such as downstream financial impacts to operating reserve sharing and resource adequacy programs or impacts to resource or transmission planning processes. In these cases, action must be taken by others to ensure market seams impacts are evaluated, understood and mitigated to the extent possible. This will require action by nearly every segment of the industry including transmission system users, market participants, transmission planners, the Western Power Pool, and regulators responsible for managing consumer impacts.

For market participants, particularly suppliers and load-serving entities, it will be critical to understand and prepare for what will become a more complex trading environment. Wholesale energy markets are trading platforms connecting willing buyers and sellers. Market membership decisions are about choosing your trading partners. Trading between participants within a single market is largely frictionless, with real-time bid-based dispatch ensuring all potentially profitable transactions are scheduled and flow. Trading with entities external to the market is more costly, less flexible, entail higher delivery and price risk, and for some products, such as generation capacity, will be largely unavailable. As discussed throughout this report, this dynamic has significant implications for existing energy and capacity supply arrangements, and for future Integrated Resource Planning (IRP) efforts.

Many entities will have a role in identifying and managing the adverse impacts of seams. The recommendations below are divided into categories by the entities most impacted and responsible for addressing the issue. In many cases, other entities will also be directly involved in the process of developing solutions. The order of recommendation is not intended to reflect priority or imply a relative timeline. When establishing priorities and a timeline, it will be important to consider the launch timelines of EDAM and Markets+ and how membership in each market will change over time.

---

2 Grid Strategies LLC, *Market Configuration Matters: Effects of Market Choices on Consumers in the Northwest US*, June 2024.

# RECOMMENDATIONS

| Responsible Entity | ID | Requirement Description |
|---|---|---|
| Balancing Authorities (BA) | BA 1 | Evaluate, revise, or negotiate new BA-BA, BA-Market Operator coordination agreements to ensure compatibility with new markets and address new seams. |
| | BA 2 | Evaluate performance and financial implications of market seams for reserve sharing arrangements. |
| Market Operators (MO) | MO 1 | Establish interface prices. |
| | MO 2 | Develop rules and procedures for interchange source/sink monitoring and validation. |
| | MO 3 | Develop congestion management protocols and incorporate them into day-ahead and real-time markets. Pending completion of Enhanced Curtailment Calculator (ECC) effort, simplified methods should be considered leveraging existing congestion management mechanisms:<br>a. Market-to-non-market to limit flows on external non-market systems.<br>b. Market-to-market for market-based congestion management with external markets. |
| | MO 4 | Evaluate and consider implementing:<br>a. Intertie bidding in day-ahead to enable non-point-specific supply offers or demand bids.<br>b. Enhanced real-time dispatchable trading options, including Coordinated Transaction Scheduling and Real-Time Dispatchable Transactions as proposed for SPP RTO.<br>c. Interchange optimization. |
| North American Energy Standards Board (NAESB) | NAESB 1 | Promulgate comprehensive congestion management standard for the Western Interconnection (Western Interconnection Loading Relief Business Practice Standard). |
| Reliability Coordinators (RC) | RC 1 | Complete development and lead implementation of NAESB ECC standard for congestion management in the West. Ideally, this will be done prior to the need for market-to-market congestion management. |
| | RC 2 | Evaluate and revise RC-RC coordination agreements to ensure compatibility with new markets and address new seams. New agreements may be needed, for example, between BC Hydro and SPP RC or between the Alberta Electric System Operator RC and SPP RC. |
| | RC 3 | Coordinate with Balancing Authorities and Market Operators to evaluate and update emergency operating procedures. |
| Transmission Service Customers (TSC) | TSC 1 | Evaluate existing contractual arrangements to identify potential changes to comply with new market scheduling requirements or to address financial exposure if contract requires energy delivery across a market seam. |
| | TSC 2 | Update resource planning processes and tools to reflect realistic assumptions about availability and cost of imports. |
| | TSC 3 | Evaluate performance and financial implications of market seams for Western Resource Adequacy Program (WRAP) energy deployments. |

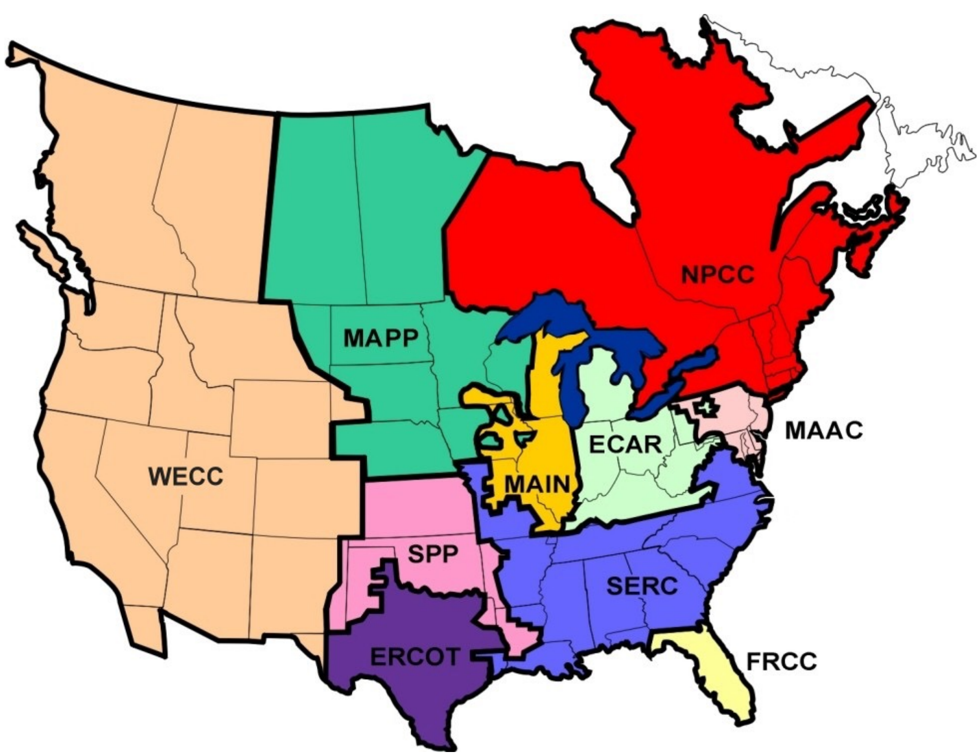
| Responsible Entity | ID | Requirement Description |
| --- | --- | --- |
| **Transmission Planners (TP)** | **TP 1** | Include accurate modeling of market configuration and economic hurdles to inter-market transfers. Ensure reduced economic flows due to market seams are reflected in benefits analysis. |
| **Transmission Owner/Service Providers (TSP)** | **TSP 1** | Convert from Rated System Path Methodology (NERC MOD 029) to Flowgate Methodology (NERC MOD 030) for determining available transmission and posting Available Flowgate Capabilities. |
| **Western Power Pool (WPP)** | **WPP 1** | Evaluate NWPP Reserve Sharing Program performance obligations and financial settlements in light of recently approved tariffs for EDAM and Markets+. |
| | **WPP 2** | Evaluate WRAP terms and performance obligations in light of EDAM and Markets+ tariffs. When developing operating protocols, consider the financial implications of scheduling resources across market seams. |

# WESTERN CONTEXT

There is a high degree of commonality in terms of transmission service and grid operations among the three electrical interconnections in the U.S., which is not unexpected given the influence of NERC, FERC and NAESB, in an industry with a rich history of sharing and adoption of industry best practices. There are also important differences between the Western and Eastern Interconnections that are relevant to the discussion of market seams. For instance, differences in operational practices in the West and East, and the tools that have been developed to manage transmission congestion caused by loop flow, have implications for options available to manage market seams impacts. It is important when evaluating market seams mitigation approaches in the West to consider that while experience in other RTO market contexts may be instructive, significant regional differences must be recognized and market seams mitigation measures in the West must be tailored to local conditions and needs.

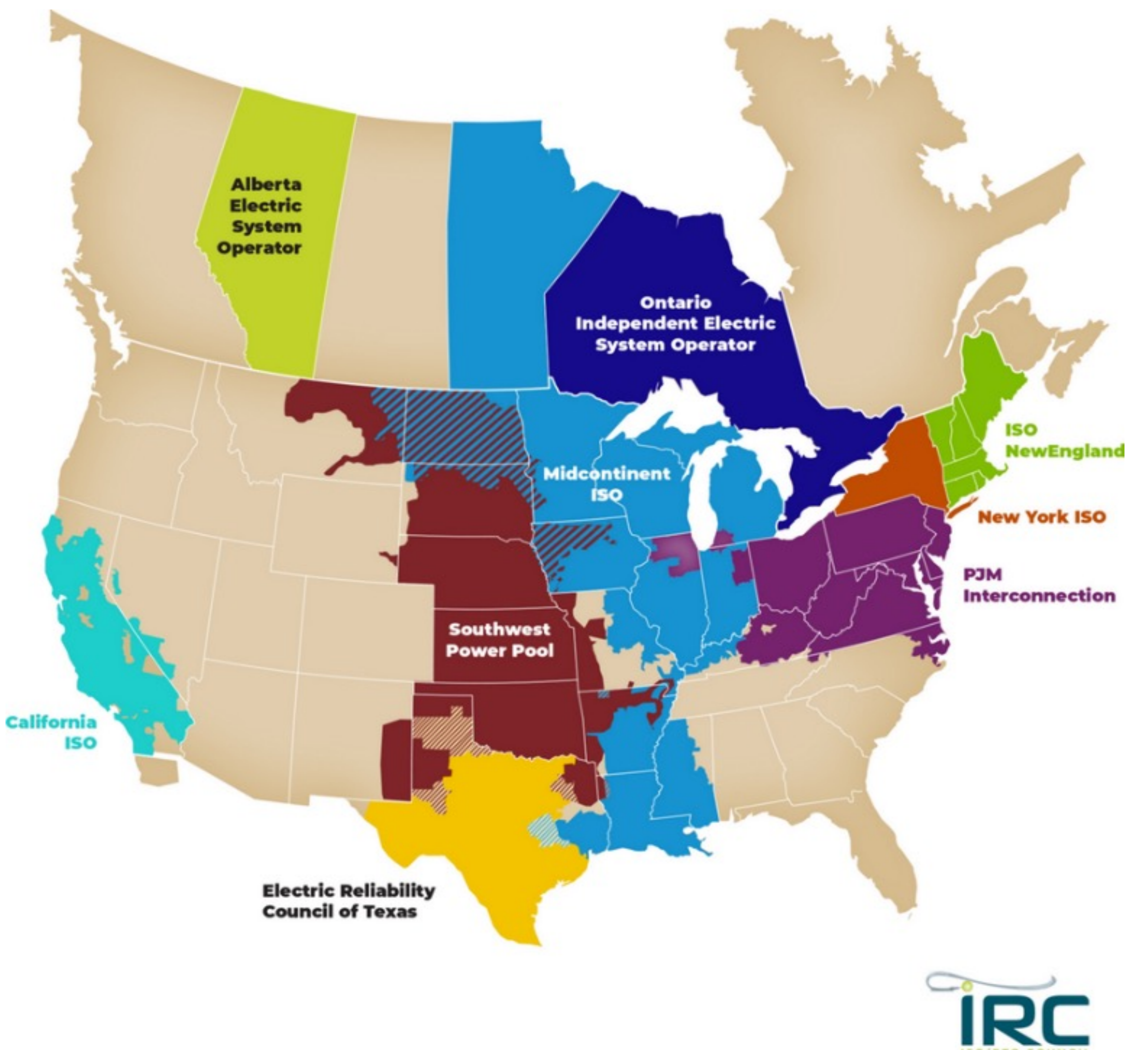
One important difference in the evolution of the Western and Eastern Interconnections relates to the nature of coordination between utilities in the region and the overlay of market footprints with other forms of coordination. Markets in the East tended to evolve from preexisting power pools, typically contiguous with NERC regions. Figure 1 shows NERC subregion boundaries in the late 1990s and early 2000s as wholesale electricity markets were initially developed. Coordination in many areas of the East included resource pooling arrangements such as centralized dispatch of member generation or sharing of operating reserves. These subregional collectives within the Eastern Interconnection tended to operate on a stand-alone basis with relatively little coordination between neighboring subregions.

**FIGURE 1** | **NERC Regions During Peiod of ISO/RTO Market Formation in early 2000s.**



Historical patterns of coordination in the East were solidified with the advent of ISO/RTOs and today Eastern RTOs operate largely as islands within which energy and capacity trading, resource adequacy planning, operating reserve sharing, and transmission planning occur. Figure 2 shows RTO market boundaries. Market activity at RTO seams, when it does occur, is primarily limited to opportunistic energy trading and analysis shows that barriers to trade result in suboptimal transfers between markets. Resource adequacy mechanisms operate at the RTO level and little generation capacity is traded between markets due to the higher transaction costs and financial risks of delivering across a market seam. Interregional transmission planning has been limited and despite more than a decade of prodding by FERC, joint planning between RTOs is in its infancy. Overall, the value of coordination is largely realized within RTOs, but the greater potential value of the broad interconnected system is largely untapped.

**FIGURE 2** | RTO market map. ***Source: https://isorto.org/***




The West has a similar but distinctive history of utility coordination. Whereas the Eastern Interconnection developed as an aggregation of multiple independent NERC regions and power pools, the Western Interconnection is consolidated within a single NERC region — the Western

Electric Coordinating Council (WECC).[3] The Western Power Pool (WPP) oversees other forms of coordination, including a regional reserve sharing program and the voluntary Western Resource Adequacy Program (WRAP). Recently, coordination efforts in the West have extended to include region-wide transmission planning with the launch of the Western Transmission Expansion Coalition (WestTEC) effort. WECC and WPP have enabled utilities in the West to capture the benefits of scale available through coordination at the broad interconnection level.

Market evolution in the West has followed a very different path than in the East. Markets in the West did not develop as extensions of regional power pools. Centralized wholesale energy markets in the West were launched through a state-led initiative in California in 1998, followed by the onset of nodal trading by CAISO in 2009 and subsequently extended throughout the West via the Western Energy Imbalance Market (WEIM) and Western Energy Imbalance Service market (WEIS). That history of increasing coordination has served utilities in the West well and provided a firm foundation for continued coordination to meet the challenges of a more variable regional resource portfolio, rapid load growth, and more frequent extreme weather events.

A significant difference between Western and Eastern wholesale energy markets is in the congruence between markets and other forms of coordination, such as operating reserve sharing pools, resource adequacy programs, or transmission planning processes. In Eastern RTO regions, multi-state market development accompanied increased levels of coordination across all areas of system operations and planning. In contrast, in the West, after more than a decade of increasing coordination of markets, operations, and planning, the region is heading into a phase of devolution, with the unwinding of existing markets and the introduction of market barriers that will create impediments to efficient market trading. Unlike in the East, where the advent of RTO markets solidified regional coordination, the fracturing of wholesale energy markets in the West will disrupt both current energy trading and other beneficial forms of coordination.

3 In the late 1990, as wholesale energy markets where being developed in the East, the Eastern Interconnection included eight separate NERC regions. Since that time, regional consolidation has reduced that number to four.

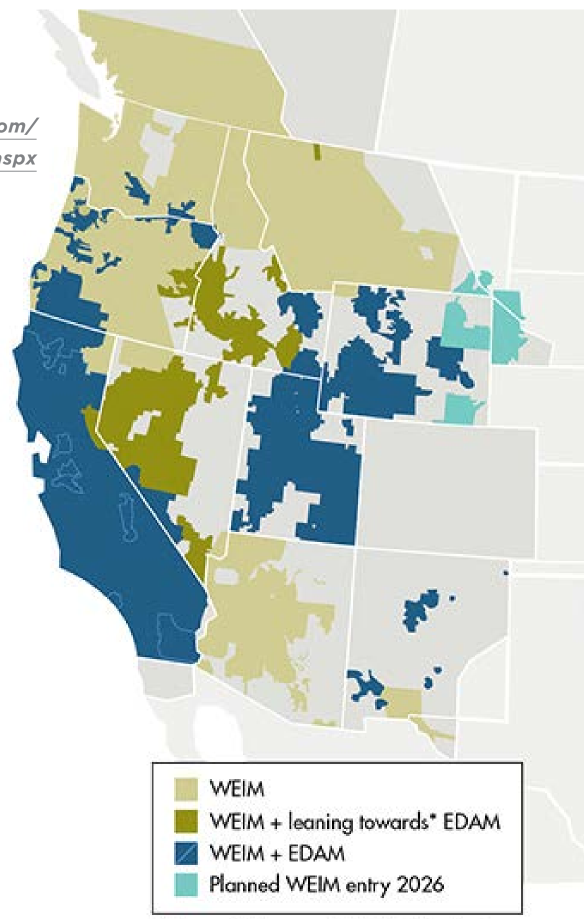
# WESTERN MARKETS CONFIGURATION

## General Issues

The reconfiguration of existing real-time markets into multiple smaller markets will significantly reduce the ability to transact across the West, decreasing the ability to realize the benefits of regional load and supply diversity, and limiting utility resource procurement options. The region is becoming more interdependent, relying on regional coordination to meet the challenges of growing load, a resource portfolio transitioning to wind, solar and storage, and an increase in the frequency of severe weather events. The fracturing of the market into multiple smaller markets imposes practical limits on future coordination and threatens the ability to meet the region's challenges. Figures 3 and 4 show EDAM, Markets+ and SPP RTO Expansion market boundaries.

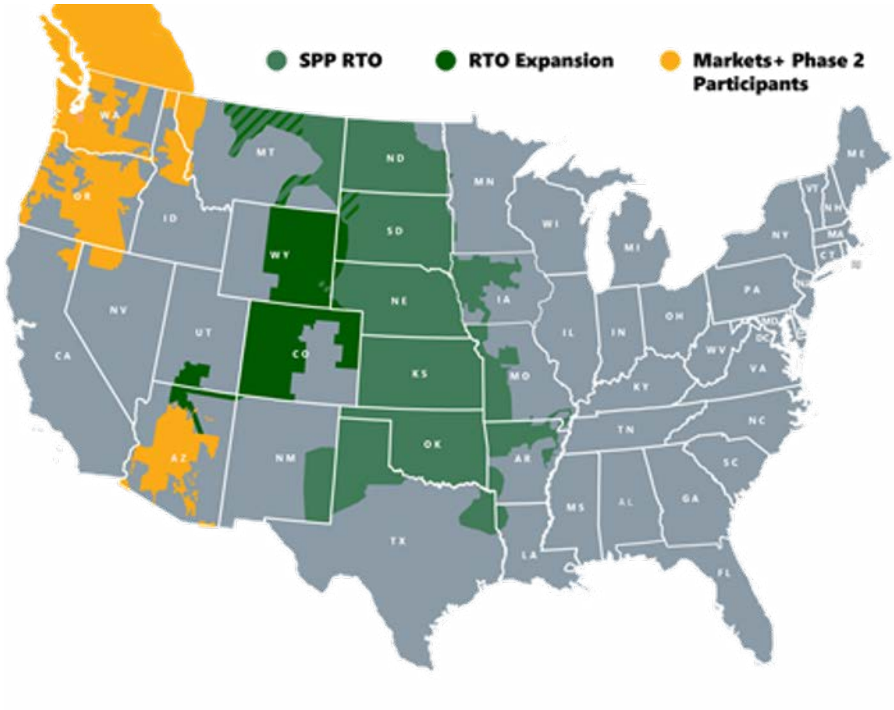
**FIGURE 3** | EDAM map.

*Source: [https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx](https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx)*




*These entities have publicly indicated a leaning towards EDAM as their preferred day-ahead market.

**FIGURE 4** | Markets+ and SPP RTO Expansion map. *Source: https://www.spp.org/marketsplus*




Day-ahead trading across markets seams will be available but as discussed more fully below, such trading will decrease dramatically due to increased transaction costs, the loss of price transparency and the introduction of scheduling hurdles. More importantly, current intra-hour dispatchable transactions will largely cease as neither EDAM nor Markets+ supports non-source-specific real-time dispatchable transfers. This will substantially diminish the value of regional load and resource diversity as resources are trapped within their native market region and are unable to export to meet needs in external systems.

The irregular configurations of EDAM and Markets+ will introduce additional challenges not experienced in other wholesale energy markets. As described earlier, most U.S. wholesale markets arose from groups of highly interconnected utilities with a history of mutually beneficial coordination. These markets largely reflected an evolution from preexisting coordinated operating and commercial arrangements to competitive wholesale energy markets. RTO markets in New England, New York, and PJM were developed as extensions of existing jointly operated tight power pools. The SPP region likewise developed based on power supply pooling arrangements started during World War II. The West is unique in that after more than a decade of increasing coordination, the advent of EDAM and Markets+ will reflect both a step forward as day-ahead market functionality is added to the current real-time markets, and a step backward as the existing real time market is broken into smaller submarkets introducing new barriers to trade, separating historical trading partners, and interrupting existing trading patterns and other forms of coordination.

This situation will be particularly acute within Markets+, which, due to a lack of physical transmission interconnection, will effectively be comprised of two distinct submarkets unable to interact other than by market participant-initiated transfers between the Markets+ Northwest and South subregions. Such transactions will require crossing two market seams. A transfer from Markets+ Northwest to Markets+ South, for example, will require an export from Markets+ Northwest, an import to EDAM, an export from EDAM, and an import to Markets+ South. Each import and export transaction will require procurement and payment for transmission, submission of schedules in both EDAM and Markets+, and payment of energy and associated congestion costs.

Prior market benefit studies did not evaluate outcomes for a non-contiguous market. The internal Markets+ seam and need to wheel through EDAM or CAISO to transact between Markets+ Northwest and Markets+ South introduces a significant hurdle to transactions between Markets+ participants. FERC has not previously accepted a market with a non-contiguous footprint and hence there are no insights to draw from other markets into the effectiveness of participant scheduled transactions as a means of optimizing internal market flows. Eastern RTO markets have demonstrated that a market seam significantly reduces trading volumes and efficiency between adjacent markets. Moreover, transfers across multiple market seams, for example, from PJM, through MISO, to SPP, are uncommon other than in emergency conditions. Hence the evidence available, suggests the internal Markets+ seam will be a significant barrier to trade and a source of inefficiency.

The prevalence of path-based transmission management will further impede transfers between markets in the West. Real-time market transfers within EDAM and Markets+, as in WEIM and WEIS, will be determined using a flow-based market clearing process, limited primarily by the physical capability of the underlying transmission system.[4] Transfers between markets require obtaining import/export transmission service, which is available on a more limited contract path basis. The use of path-based processes to evaluate and grant transmission service results in lower potential transfer capability than is available with flow-based internal market dispatch and hence will support lower levels of cross-seams trading.

## Northwest Issues

The introduction of market seams will create a challenging operating and commercial environment in the Northwest. The region is characterized by a highly fragmented but interwoven set of utility service territories and balancing areas, with a complex transmission and generation ownership overlay. The current imbalance market facilitates transactions across this complicated landscape and provides substantial reliability and economic benefits. In the near future, market participants will be separated by new market seams, introducing new costs and commercial risks. At the same time, the Northwest is facing unprecedented load growth and becoming increasingly reliant on the rest of the West to meet local energy supply needs. The market seam between EDAM, SPP RTO expansion and Markets+ South will decrease the availability of imports and limit future procurement opportunities for Northwest loads.

Given currently announced plans, the Pacific Northwest is anticipated to include multiple market seams, with utilities participating in or directly interconnected to WEIM, EDAM, and Markets+.

4 Of necessity, all markets incorporate operating limits in addition to individual transmission element line ratings. The complexity of the Western Interconnection and use of path-based processes for transmission service increases the prevalence of the use of non-flow-based limits on dispatch.

Transactions between markets will face complex scheduling requirements and high levels of price uncertainty. BPA, the largest Pacific Northwest transmission owner and operator, operates in six states, has interconnections with more than a dozen transmission service providers, will be located on the seam with EDAM, and will be isolated from peer utilities in Markets+ South. Utility configuration is complex in the Northwest; in several instances, utilities in the Northwest have loads and resources located on external systems, which in some cases will be in a different market.

Although the final market configuration is not yet known, based on current announcements, load-serving entities in the region will be required to schedule across the market seam on a routine basis to meet daily supply obligations. BPA, for example, serves load through the PacifiCorp transmission system and as such will become an EDAM participant to serve that load in 2026. Conversely, PacifiCorp serves load in areas that rely upon BPA transmission for energy delivery. The complexity of ownership and contractual arrangements and the resulting need to schedule across market seams make it essential to address loop flow issues and reduce barriers to trading between markets.

For the hydroelectric-rich Pacific Northwest, market barriers will be an important issue. The Northwest has long been a major exporter to California and the Southwest. Prior analysis has found that a market seam between EDAM and Markets+ will result in hydro curtailment with low-cost hydro trapped in the Northwest. Although the physical transmission capability will exist to facilitate the transfers, market barriers will make it uneconomic.[5] The situation is in fact worse than the study suggests as the study assumed Markets+ connectivity and the ability to seamlessly transact between the Markets+ Northwest and Markets+ South. The extent of stranded hydro will be greater given the inability of Northwest hydro, concentrated in Oregon and Washington, to participate in the sub-hourly real-time dispatch of resources to serve Markets+ South load in Colorado, Arizona and New Mexico. This will reduce the value of exports from the Pacific Northwest's very flexible hydro system, which would otherwise serve as a natural complement to the growing solar and wind resource portfolio in other parts of the West.

At the same time, imports are becoming increasingly important to the Northwest, which is experiencing rapid load growth. The 2025 PNUCC Northwest Regional Forecast shows winter peak load growth of over 10 GW, to a total of 51.5 GW by 2035.[6] Utility IRPs include 1.9 GW of committed resources, primarily solar and storage, and nearly 30 GW of needed, but not yet committed capacity. Nearly two-thirds of the uncommitted supply is identified as wind, solar, and hybrid renewable/storage. Many of the uncommitted resources have an unspecified source location, and some are noted as being located outside of the Northwest. The BPA 2025 White Book highlighted the ability of the Pacific Northwest to purchase or transmit from external markets as a key resource planning uncertainty for the region.[7] Market seams will introduce new financial and delivery risks that have all but eliminated capacity trading between markets in the East. It will be important for resource planners in the Northwest to reflect the impact of seams on capacity import availability.

5 Energy and Environmental Economics (E3), *Western Markets Exploratory Group Western Day Ahead Market Production Cost Impact Study*, p. 19, June 2023.

6 Pacific Northwest Utilities Conference Committee, *Northwest Regional Forecast of Power Loads and Resources: August 2025 through July 2035*, April 2025.

7 Bonneville Power Administration, *2025 Pacific Northwest Loads and Resources Study: The White Book*, p. 11, May 2025.

Resource expansion planning in the Northwest will also need to incorporate the impact of market seams on spot energy availability. BPA's most recent resource plan found that the most efficient supply portfolio to meet rising demand comprised energy efficiency, demand response, solar, and market purchases.[8] BPA's analysis did not model the expected market seam that will separate many Northwest utilities from the rest of the region and therefore likely overstated the availability of spot market energy. However, BPA's analysis did include sensitivity analysis that found that higher energy prices or lower market liquidity would increase the need for additional physical resources.[9] The commercial barriers brought about by the seam with EDAM and lack of connectivity to Markets+ South will increase spot market prices and decrease liquidity in the Northwest. It will be important for resource planning analyses to reflect the lower availability and higher cost of spot purchases due to the market seam separating the Northwest from potential suppliers elsewhere in the West.

## Southwest Issues

Separation of Southwest utilities into multiple markets and the lack of interconnection between Markets+ South and Markets+ Northwest will cut off parts of the Southwest from historical trading partners at a time when the Southwest is becoming more reliant on the rest of the

8 Bonneville Power Administration, *2024 Resource Program*, p. 52, February 21, 2025.
9 Ibid, pp. 57-58.

West to meet growing load and to balance an increasing supply of solar generation. Barriers to trading across market seams will reduce economic transfers between the Southwest, California and the Northwest, and increase the need to rely on emergency procedures to move energy during extreme weather events.

Given currently announced plans, the Southwest will include multiple market seams, with utilities participating in or directly interconnected to EIM, EDAM, Markets+ and SPP RTO expansion. Historically, the Southwest has been a net exporter to California driven by unit ownership or other contractual arrangements (e.g., Palo Verde and federal hydro power), or opportunistic trading. The Southwest also benefits from trade to and from the Pacific Northwest, benefiting from load and resource diversity. The growth of solar capacity in the Southwest will increase the value of such trade. Southwest imports and exports will face new barriers as transactions will require scheduling across the EDAM and Markets+ seams. As noted earlier, transfers within Markets+ between the South and Northwest will depend on market participant-initiated transactions and will be subject to energy, congestion and transmission delivery costs to transfer across EDAM. This will result in a dramatic decrease in trade volume for the Southwest, and real-time dynamic dispatch of the growing Southwest renewables portfolio for export to CAISO or the Northwest will be unavailable.

The Southwest is also experiencing load growth and an unprecedented transition from coal to wind and solar resources. The most recent regional resource adequacy assessment for the Desert Southwest forecasts annual load growth of 2.4% reaching approximately 33 GW by 2033. At the same time, baseload coal will decline to less than 1 GW and wind and solar will increase to 23.4 GW.[10] The substantial growth in variable generation increases the value of real-time trade with neighboring geographic regions, which would enable the Southwest to capture the regional supply and demand diversity benefits to address both excess and short supply situations. The numbers cited above reflect utility IRPs from 2021. Given the recent surge in demand in the West, the degree of resource portfolio change in the Southwest, and the relative value of geographic regional diversity are likely even greater.

Market seams will limit the ability of the Southwest to realize regional diversity benefits. Barriers to trade between the Southwest and the remainder of WECC will be detrimental from both economic and reliability perspectives. The E3 report notes that tightening reserves across the West have increased prices and decreased liquidity, raising resource adequacy risks and creating challenges in responding to extreme weather events.[11] While the need for flexibility and access to regional diversity is growing in the Southwest, market seams will further reduce liquidity by creating barriers to trade, reducing the ability of the Southwest to access that diversity.

10 Energy and Environmental Economics, *Resource Adequacy in the Desert Southwest*, April 2022.
11 Ibid, p. 18.

# SEAMS FOCUS AREAS

Market seams directly impact energy trading by imposing new administrative barriers, transaction costs, and price risks on energy transfers between markets. Market seams also have secondary, downstream impacts. In the West, several region-wide mechanisms span market boundaries and will be impacted by markets seams. Some, such as congestion management, reliability entity coordination (RC-to-RC, BA-BA), or reserve sharing, operate in the operating timeframe. Others, such as resource adequacy, or transmission planning operate over a longer timeframe. In all cases, market seams present new challenges that will need to be evaluated and understood. In some cases, mechanisms or processes may require modification to ensure they remain effective or to mitigate new financial risk.

## Congestion Management

**RECOMMENDATIONS** ▶ RC 1, TSP 1, NAESB 1

There is no West-wide process to manage congestion. The only structured process to manage congestion in the West is the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP). This process is utilized on a very limited basis, involving just six utilities and including only four "Qualified Paths" for which phase angle regulators can be used to manage flow. In some cases, the WIUFMP has been incorporated, with difficulty, into market dispatch processes.[12] Overall, the WIUFMP does not provide a suitable foundation for market operations.[13] On paths not included in the WIUFMP, individual balancing authorities manage congestion on their systems using proprietary procedures, relying on generation redispatch, point-to-point schedule curtailment, or system reconfiguration.

12 CAISO was prompted to develop a special operating procedure to implement WIUFMP congestion management on Path 66 (COI) to address imprecision in flow relief calculations. See *CAISO Operating Procedure 3510E, v. 2.2*, October 22, 2024.

13 An evaluation by the SPP ECC Task Force determined that "The WIUFMP is limited to only four paths, is outdated (created in 1996), and insufficient to address current congestion along BA seams, and is unprepared to address developing markets." *ECC Task Force Whitepaper: ECC Future State*, p. 3, April 30, 2024.

Congestion management is made more complex in the West due to the region's reliance on contract path-based processes. While effective from a reliability perspective, contract path-based processes do not accurately reflect physical flow on the transmission system and hence do not provide the level of granularity needed to accurately determine available transfer capability or manage real-time transmission overloads. The adverse consequences have been increasingly evident as markets have been implemented and expanded in the West. The transition to flow-based methods, undertaken by BPA, Arizona Public Service, and Salt River Project, offers significant benefits for both tariff administration and transmission system management.

Efforts are underway to move toward adoption of flow-based congestion management across the Western Interconnection. The North American Energy Standards Board (NAESB) has launched a working group, supported by RC West and SPP RC, to develop a new interconnection-wide congestion management standard for the West. This effort followed publication of a joint Reliability Coordinator Enhanced Curtailment Calculator (ECC) Task Force whitepaper that proposed a high-level design incorporating the flow-based constraint management process utilized throughout the Eastern Interconnection. The new standard will allow more accurate tracking of loop flow and the ability to implement a market-based approach to remediating congestion caused by loop flow between markets. Work on the new standard is expected to be completed in 2025.

## Reliability Entities and Operating Agreements

**RECOMMENDATIONS** ▶ RC 2, RC 3, BA 1

Addressing market seams in the Western region will be complex due to the overlapping requirements of multiple participating Transmission Service Providers' (TSP) Open Access Transmission Tariffs (OATTs). Procurement of transmission service will be governed primarily by participating member OATTs, with transmission flow subject to the combined requirements of both the market operator tariff and participating members' OATTs. This structure creates internal "seams" within both EDAM and Markets+ that require well-orchestrated coordination between the market operator and local TSPs. At the market seam, the level of coordination becomes much more complex and will require coordination between market operators and TSPs in both markets. This degree of coordination is far more extensive than in any of the Eastern RTOs, where the RTO serves as the single market operator and TSP for the region. The much greater division of responsibility and authority in the West will result in significant time being needed to negotiate and implement operating agreements and protocols for market seams coordination.

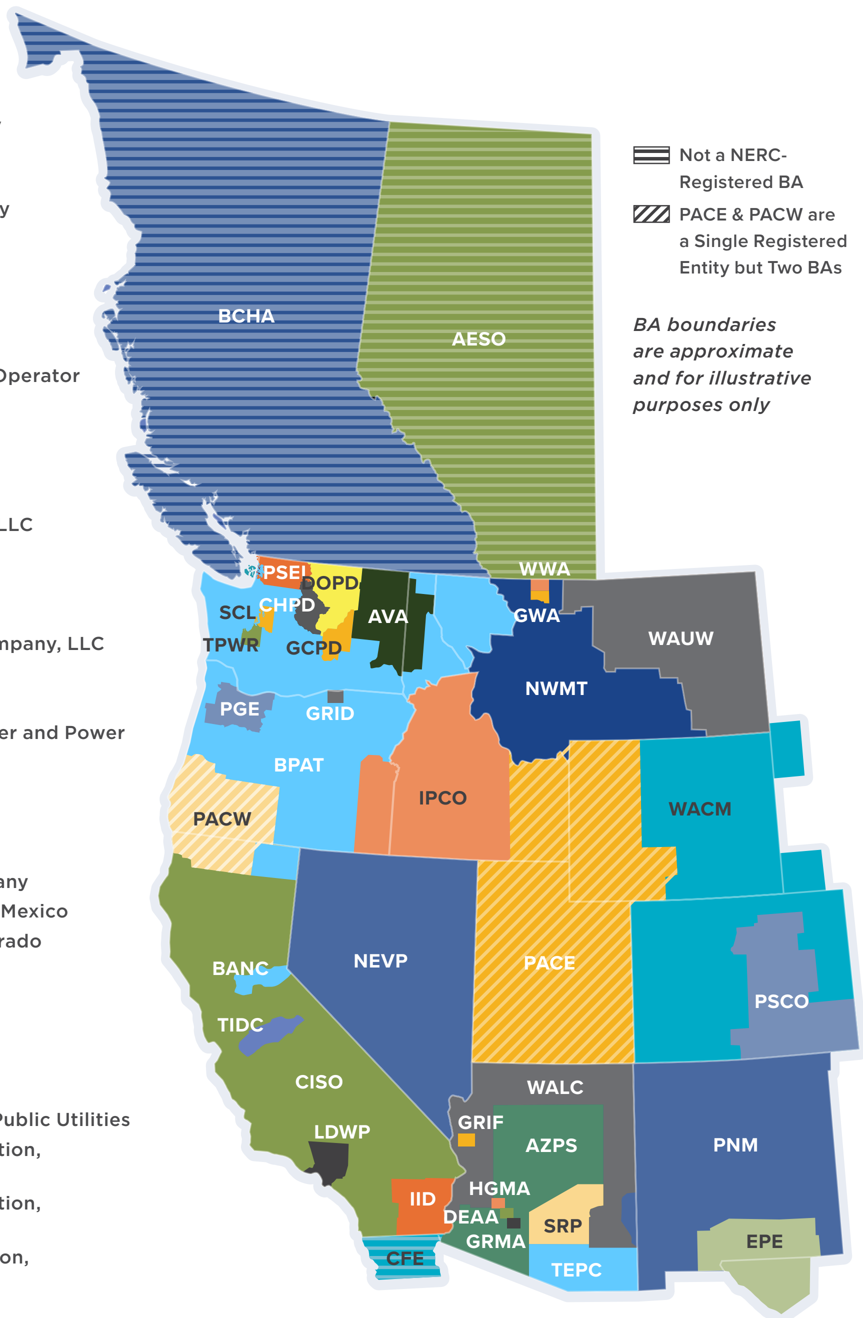
EDAM and Markets+ similarly include multiple Balancing Authorities (BAs). Figure 5 shows Western Interconnection Balancing Authorities. This has been the case for WEIM and WEIS since their inception. Current market operations are in some cases supported through BA-to-BA coordination agreements such as the CAISO and BPA Coordinated Transmission Agreement (CTA), developed to manage EIM flow over the BPA transmission system.[14] The continued

14 Bonneville Power Administration and CAISO, *Coordinated Transmission Agreement*, February 2017.

operation of multiple BAs within EDAM and Markets+ will complicate the seams coordination activities between EDAM and Markets+. For example, the CAISO and BPA agreement will need to be updated to reflect the implementation of EDAM and will need to be further modified or superseded by a new multi-lateral operating agreement for coordination with SPP upon the launch of Markets+.

**FIGURE 2** | Western Interconnection Balancing Authorities — January 5, 2017.

| | |
|---|---|
| **AESO** | Alberta Electric System Operator |
| **AVA** | Avista Corporation |
| **AZPS** | Arizona Public Service Company |
| **BANC** | Balancing Authority of Northern California |
| **BCHA** | British Columbia Hydro Authority |
| **BPAT** | Bonneville Power Administration \| Transmission |
| **CFE** | Comision Federal de Electricidad |
| **CHPD** | PUD No. 1 of Chelan County |
| **CISO** | California Independent System Operator |
| **DEAA** | Arlington Valley, LLC |
| **DOPD** | PUD No. 1 of Douglas County |
| **EPE** | El Paso Electric Company |
| **GCPD** | PUD No. 2 of Grant County |
| **GRID** | Gridforce Energy Management, LLC |
| **GRIF** | Griffith Energy, LLC |
| **GRMA** | Gila River Power, LP |
| **GWA** | NaturEner Power Watch, LLC |
| **HGMA** | New Harquahala Generating Company, LLC |
| **IID** | Imperial Irrigation District |
| **IPCO** | Idaho Power Company |
| **LDWP** | Los Angeles Department of Water and Power |
| **NEVP** | Nevada Power Company |
| **NWMT** | NorthWestern Energy |
| **PACE** | PacifiCorp East |
| **PACW** | PacifiCorp West |
| **PGE** | Portland General Electric Company |
| **PNM** | Public Service Company of New Mexico |
| **PSCO** | Public Service Company of Colorado |
| **PSEI** | Puget Sound Energy |
| **SCL** | Seattle City Light |
| **SRP** | Salt River Project |
| **TEPC** | Tucson Electric Power Company |
| **TIDC** | Turlock Irrigation District |
| **TPWR** | City of Tacoma, Department of Public Utilities |
| **WACM** | Western Area Power Administration, Colorado-Missouri Region |
| **WALC** | Western Area Power Administration, Lower Colorado-Region |
| **WAUW** | Wester Area Power Administration, Upper Great Plains West |
| **WWA** | NaturEner Wind Watch, LLC |




GridStrategies

Reliability Coordinator (RC) functions within the EDAM, Markets+ and SPP RTO expansion footprints are provided by CAISO and SPP through RC West and SPP West. Figure 6 shows North American Reliability Coordinator regions. CAISO and SPP coordinate RC functions in the West under a joint reliability coordination agreement.[15] The current agreement covers coordination of transmission and generation outages, emergency operations, and unscheduled flow management using WIUFMP. This agreement, and other similar coordination agreements, will need to be evaluated and updated to reflect the new markets and their changing membership. New Reliability Coordinator-to-Reliability Coordinator agreements may also be needed, for example between SPP RC and British Columbia Hydro, with the start of Markets+. This will be particularly critical to the extent that BAs transfer between RCs to align market, BA and RC footprints. During highly stressed conditions, the region cannot afford confusion as to who has authority to provide reliability directives on the highly interconnected, jointly owned and operated Western grid.

**FIGURE 6** | NERC Reliability Coordinators. *Sour: https://www.nerc.com/pa/rrm/bpsa/Pages/RCs.aspx*


15 California ISO and Southwest Power Pool, *Reliability Coordinator Coordination Agreement*, July 15, 2019.

Market seams also increase the need for well-coordinated emergency operating procedures. Experience during past extreme weather events in the West has shown the value provided by real-time markets and the ability to quickly move power long-distances to address local shortages. The creation of new market seams will all but eliminate dynamic real-time trading between markets and the region should expect more frequent use of emergency operating procedures during extreme weather events. In the West, this will require agreements and operating procedures between multiple entities, including market operators, transmission system operators, balancing authorities, and reliability coordinators.

Experience in other markets has shown the potential risk of confusion and miscommunication when an emergency response requires involvement of multiple parties at a market seam. In a January 2018 winter weather event, MISO South experienced record cold and emergency operating procedures were implemented. A post-event review by MISO, SPP, Tennessee Valley Authority, and Southeastern Reliability Coordinators revealed that "lack of common emergency procedures and a lack of understanding of each other's systems increased the challenges faced during that event."[16] MISO's experience during that event highlights the critical importance of reliability coordination at market seams.

## Reserves Sharing

**RECOMMENDATIONS ▶ WPP 1, BA 2**

Most potential EDAM and Markets+ participants are currently members of the Northwest Power Pool Reserve Sharing Program.[17] The EDAM and Markets+ seam raises concerns about the viability of this program as participants will be separated into different markets and in some cases non-contiguous subregions within a single market.[18] Sharing of reserves in real time will entail energy transfers between program members when reserves are deployed. The EDAM and Markets+ tariffs include provisions to enable such transfers. Under both tariffs, deployment of operating reserves will constitute a sale of energy between market participants and settle financially at market clearing prices.

In some circumstances, deployment of operating reserves will involve a sale and purchase of energy across a market seam and will be subject to market settlement as an import/export transaction. This has significant implications for reserve sharing program participants as settlement prices will be unknown at the time of deployment and will be determined after the fact based on prevailing market clearing prices. Prices on either side of the market seam move independently, reflecting the underlying dynamics of the two separately dispatched and cleared markets. Price volatility and congestion costs, particularly when deploying reserves in the absence of market dispatch, will be unpredictable.

Participants in the Northwest Power Pool Reserve Sharing Program must evaluate performance

---

16 Midcontinent ISO, *Reliability Technical Conference Prepared Remarks of Meliss Seymour, Docket No. AD19-13-000*, p. 9, June 27, 2019.

17 Ten new members, primarily from the Southwest, joined the Northwest Power Pool Sharing Program in May 2024. Those companies included: Arizona Public Service Company; Arlington Valley, LLC; El Paso Electric Company; Griffith Energy, LLC; Imperial Irrigation District; New Harquahala Generating Company, LLC; Public Service Company of New Mexico; Salt River Project; Tucson Electric Power; WAPA - Desert Southwest Region.

18 Based on current company announcements, Markets+ will be divided into two non-contiguous sub-markets: a Northwest sub-market encompassing Bonneville Power Administration, Chelan County PUD, Grant County PUD, Puget Sound Energy, Tacoma Power, and a South sub-market encompassing Arizona Public Service, Salt River Project, Tucson Electric, El Paso Electric, Public Service Company of Colorado.

obligations and new financial risks arising from operation of the program across multiple markets.[19] As with power supply contracts or other bilateral agreements, participants may find opportunities to restructure the program to address new risks associated with market seams.

## Resource Adequacy

**RECOMMENDATIONS ▶ WPP 2, TSC 3**

Market seams will have similar implications for the Western Resource Adequacy Program (WRAP). WRAP is independent of either EDAM or Markets+, although participation in WRAP is mandatory for Markets+ members. WRAP operating protocols require transfer of energy between members under specified conditions. As with operating reserves, both EDAM and Markets+ include the ability to schedule WRAP resources to facilitate such transactions. Scheduled WRAP transfers will constitute energy transactions and, in some cases, transfers between markets, exposing WRAP members to unpredictable costs.

WRAP participants will include both EDAM and Markets+ members, so it is important to evaluate the potentially conflicting obligations for WRAP resources cleared or scheduled in the day-ahead markets. CAISO explained in its tariff filings that EDAM sought to ensure interoperability with WRAP but that actual experience with EDAM and WRAP will be needed to assess interoperability and address issues that may arise.[20] WPP has proactively formed a task force to evaluate interoperability issues, including energy deployment and delivery, holdbacks, and financial settlement. The task force is anticipated to complete its evaluation by the end of 2025, leaving sufficient time to modify the agreement or business practices to address identified issues.

One potential solution to address interoperability and financial exposure issues would be to restructure WRAP to align reserve calculations, sharing obligations, and energy transfers with market boundaries. This could entail, for example, a program with a common West-wide planning framework for determining reserve margin requirements and resource accreditation, with subregional pooling and sharing. This would preserve the benefits of the program although at a reduced scale, particularly for small market subregions with relatively low peak load and load diversity.

## Transmission Planning

**RECOMMENDATION ▶ TP 1**

Market seams will impact transmission planning and require modification of the economic analysis performed to evaluate transmission investment benefits. Potential new transmission investments are identified and assessed based on the extent to which they produce reliability or economic benefits, measured by reductions in production costs within the planning region. To provide realistic results, production cost models must accurately reflect energy market

---

19 In similar circumstances, utilities have elected to exit reserve sharing pools. Virgina Power determined it would not participate simultaneously in the PJM market and the neighboring VACAR regional reserve sharing pool and withdrew from the pool after joining PJM.

20 California Independent System Operator Corporation, *FERC Docket No. ER23-2686-000*, p. 143, August 22, 2023.

dynamics, including the non-physical, economic barriers to energy flows created by market seams. Analysis of trading across RTO market seams has shown that actual trade is far below efficient levels.[21] Market benefit studies conducted for the West have shown the same outcome. Transmission planning models must reflect the reduction of trade due to market seams. Failure to do will result in overestimating economic flows between markets and overstating production costs benefits of potential future transmission expansion.

In other situations, the opposite may occur, with failure to reflect market seams in planning studies understating the value of new transmission. New transmission that establishes or increases connectivity between subzones within a market may enable energy transfers that were not previously physically constrained but were uneconomic due to the additional cost of transacting across a market seam. In this situation, commercial barriers rather than physical constraints inhibit otherwise economic flows, justifying new transmission. [22] It is necessary that transmission planning processes reflect both commercial and physical limits to accurately identify and value potential transmission upgrades.

21 Brattle Group and Willkie Farr & Gallagher LLP, *The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission*, p. 3, October 2023.

22 Public Service of Colorado (PSCo) anticipates this will be the case in Markets+, explaining to the Colorado Public Utilities Commission that the key to realizing the benefits of Market+ participation is "concurrently executing on construction of a transmission plan connecting to Markets+ members, which will increase economic exchange of energy between members and lead to an overall reduction in the amount of accredited resource capacity that needs to be built market wide." *Public Service Company of Colorado, Direct Testimony and Attachments of Joseph C. Taylor, Proceeding No. 25A-0075E*, p. 56, Feb. 14, 2025.

# MARKET SEAMS MITIGATION

Market seams mitigation measures fall into three broad categories: protecting reliability, maximizing transmission utilization, and reducing transactional barriers. Seams mitigation practices in Eastern RTOs offer potential approaches in each of these areas. When considering options for the West, it is essential to evaluate the operational experience and effectiveness of seams mitigation practices utilized in other markets. In some cases, approaches have not delivered the hoped-for benefits or had unintended consequences. It is also important to consider the unique Western context and how that may influence the feasibility or effectiveness of different approaches, and to identify changes to adapt market design elements used elsewhere to fit the unique characteristics of the West.

## Managing Congestion

**RECOMMENDATION** ▶ MO 3a

Market-based unit commitment and dispatch by multiple market operators will result in substantial loop flow between markets in the West. At the same time, visibility into the source of loop flow will decline as resource scheduling transitions from point-to-point transactions to market-based dispatch. In the current market, day-ahead scheduling of Network Resources and import/export transactions are performed at the utility level. The extent of loop flow is limited by the amount of transmission service that has been allocated to facilitate delivery from designated network resources or sold for point-to-point transfers. With the implementation of day-ahead markets, unit commitment and dispatch decisions will be made on a market-wide rather than individual utility level. Regional power flows will change, in some cases significantly, as the day-ahead solution finds the lowest cost mix of resources to meet market-wide demand.

The use of security-constrained unit commitment and dispatch in the market clearing process ensures transmission flows remain within prescribed operating limits on the internal market transmission system, but flow impacts on external systems are not monitored and external transmission system constraints are not enforced in the market clearing process. Transmission flow resulting from least cost dispatch ("market flow"), like current Network Integrated Transmission Service (NITS) flow, is not tagged, masking the flow origins from external system operators. The phenomenon is not new but has traditionally occurred at a smaller level, for example, due to utility mergers and centralization of operations. With the start of the day-ahead markets, that centralization of dispatch and conversion from point-to-point to network flow will occur at a regional level. The degree of change to regional power flows and the difficulty of managing market loop flows on external systems will be significant and grow as new systems are added to each market.

Congestion management is the responsibility of the system operator where the constraint is located, regardless of the origin of flows contributing to the constraint. A system experiencing congestion due to loop flows from a neighboring market incurs a financial cost in the form of generation redispatch or curtailment of point-to-point schedules. To the extent that congestion is caused by loop flow that exceeds historical or agreed upon levels, redispatch results in a cost shift from the market to the external system and its users. For a non-market system, these costs may be reflected in increased fuel costs or lower transmission revenue. Within a market, such costs may be reflected in higher energy prices, uplift, or reduced funding of congestion revenue rights. In a worst-case scenario, market flows on an external system can exceed the congestion management capabilities of the external system, resulting in reliability events and the need to take emergency actions to mitigate congestion.

A primary objective of market seams management is protecting reliability through effective mitigation of loop flow and associated transmission congestion. In light of the importance of the issue, FERC required market seams congestion management processes to be implemented as a precondition for wholesale markets to launch in the East. To satisfy the requirement, Eastern markets developed processes, including joint-operating agreements between market operators, to manage loop flow on external non-market and market systems.[23] These procedures are generally designed to limit market flows on external non-market systems, thereby maintaining reliability and preserving equity between transmission users. The base process can be enhanced through market-to-market redispatch, to increase congestion management efficiency across two markets.

For market-to-non-market seams, these procedures are used to define a set of mutually agreed upon external transmission flow limits that market operators use to constrain market flows on external systems. This procedure could also be used at market-to-market seams but would restrict flows within each market below efficient levels. In addition, the process generates market flow data that is shared with external systems, enabling the identification of loop flow sources and assignment of congestion relief obligations. Thus, market-to-non-market congestion management provides a framework by which market processes (centralized clearing and economic redispatch) and traditional congestion management processes work in tandem to maintain reliability and provide equitable grid access for transmission customers within and external to the market.

The basic congestion management protocol underlying this process is the Eastern Interconnection Transmission Loading Relief (TLR) procedure. The TLR procedure is a flow-based process that has been adopted on an interconnection-wide basis. The use of an interconnection-wide procedure ensures it can provide comparable treatment for all transmission users, whether in a market or an external non-market system. The flow-based approach also allows greater utilization of the transmission system, avoiding the conservatism inherent in path-based approaches. Finally, the process is compatible with flow-based market dispatch utilized in all RTO markets and planned for EDAM and Markets+.

The lack of a common congestion management protocol, and the reliance on a path-based approach to calculate available transmission and curtail schedules in most of the West, makes

23 Congestion management protocols are a primary element of the Joint Operating Agreements (JOAs) between MISO and PJM (April 2005), MISO and SPP (March 2015), and NYISO and PJM (January 2013).

it impractical for EDAM and Markets+ to adopt the existing market-to-market coordination mechanism used in Eastern RTO markets. A uniform regional congestion management protocol is expected for the West in the future when the Enhanced Curtailment Calculator effort at NAESB is complete. The proposed NAESB standard largely mirrors the Eastern TLR standard and will provide the tools needed to implement a flow-based congestion management process for market coordination in the West.

Prior to the adoption of a West-wide congestion management process, market coordination could be pursued using the tools currently available. For example, flow restriction processes already in place in the West may be leveraged more widely. The CAISO and BPA Coordinated Transmission Agreement, for example, includes the calculation and exchange of market flow data and use of flow limits in WEIM dispatch to constrain flows on the BPA transmission system.[24] This process would not be suitable for market-to-market congestion management redispatch, and it would be burdensome to develop one-off agreements with all BAs located at market seams, but it nonetheless provides a conceptual framework that could be leveraged as an interim step toward a more robust market seams congestion management process.

Negotiation and implementation of a market seams congestion management process in the West will be much more complicated due to the number of parties involved in the process of providing access to and managing flows on the transmission grid. In the East, each RTO serves the combined role of market operator, transmission service provider, transmission system operator, and balancing authority. Therefore, only two primary parties engage in the negotiation and the result is a single Joint Operating Agreement that covers all aspects of seams coordination. In the West, these various functions are divided among multiple entities. Negotiation and implementation will include multiple counterparties and given the complexity of the seam will likely require multiple operating agreements.

## Protecting Existing Usage Rights

An important element of market seams congestion management coordination is protection of existing firm transmission system rights. Historically, utility transmission systems were designed and built to handle flows from multiple sources, including delivery of Designated Network Resources to network load, delivery of firm point-to-point transfers, and of necessity in an interconnected system, a reasonable level of loop flows from external systems. To deliver both reliable and equitable outcomes, a seams coordination process must include a mechanism to protect all three uses (network, point-to-point, loop flow). Financial congestion cost hedging mechanisms provide such financial protection against increased cost associated with changing flow patterns within a given market. A market-to-market or market-to-non-market congestion management coordination process must similarly protect holders of transmission rights against either cost shifts or loss of usage.

In Eastern markets, protection of existing rights was accomplished by determining a fixed set of “firm flow entitlements” reflecting historical system usage. Establishing fixed entitlements ensures continued availability of existing rights and fair allocation of congestion management

24 Bonneville Power Administration and CAISO, *Coordinated Transmission Agreement*, February 2017.

costs. However, locking in a set of entitlements is not without challenges. In Eastern RTOs, firm flow entitlements were established based on 2004 "premarket" transmission usage. Topology changes, generation additions and retirements, and load growth have changed flows substantially since 2004 and not all transmission customers view the set of historical entitlements established as fair. SPP, MISO and PJM have worked since 2004 without success to develop an agreed upon methodology to update the flow entitlements. Everyone can agree that conditions have changed and that a new baseline is necessary. No one can agree on a process to calculate a new baseline that will ensure equitable results.

Any process to develop flow entitlements in the West will need to incorporate the unique elements of the Western system and markets. Elements that may require special consideration in the West include joint ownership of transmission or unique contract provisions for scheduling and usage such as may be associated with jointly owned generation. The AC Pacific Intertie is one of several examples where jointly owned transmission may grant rights to users participating in different markets. Rights to delivery of output from Palo Verde represent another example, as delivery will require a transfer from Markets+ to EDAM. In some cases, such agreements may need to be modified or supplemented but in all cases, they represent non-standard transmission usage rights that must be considered as firm-flow entitlements are developed.

Once flow entitlements are determined, they must be incorporated into markets, and into transmission tariff administration and planning processes. Within markets, entitlements must be included as binding limits in each market operator's clearing process. While notionally straightforward, this requires extensive exchange of planning and operational data between market and system operators, consisting of, for example, real-time transmission flows, EMS models, generation status, transmission line status, real-time loads, and scheduled use of reservations. Calculated market flow data must be made available in real time to transmission service providers, reliability coordinators and balancing authorities in other areas (market and non-market) for use in congestion management processes.

The adoption of flow entitlements for market administration has downstream implications. To the extent they are used to limit flow in the operating horizon, flow entitlements represent a form of transmission constraint that must be reflected in congestion revenue rights markets and in resource planning and transmission planning processes to ensure planning models accurately reflect expected system operations. Importantly in the West, where transmission service will continue to be granted under participating member OATTs, transmission service providers must also reflect flow entitlement limits on external systems when evaluating and granting requests for new transmission service.

## Maximizing Transmission Utilization

**RECOMMENDATION** ▶ MO 3b

Transmission flow limits can be an effective tool for managing loop flow on external systems, but results in underutilization of the grid and an overall loss in efficiency when the system is unconstrained. Market-to-market congestion management enhances the process by enabling higher levels of external flows and greater utilization of the transmission system. Rather than restricting external flows based on entitlement limits, the market-to-market process allows equal and unimpeded access to the full capability of the combined transmission system for both markets. If congestion occurs, the market operators coordinate to determine the least-cost redispatch solution and the market that can relieve the constraint most cost-effectively does so through market redispatch. Flow entitlements are used in the market-to-market redispatch process after the fact to allocate redispatch costs.

Market-to-market redispatch produces substantial efficiency and reliability benefits, but is a major undertaking, requiring not only agreement on settlement rules and flow entitlements, but development and implementation of a host of enabling tools and procedures. The process must be fully integrated into the operating, dispatch and settlement systems in both markets. Use of market-to-market congestion management affects market outcomes and must be incorporated into the tariffs of all involved market operators. In the West, development of the process will require engagement of all involved transmission service providers, operators, and balancing authorities.

As detailed in Grid Strategies' prior seams report, market-to-market congestion management is a valuable but imperfect seams mitigation tool.[25] The process can be administratively challenging. Although much of the process is automated, market operators must continuously evaluate grid conditions, identify potential new transmission elements ("flowgates") eligible for coordination, and activate the flowgates in the market software. Independent Market Monitor analysis of the process found that administrative errors are not uncommon and in 2022 resulted in excess congestion costs of $119 million at the MISO-SPP seam. The Market Monitor also found that inaccurate modeling assumptions and software limitations further contributed to market-to-market redispatch efficiency losses. Finally, ongoing operation requires human judgment and market operators have not always agreed upon whether or when the process should be invoked for some flowgates.

Market-to-market congestion management is a significant improvement relative to flow limits, but it is not a panacea and does not eliminate the negative impact of seams. In the West, it will be important to determine the feasibility of market-to-market congestion management prior to implementation of the ECC, as well as the additional complexity involved given the division of operational responsibility and multiple tariffs governing system access and use.

## Ensuring Efficient Market Interface Prices

**RECOMMENDATIONS ▶ MO 1, MO 2**

Interface prices are essential for incentivizing market imports and exports and hence promoting efficient transfers between markets. Interface prices on either side of a market seam determine the profit opportunity available to participants wishing to transfer energy between markets and hence drive market behavior. The interface price is a proxy, intended to reflect the marginal value of either injecting energy into or withdrawing energy from the market. To the extent that

25 Grid Strategies LLC, *Market Configuration Matters: Effects of Market Choices on Consumers in the Northwest US*, pp. 14-16, June 2024.

interface prices accurately reflect the marginal value of energy, they provide an incentive for participants to engage in efficient transfers.

There is no industry standard or broadly agreed-upon method for establishing interface prices. Different markets have taken different approaches over time and in the case of SPP, PJM and MISO, all are working to address identified issues with their current methodologies. Experience in those markets, including analysis and recommendations by the PJM and MISO Market Monitors,[26] offers insights that may be useful as CAISO and SPP define interface prices for EDAM, Markets+, and SPP's RTO expansion.

Interface pricing in the West will be complicated by market configuration. RTO markets typically include a single interface price for each external region. This may not be possible in the West given the separate Markets+ Northwest and Markets+ South subregions. An import into Markets+ from EDAM, for example, will have a different value if the destination is Washington or Arizona. Use of a single interface price for Markets+ would provide an inaccurate price signal, encouraging inefficient transfers and discouraging efficient transfers. It would also likely result in a cost shift as transfers between Markets+ subregions would not incur congestion reflective of their flow impact on the external grid.

While it may be necessary in the West, the use of multiple interface prices raises gaming and market manipulation concerns by creating incentives for "sham" scheduling to intentionally misidentify the source of a transfer. Such activity produces inefficient market outcomes including price distortions and can contribute to the underfunding of congestion revenue rights. The PJM Market Monitor has evaluated the consequences of sham scheduling in PJM and recommended rules to require accurate identification of physical sources and sinks and implementation of procedures to validate source and sink accuracy.[27] Depending on market configuration and how interface prices are defined, similar rules and processes may be needed in the West.

## Reducing Barriers to Trade

**RECOMMENDATION** ▶ MO 4a-b

Independently cleared subregional markets will produce a less efficient regional resource commitment and dispatch than would a single market. In theory, efficiency losses could be mitigated through market trading with participant-initiated transfers between markets. Price differences between markets provide an incentive for participants to trade across the market seam. In practice, although the incentive exists, market seams create barriers to trade that reduce opportunities for, and the effectiveness of, participant attempts to arbitrage price differences between markets. Transactional barriers include inflexible trading mechanisms, lack of price transparency, price volatility, inefficient interface pricing, lack of hedging opportunities, transaction costs, time delays between scheduling and clearing windows, and misaligned market timelines.

26 Potomac Economics, 2023 State of the Market Report for the MISO Electricity Markets, Section VII C, June 2024; Monitoring Analytics, LLC, *2024 State of the Market Report for PJM, Section 9*, March 13, 2025.

27 Monitoring Analytics, LLC, *2024 State of the Market Report for PJM*, p. 470, March 13, 2025.

While some of the above issues can be partially mitigated through tariff and market design enhancements, there are additional sources of market friction that are not within the control of the market operators. NREL has found, for example, that inconsistent calculation of available transfer capacity, failure to update flow limits, and inaccurate transmission system modeling can all negatively impact inter-market transfers.[28] The use of path-based processes to grant transmission service limits transmission service availability below the physical capability of the system, imposing an additional barrier to efficient transfers between markets.

Trading outcomes in the East have shown the inefficiency created by market seams and the limits of participant attempts to arbitrage that inefficiency through inter-market trades. The PJM Market Monitor reported that in 2024, real-time flows were consistent with the market price differential only 55.2% of the time at the PJM/MISO interface and only slightly better at 62.7% at the NYISO-PJM seam.[29] Despite more than 20 years of trial and error, participants have been unable to find ways to reliably arbitrage market price differences. And while steps have been taken to encourage inter-market trading, the efficiency impact of market barriers is significant and the ability to mitigate that impact by participant-initiated transfers is limited.

Barriers to trade and the resulting suppression of inter-regional transfers have consequences beyond short-term efficiency losses. Inability to engage in real-time dispatchable import/export transactions reduces overall system flexibility and limits the ability to dynamically balance large portfolios of variable resources. The lack of real-time dispatchable import/export transactions also inhibits the ability to respond to energy emergencies. Finally, financial and delivery risk limit opportunities for long-term resource procurement. For all these reasons, it is essential that steps be taken to increase trading opportunities and reduce barriers to trade.

Market transfers can be encouraged by creating flexible options for participants to trade between markets. RTO markets typically offer day-ahead price-responsive imports and exports. Sources can be individual generators or nonspecific “spot market” energy, the latter being particularly beneficial for trading between markets as it encourages participation by traders willing to engage in purely financial transactions. CAISO markets offer this option through

28 National Renewable Energy Laboratory, *Barriers and Opportunities to Realize the System Value of Interregional Transmission*, p. vii-viii, June 2024.
29 Monitoring Analytics, LLC, *2024 State of the Market Report for PJM*, p. 469, March 13, 2025

intertie bidding, but WEIM entities must proactively enable intertie bidding in their area. In the two EDAM conforming OATT filings made thus far, neither transmission provider has proposed to enable intertie bidding.[30] This will significantly limit transfers between markets as, absent intertie bidding, only individual generators may offer to import or export across the seam on a price-responsive basis. Markets+ stakeholders are presently evaluating options to enable non-source or sink specific exports and imports to facilitate seams transactions.[31] Enabling intertie bidding in both EDAM and Markets+ would be a significant improvement and enhance seams efficiency.

Real-time dispatchable transactions between markets could represent a further evolution in seams trading. While intertie bidding is a step forward, because intertie bids clear and are scheduled on an hourly basis, there is still a significant opportunity for improvement. Available potential models for the West for intra-hour real-time trading include Real-Time Dispatchable Transactions (RTDT) as proposed for SPP RTO expansion or Coordinated Transaction Scheduling (CTS) currently used in NYISO, MISO, and PJM.

The need to preschedule transfers requires market participants to commit to a transaction before knowing if it will be profitable. Prices move independently in each market and participants must submit an import/export schedule based on their forecast of future prices. CTS attempts to improve the situation by enabling market participants to submit offers to schedule imports and exports using a market operator forecast of the interface price spread. Bids are compared to the forecast and cleared when the forecast suggests the transaction will be profitable. CTS was hoped to represent a significant opportunity for market participants, but RTO price forecasts have not proven to be more accurate than participant forecasts, and CTS transactions lose money in a significant portion of hours. As a result, the option is not widely used. The MISO Market Monitor reported that in 2023, CTS cleared only 30 MW on an hourly average basis.

Although CTS performance overall has been poor at the MISO-PJM and NYISO-PJM seams, market design enhancements have been identified that could improve performance. MISO Market Monitor analysis has shown that improved forecast accuracy and more frequent clearing would substantially improve CTS performance at the PJM-MISO seam. Based on simulation of a revised CTS product, the Market Monitor found that uneconomic transfers would decline by half and that trade profitability would increase from a 2023 actual value of $237,000 to $41 million. Total market efficiency gains in the simulation were nearly $100 million. Similar analysis found that the revised CTS would deliver more than $34 million if implemented at the MISO-SPP seam, where CTS has not yet been deployed. These findings suggest that although the benefit is modest, CTS is worth evaluating in the West.

SPP RTO's proposed Real-Time Dispatchable Transactions (RTDT) offer a promising model for flexible scheduling between markets. RTDT would enable participants to submit price-responsive bids and offers to be cleared on a 5-minute basis in the real-time market. This would be a substantial improvement over CTS. Applicability will be limited by the need to

30 PacifiCorp, *Revisions to PacifiCorp OATT to Implement the Extended Day-Ahead Market, ER25-00951-000*, January 16, 2025; Portland General Electric Company, *Revisions to the Portland General Electric OATT to Implement the Extended Day-Ahead Market, ER25-01868-000*, April 3, 2025.

31 SPP Markets+ Seams Workgroup "Markets+ Interchange Transaction Centroids" whitepaper, July 2025.

pre-schedule and pay for transmission service eligible for dynamic scheduling. Success of the product, as with CTS, requires that markets on both sides of the seam adopt the product and coordinate its use in real-time. Markets+ does not currently include real-time dispatchable import/export transactions but has identified the product as a potential future enhancement.[32] EDAM does not include a comparable product. Although it would be limited in use based on technical requirements, RTDT would provide additional flexibility for participants and encourage transactions across market seams.

### Internalizing Interchange Optimization

**RECOMMENDATION** ▶ MO 4c

A final option to facilitate economic transfers between regions is to internalize the decision within routine market operations. Under this approach, optimization of market transfers is added to the objective function of the market clearing process. Rather than relying on participants to initiate transfers, under an interchange optimization approach, market operators would coordinate flows to maximize economic transfers between markets. Interchange optimization would not displace participant trading but would supplement and clear residual economic transfers remaining after participant transactions. This has not been attempted in other markets, although ISO-NE and NYISO have developed a proposed mechanism.

Recent studies have highlighted the potential benefits of interchange optimization and interest has been expressed in pursuing the concept in some markets. A Brattle Group study estimated that 20% to 30% of the value of inter-regional transmission in SPP, MISO and PJM is lost due to the inability of participants to efficiently trade between markets.[33] NREL has identified interchange optimization as a mechanism to remove trade barriers and unlock the value of inter-regional transmission.[34] Similarly, the Northeast States Collaborative on Interregional Transmission, in their most recent action plan, calls for Northeast RTOs to pursue interchange optimization as a means of reducing barriers to trade and increasing the value of inter-regional transmission.[35] SPP is actively evaluating interchange optimization as a means to improve market interchange efficiency at the SPP-MISO seam.[36] The PJM Market Monitor has recommended that PJM pursue interchange optimization to address inefficient seams trading.[37] The concept is promising, and additional research should be encouraged to determine if some form of interchange optimization is a practical option to improve seams efficiency in the West.

32 Markets+ Market Seams Working Group, *Seams Strategy and Roadmap*, p. 6, April 11, 2025.

33 Brattle Group and Willkie Farr & Gallagher LLP, *The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission*, p. 27, October 2023.

34 National Renewable Energy Laboratory, *Barriers and Opportunities to Realize the System Value of Interregional Transmission*, p. 37, June 2024.

35 Northeast States Collaborative on Interregional Transmission, *Strategic Action Plan*, p. 11, April 28, 2025.

36 SPP, *Inter-Market Optimization Framework, Presentation to the Strategic Planning Committee*, October 2024.

37 Monitoring Analytics, LLC, *2025 State of the Market Report for PJM*, p. 470, March 13, 2025.

# RECOMMENDATIONS

The impacts of market seams in the West will be experienced in nearly every part of the industry, by market operators, grid operators, resource and transmission planners, operating and capacity reserve sharing program participants, and market participants. Many entities will have a role in identifying and managing the adverse impacts of seams. The recommendations below are divided into categories by the entities most impacted and responsible for addressing the issue. In most cases, other entities will also be directly involved in the process of developing solutions. When establishing priorities and timeline, it will be important to consider EDAM and Markets+ launch timing and how membership in each market will change over time.

**(BA) Balancing Authorities:**

- BA 1 Evaluate, revise or negotiate new BA-BA and BA-Market Operator coordination agreements to ensure compatibility with new markets and address new seams.
- BA 2 Evaluate performance and financial implications of market seams for reserve sharing arrangements.

**(MO) Market Operators:**

- MO 1 Establish interface prices.
- MO 2 Develop rules and procedures for interchange source/sink monitoring and validation.
- MO 3 Develop congestion management protocols and incorporate into day-ahead and real-time markets. Pending completion of ECC effort, simplified methods should be considered leveraging existing congestion management mechanisms:
  a. Market-to-nonmarket to limit flows on external non-market systems.
  b. Market-to-market for market-based congestion management with external markets.
- MO 4 Evaluate and consider implementing:
  a. Intertie bidding in day-ahead to enable non-point-specific supply offers or demand bids.
  b. Enhanced real-time dispatchable trading options, including Coordinated Transaction Scheduling and Real-Time Dispatchable Transactions as proposed for SPP RTO.
  c. Interchange optimization.

**(NAESB) North American Energy Standards Board:**

- NAESB 1 Complete efforts under Western Interconnection Congestion Management Working Group to develop new interconnection-wide congestion management for the Western Interconnection (Western Interconnection Loading Relief Business Practice Standard).

**(RC) Reliability Coordinators:**

- RC 1 Complete development and lead implementation of NAESB ECC standard for congestion management in the West. Ideally, this will be done prior to the need for market-to-market congestion management.

- RC 2 Evaluate and revise RC-RC coordination agreements to ensure compatibility with new markets and address new seams. New agreements may be needed, for example, between BC Hydro and SPP RC or between the Alberta Electric System Operator RC and SPP RC.
- RC 3 Work with Balancing Authorities and Market Operators to evaluate and update emergency operating procedures.

**(TSC) Transmission Customers and Market Participants:**

- TSC 1 Evaluate existing contractual arrangements to identify potential changes to comply with new market scheduling requirements or address financial exposure if the contract requires delivery across a market seam.
- TSC 2 Update resource planning processes and tools to reflect realistic assumptions about availability and cost of imports.
- TSC 3 Evaluate performance and financial implications of market seams for Western Resource Adequacy Program (WRAP) energy deployments.

**(TP) Transmission Planners:**

- TP 1 Include accurate modeling of market configuration and economic hurdles to inter-market transfers.

**(TSP) Transmission Service Providers:**

- TSP 1 Convert from path-based Area Interchange to flow-based Flowgate methodology for calculating available transmission. This will be a necessary step for the adoption of market-to-market congestion management.

**(WPP) Western Power Pool:**

- WPP 1 Evaluate NWPP Reserve Sharing Program performance obligations and financial settlements in light of recently approved tariffs for EDAM and Markets+.
- WPP 2 Evaluate WRAP terms and performance obligations in light of market tariffs. When developing operating protocols, consider the financial implications of scheduling resources across market seams.

# Grid Strategies

gridstrategiesllc.com

info@gridstrategiesllc.com

Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in transmission and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations, the North American Electric Reliability Corporation, Congressional committees, the administration, and various stakeholders.