The Day After Day-Aheads:
How Greater Regional Coordination Could Improve Project Development and Commercialization in the Western Interconnection

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I. Executive Summary

The West's decentralized model of electric operations and market activity has delivered reliable electricity at comparatively low rates over its long history. Private utilities, federal entities, and public power providers have operated their own largely independent systems and relied on bilateral contracts to buy and sell power across a patchwork of transmission providers and balancing authorities (BAs). This model has proven resilient and adaptable, but its inefficiencies have become increasingly problematic in recent years. The patchwork model introduces inefficiencies that constrain energy suppliers from reaching willing buyers to execute competitive transactions, and these constraints raise overall costs for consumers. This paper will recommend a set of solutions to be considered as next steps in the continued expansion of regional coordination and collaboration in the West.

At present, electricity demand is growing faster than it has in decades. States, utilities, and corporate buyers are pursuing ambitious clean energy goals, aging generators are being retired or repurposed, and grid operators face increasing challenges to maintain reliability. Transmission systems are strained, electricity costs are rising, and policymakers face growing pressure to ensure customers receive affordable and reliable power.

In response to these pressures, reforms have been introduced in the West that have centralized real-time market functions, delivering substantial economic, environmental, and reliability benefits.[1] This first set of relatively recent reforms included creation of two real-time markets in the West: the Western Energy Imbalance Market (WEIM) operated by the California Independent System Operator (CAISO), and the Western Energy Imbalance Service (WEIS) operated by the Southwest Power Pool (SPP).[2] The next wave of reforms included creation of two day-ahead electricity markets: CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+.[3] In addition, some Western utilities are participating in the Western Resource Adequacy Program (WRAP), which is expected to move into a binding phase in less than two years, and other load-serving entities are exploring launching a second regional resource adequacy (RA) program.[4]

Although these reforms are likely to provide additional benefits to wholesale electricity transactions in the West, the modern challenges facing the system are amplifying the need

[1] For purposes of this paper a "real-time market" is a wholesale electricity market which economically dispatches resources to match changes in supply and demand in 5- to 15-minute intervals. A "day-ahead market" is a financially binding wholesale electricity market which identifies and schedules the most cost-effective generation resources to serve load on an hourly basis for the next operating day.

[2] Note that the WEIS was retired on April 1, 2026 as the majority of that footprint joined SPP's Regional Transmission Organization (RTO).

[3] Additionally, a group of utilities and transmission owners joined SPP's RTO via the "RTO Expansion" into the Western Interconnection that became operational in April 2026. While this is a significant change for that area of the West, it represents a relatively minor quantity of West-wide load and is not the focus of this paper, which is evaluating more incremental reforms that may be implemented more broadly in the West.

[4] Information on this new program, whose governing body could be the Regional Organization for Western Energy (ROWE), is available at: https://rowesternenergy.org/regional-resource-adequacy/.

to bring new, cost-effective generation resources online faster than the reforms are materializing. Further improvements and greater regional coordination could provide additional benefits during this period of transition.

The West, outside of the footprint of CAISO and SPP, continues to lack several core functions – primarily related to transmission system operations – that Regional Transmission Organizations (RTOs) provide elsewhere in the U.S. and that could improve the resiliency and affordability of energy in the West. These functions (which could also be called operational features) include: consolidated transmission system operations and control, a standardized generator interconnection process, durable and complete electricity markets, a regional RA paradigm that applies consistently across the full footprint, and regional transmission planning administered by a centralized and neutral party.[5]

The absence of these functions in the West has resulted in barriers for project development and, particularly, the commercial process by which developers identify viable sites for electricity resource development, secure buyers, and sign contracts, which is the focus of this paper. Under the current structure, generation developers in the West face requirements to secure and pay for expensive and limited transmission service (or their customers must do so), inconsistent interconnection rules, fewer off-takers and counterparties, and relatively opaque pricing. These barriers can increase development costs, which in turn raises costs for energy buyers, including utilities and their ratepayers. Buyers also have fewer competitive supply options than they would under more coordinated regional arrangements, potentially leading to further increases in costs and development risks.

The West could collaboratively pursue the development of these missing functions to help mitigate upward pressure on electricity costs. Such functions could be implemented through the creation of an RTO, but other, faster, incremental paths also exist. It is also worth acknowledging that – outside of a small area that recently joined SPP – full RTO development in the West has not succeeded as a single large step, despite being explored multiple times over more than 30 years. And RTOs in other regions of the country have also experienced their own set of issues and disputes, which appear to be increasing in recent years.[6] Thus, while efforts to explore RTO development in the West may continue, for the time being this paper anticipates the West pursuing these functions through incremental,

[5] An additional function would be the consolidation of Balancing Authorities, which may provide a host of benefits to the West. However, this function is not a primary focus of this paper, given its limited impact on project development relative to the functions that are discussed herein.

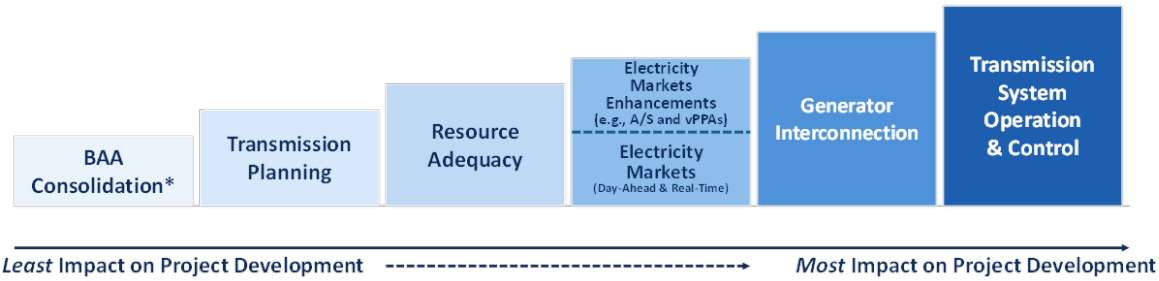
[6] For instance, there have been recent challenges with PJM's Minimum Offer Price Rule (MOPR), which were seen as conflicting with state clean energy procurement rules. There are also challenges with governance-issues across multiple RTOs. SPP's governance process was successfully challenged at FERC, ultimately requiring SPP to enable participation of non-incumbents without a burdensome exit fee. But participation challenges remain, in particular, because of the time required to participate, which becomes a barrier for many parties. FERC Chair Laura Swett recently raised concerns about PJM's governance (*see* Comments at PJM Annual Meeting (May 12, 2026), available at: https://www.ferc.gov/news-events/news/chairman-laura-swetts-comments-pjms-annual-meeting-baltimore-md-0).

coordinated services provided or facilitated by able and willing regional entities, including wholesale market operators such as CAISO,[7] or SPP, or other regional organizations such as the Western Power Pool (WPP), which administers the WRAP and other coordination programs.

The key functions and processes critical to project development that could be better coordinated in the West are shown in Figure 1. The graph indicates a rough order of their expected impact on the project development process (from least impactful to most impactful). However, this figure does not imply that subsequent regional reform efforts should move from left to right, nor right to left.

Figure 1

Relative Impact of More Coordinated Functionality on Project Development



*Given its limited impact on project development, BAA consolidation is only briefly mentioned in this paper (and is not given its own section within the text of the document).

This paper is written from the supply-side perspective of developing and commercializing resources – including contracting, financing, and construction – under existing commercial and regulatory constructs. It describes key stages of the development cycle for new power plants and energy storage facilities and explains how that cycle differs in the West. The paper also describes how a more coordinated approach could impact project developers (electricity suppliers), electricity buyers, and end-use customers. Tables 1.1 – 1.5, which follow this Executive Summary, summarize how the functions in Figure 1 have historically worked in the West, what will change (if anything) as day-ahead markets are implemented, and what a more coordinated approach could entail, including potential impacts on energy buyers and generation developers.

[7] Note that, following the recent passage of AB 825 in California, the ROWE has been incorporated and will undergo further development in order to oversee the market functions offered by CAISO. It is likely that it would be this new organization, rather than CAISO, that would be best situated to offer the new, additional services/functions discussed in this paper, given its anticipated independent governance structure.

Section II of the paper describes the current status of regional coordination in the West and the elements of project development that independent power producers (IPPs) must secure to commercialize a project. Section III of the paper provides a more detailed description of the functions summarized in Figure 1 and Tables 1.1 – 1.5. The final section offers a conclusion.

This paper does not take a position on whether these services should ultimately be bundled in a full RTO or if they should be offered by a single provider or multiple entities, both of which have advantages and disadvantages. Instead, it explains how additional efficiencies in project development are available if the region adopts a larger set of coordination functions. The paper is agnostic about the particular pathway. Policymakers and regulators evaluating future reforms should focus on the functions (or operational features) themselves, rather than solely on the institutional form through which they might be provided.

Note: For readers with more limited time, we have inserted the function tables on the next few pages in order to summarize the core comparative analysis of the paper. Other readers can refer back to these tables after reading the subsequent sections.

Table 1.1 Overview of Key Electric System Functions in the West and in a More Coordinated System

Transmission System Operation & Control: Controlling and optimizing the flow of electricity over the high-voltage network to manage congestion and maintain reliability

Historical Western Approach	With a Day-Ahead Market	A More Coordinated Approach & its Impacts
Transmission system is fragmented and operated based on contractual paths that are a proxy for, but ultimately divorced from, physical realities. Developers (or the buyers of their project's output) must acquire transmission service from each transmission provider along the contractual route from source to sink. This leads to "pancaking" (or stacking) of transmission rates for purchases that must be wheeled across multiple transmission systems. Utility solicitations for new generation often require transmission service (or a path to it) for bidders to be successful.	Transmission system remains fragmented. Rate pancaking may be reduced or eliminated for transactions in a day-ahead market. However, markets continue to require or strongly encourage contract-path transmission service, leaving many of the historical barriers in place.	Transmission tariffs are consolidated, and functional control of transmission facilities is transferred to a centralized market operator. Developers and buyers do not need transmission service along contract paths. Instead, generation dispatch optimizes the flow of power across the system according to physics and the system's capabilities. Market prices reveal where the grid is congested and promote transmission development to relieve congestion. Developers & buyers can hedge their exposure to congestion pricing and curtailment using Financial Transmission Rights (FTRs) instead of reserving transmission service. De-pancaking results from a negotiated cost allocation methodology for the footprint of the consolidated transmission facilities. **Impacts:** Reduced transmission barriers increase options (locations and configurations) for new generation, drive development to more beneficial locations, and promote competition. Without transmission rate pancaking, power delivery costs can generally be reduced as buyers can access more cost-effective resources.

Table 1.2 Overview of Key Electric System Functions in the West and in a More Coordinated System

Generator Interconnection: Studying proposed resources and determining what transmission system upgrades are needed to safely interconnect them to the Bulk Electric System

Historical Western Approach	With a Day-Ahead Market	A More Coordinated Approach & its Impacts
Each transmission provider manages its own generator interconnection queue (or queues) according to its own unique tariff and study processes.	No change. Interconnection queues will still be managed by each individual transmission provider using its own unique processes.	One consistent and consolidated generator interconnection process is generally used across a broad region. It relies on standardized rules, timelines, and requirements that are set by a single service provider/market operator's tariff. **Impacts:** Developers are exposed to less risk and uncertainty when navigating a standardized process. Cost allocation for interconnection upgrades can also be more transparent and fair when done by an impartial entity (increasing competition and leading to lower costs for consumers). "Self-build" solutions for interconnection and other transmission-related facilities can be enabled more widely. Interconnection-related favoritism toward generation projects owned by the transmission owner becomes rarer.

Table 1.3 Overview of Key Electric System Functions in the West and in a More Coordinated System

Electricity Markets: Dispatching generation and balancing supply and demand for both the day-ahead and real-time timescales

Historical Western Approach	With a Day-Ahead Market	A More Coordinated Approach & its Impacts
Utilities balance their load using the resources in their local balancing area. Imports and exports between balancing areas are based on bilateral agreements. Real-time organized markets have increased optimization between entities in the same market footprint, generally covering around 5 percent of total transaction volumes. Publicly available day-ahead energy prices are limited to a few trading hubs. Real-time markets have increased price transparency but reflect only a small volume of transactions and can be influenced by administrative constraints.	The market optimization supports efficient procurement of resources across balancing authorities that are participating in the same day-ahead market. Day-ahead prices are public, and include a higher volume of transactions but, as currently designed, EDAM and Markets+ will not reflect the costs of most ancillary services.	All energy and ancillary services (real-time and day-ahead) are procured through a centralized market that dispatches generation to meet demand based on economic offers. The markets are highly liquid and support a broader variety of buyers and sellers. The prices for all transactions of energy and ancillary services are public and are formed consistently based on physical system limitations. **Impacts:** Developers can use historical market prices to determine where new resources will provide the greatest value. This optimizes resource development for the system. Because of the durable market structure, electricity buyers have more contracting options, such as innovative deals like virtual power purchase agreements, which leads to more buyers for projects in development.

Table 1.4 Overview of Key Electric System Functions in the West and in a More Coordinated System

Resource Adequacy: Ensuring that enough capacity is developed and available to reliably meet projected peak demand plus required reserve margins

Historical Western Approach	With a Day-Ahead Market	A More Coordinated Approach & its Impacts
Investor-owned utilities are obligated to procure enough capacity to satisfy the RA obligations that their state regulators set for them.	Load Serving Entities, including investor-owned utilities, are still required to satisfy the RA obligations that their regulators set (often through a planning reserve margin in an Integrated Resource Plan). Some may participate in a joint RA program as part of their obligations for day-ahead market participation, due to state regulations, or simply on a voluntary basis.	The RA program manager or service provider sets the RA obligations and, generally, the method of counting different resources toward those obligations. Each utility then procures enough resources to meet that obligation through self-supply, bilateral transactions, or a voluntary region-wide market-based mechanism to procure capacity. "RA products" become relatively fungible across states and across program and market seams. Utilities must also comply with the relevant state policies, including potential associated state oversight of a regional program. **Impacts:** Developers have more options for securing RA payments for their resources because there is a market for RA contributions. This increases competition while maintaining grid reliability. Overall RA requirements for buyers may also be reduced as a result of efficiently and effectively sharing resources across the region, providing benefits to customers.

Table 1.5 Overview of Key Electric System Functions in the West and in a More Coordinated System

Transmission Planning and Cost Allocation: Conducting long-term transmission planning studies to identify and then coordinate transmission that supports reliability, cost efficiency, and public policy goals

Historical Western Approach	With a Day-Ahead Market	A More Coordinated Approach & its Impacts
Each utility plans for its own transmission system using its own local planning process. Regional planning is ostensibly conducted by NorthernGrid and WestConnect, but they tend only to aggregate local plans and are largely viewed as ineffective at advancing transmission. Regional transmission planning remains largely disjointed. Non-jurisdictional transmission providers are not obligated to participate in mandatory cost allocation processes. Voluntary (non-regulatory) regional initiatives, like WestTEC, provide informational value.	No change, though the nodal prices from a day-ahead market provide valuable information about transmission constraints. Transmission planning will still be handled by local and regional entities and bilateral partnerships, just as it has been historically.	An independent entity evaluates the transmission needs of the region based on reliability, economic, and policy criteria, and with input from utilities and stakeholders. Many projects are open to competitive solicitation to select a developer to most cost-effectively build projects to meet identified needs. Costs for regional facilities are allocated across the region according to the tariff. **Impacts:** Comprehensive transmission planning by an independent entity across a larger region and the opening of some projects for competitive solicitation can decrease system costs for all participants. It can also identify transmission expansions that unlock low-cost resources in remote areas.

II. Introduction & Overview of Project Development

The U.S. electricity sector has consistently evolved to address changing circumstances over the last century. Early in the 20th century, vertically integrated utilities held exclusive rights to generate, transmit, and distribute power. Over time, federal and state policymakers introduced new forms of competition. Competition enabled IPPs and power marketers to sell into wholesale electricity markets, and in some cases created more opportunities for non-incumbent electricity service providers to serve loads (i.e., enabled different types of retail electric choice). By the late 1990s, the Federal Energy Regulatory Commission (FERC) encouraged the creation of RTOs and Independent System Operators (ISOs) to operate transmission systems and wholesale markets across broad regions.[8] These organizations have created a host of benefits in the areas where they operate, while also facing their own set of challenges.

Today, about two-thirds of U.S. retail electricity sales occur in areas served by RTOs/ISOs.[9] These regions have independent transmission system operation, regional transmission planning, and transparent wholesale markets which enable a range of different electric resource contracting structures facilitating generation project development in those regions. Similar reforms have been successfully implemented in Canada and Europe.

The other one-third of the U.S. remains outside the RTO/ISO model. This includes most of the West,[10] which has for a variety of reasons evolved in a unique way: instead of having an RTO/ISO, it relies on a more decentralized structure that has, over time, sought to incorporate certain, discrete initiatives that are features of RTO/ISOs elsewhere in the country. Several attempts in the West to form an RTO model over the last thirty years were never completed.[11]

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[8] RTOs and ISOs have little practical difference between them, though an RTO generally covers a larger set of states. But the terms are used interchangeably in this paper to reflect a large-scale independent grid operator. More information on the regulatory origins of ISOs and RTOs, and what that history suggests about further Western regional initiatives, is contained in an Appendix.

[9] FERC, *Energy Markets* (Aug. 18, 2025), available at: https://www.ferc.gov/opp/energy-markets.

[10] For the sake of convenience, references to "the West" or "Western" in the paper, unless otherwise noted, exclude parts of California's grid (the part controlled by CAISO) and the eastern segments of the Western Interconnection that recently joined SPP's RTO.

[11] Public Generating Pool's 2021 report, *Organized Market Retrospective: A Review of Organized Market Efforts in the West*, provides a useful recent summary of those efforts, from a Pacific Northwest perspective (available at: https://static1.squarespace.com/static/5e9fc98ab8d9586057ba8496/t/618e659a11c58b644b0cfaea/1636722079829/PGP+Organized+Market+Retrospective+Full+Report.pdf). For the most part, this primer does not focus on the unique opportunities and challenges of having two large federal power marketing administrations (PMAs) in the West, the Bonneville Power Administration (BPA) and Western Area Power Administration (WAPA). The PMAs, and BPA in particular as the dominant transmission provider and largest single power supplier in the Northwest, have been integral to both successful regional coordination and failed efforts at doing more. With a few exceptions, this paper does not dwell on the ongoing reality that non-FERC jurisdictional entities like BPA and WAPA can breathe life into regional initiatives and attract critical masses of power sector participants. Conversely, they can be sources of significant disagreement and divergence, as well as acutely slow respondents to some customer requests for service.

Today the West has nearly 40 BAs responsible for ensuring reliable operations, even more transmission providers with individual tariffs and control of their portions of the transmission system, and a market system that primarily relies on bilateral transactions for long-term power sales and purchases. The West implemented organized real-time markets more than a decade ago, which provide significant benefits across these footprints by better coordinating and optimizing the use of available electric resources within the operating hour.

Until recently, the existing structure of the West has worked relatively well in some respects. Western electricity rates have historically been among the lowest in the country, which is one key reason that the pressure to form an RTO has been less prevalent than in other regions. The Western grid has also remained largely reliable across vast geographies. But new stresses have emerged and will require the West to innovate and seek more coordinated and efficient functions.

To help address these needs, the region has recently taken meaningful steps towards establishing better coordination. Two key recent improvements include:

- **Day-ahead markets** – EDAM became operational in May 2026 and Markets+ is slated to begin operations with the initial wave of participants in 2027.[12] They will allow economic optimization of electrical supply and demand in the day-ahead timeframe, committing resources more efficiently across large multi-BA footprints to meet the next day's expected demand. These markets are expected to replace much of the "bilateral" trading that occurs for day-ahead (or even weekly/monthly) transactions in the West today. But these markets will be built on top of the existing, patchwork Western transmission framework, creating unique challenges and potentially limiting their ability to fully optimize the transmission network. These limitations will, in turn, limit the improvements in resource development experienced in regions with deeper levels of regional coordination.
- **Regional RA programs** – WRAP created a common framework, within its footprint, for quantifying how much capacity various types of resources contribute to peak system needs. WRAP also created a framework for ensuring its participants have sufficient capacity secured to jointly meet peak demand and achieve a defined level of system reliability. Recently, the anticipated footprint of WRAP shrank after a number of parties (including competitive retail suppliers that are members of NIPPC) indicated their intent to officially withdraw in Winter 2027/28 before the program and its associated deficiency penalties become binding.[13] A number of the entities that withdrew from WRAP have begun discussing and proposing an EDAM

[12] EDAM became operational on May 1, 2026 in CAISO and PacifiCorp footprints and is slated for additional participants to join later in 2026 and in future years. Markets+' first wave of participants is expected to begin operations in October 2027 and another set of participants will join in October 2028.

[13] WRAP participants have decreased recently with the announced withdrawal of NV Energy, PacifiCorp, Portland General Electric, Public Service Company of New Mexico (PNM), and Calpine Solutions, among others. The remaining WRAP footprint – at this time – remains relatively large and covers Markets+ participants and some entities expected to join EDAM, such as Idaho Power.

footprint-focused alternative RA program. As described to date, this program would bear a resemblance to WRAP in some regards.

The efforts underway in the West represent real progress to coordinate regionally and deliver key benefits. Soon, most real-time and day-ahead transactions in the West will take place through organized markets, not purely bilateral deals. And WRAP (and a potential alternative regional RA program for entities participating in EDAM) will provide a foundation across part of the Western Interconnection's footprint for ensuring sufficient resources exist to meet an acceptable level of potential reliability events and allow for sharing of these resources among participants.

But despite this forward progress, important gaps remain, especially for successful – lowest cost – electricity project development and delivery to customers. The initiatives underway in the West **do not address the principal barriers** that make project development more difficult in the West today. For example, the pending, near-term reforms do not eliminate the need for firm transmission service for long-term resource contracting, provide independent regional transmission planning, harmonize interconnection processes, nor consolidate transmission operations and reliability responsibilities into a single transmission and reliability operator. All of these functions could provide additional benefits for project developers and electricity buyers. Thus, **the result of near-term regional initiatives in the West (day-ahead markets, regional RA programs, and WestTEC) is that there will be improved short-term markets but still few of the long-term, independent, structural functions that support the development of the most cost-effective/efficient new resources in other regions.**

Given that the latest developments in the West leave additional beneficial functions still on the table, we propose considering what functions should be added as the West explores the next regional opportunities. This paper focuses on how those additional functions could affect the process of project development and, thereby, offer benefits to electricity suppliers, buyers, and end-use customers across the West.

While this paper focuses on the regional electric grid and market functions that are typically bundled together with an RTO in other regions of the country, it does not simply advocate for the creation of an RTO in the West. NIPPC and Interwest recognize that the West is unique and, in part because of that uniqueness, has struggled for decades to successfully develop a wide-scale RTO-like entity. Instead, this paper focuses on the functions themselves and leaves aside the question of the appropriate provider(s) of these services and the appropriate corporate or organizational structures. The paper is largely an exercise in contrasting how project development happens in the West today versus how it happens in jurisdictions that have implemented greater coordination, particularly around transmission functions. While fundamental transmission functions are typically part of an RTO framework, they may be achieved outside that particular framework through a more "a la carte" model.

This paper focuses specifically on tools or functions that would improve the process by which developers identify commercially viable sites, secure off-takers, and bring projects

to market, which we refer to as **project development**. While the full project development lifecycle includes many steps, this paper is focused on the *commercial side,* which includes transmission viability, market access, and buyer contracting, and *not* on permitting or land use.

The term **"project development"** in this paper is defined as:

The process by which developers of new electric generation or storage resources identify commercially viable sites, secure buyers (off-takers) and financing, and sign contracts to deliver electricity to the grid.

This may be called "project origination" by some resource developers. But we are using the broader term "project development" given it is more widely understood. The term project development, when used in this paper, focuses specifically on the *commercial aspects* of project development: transmission system feasibility, pricing, and contracting. And, for purposes of this paper, it does not include land use, permitting, or environmental approvals, which are all part of successfully building a new project (but are not influenced by the availability of regional market functions/tools).

Project Development Overview

Across all regions of the country (those with and without RTOs), development by competitive (i.e., non-utility) suppliers of new generation and storage projects almost always requires an underlying long-term Power Purchase Agreement (PPA) or tolling agreement.[14] These long-term agreements are required to receive financing to construct the project. Typical off-takers are utilities, power marketers, or large end-use customers. The contracts can take a variety of structures, including tolling agreements, physical PPAs, or "virtual" or "financial" PPAs.[15] The specifics of the long-term contracts are not

[14] A tolling agreement is a form of contract, distinct from a PPA, that is often used for battery and other storage facilities, as well as natural gas generators. Under a tolling agreement, the plant/storage facility owner provides the physical facility, while the off-taker (toller) provides and pays for the fuel (e.g., natural gas or electricity) to be stored. In exchange, the off-taker pays a fee (called a toll) which usually covers the fixed and variable operating expenses plus a return. This paper focuses particularly on investor-owned utility and corporate off-takers because so much recent load growth and generation fleet turnover has been concentrated with those buyers. But consumer-owned utilities are an important segment of off-takers as well.

[15] Virtual PPAs are purely financial contracts between a power facility and a buyer that don't involve the buyer taking physical delivery of electricity. Under these agreements, which have generally only been viable in large quantities in RTO regions, the project sells electricity into the wholesale market at its nodal location. The seller and the buyer agree on a fixed "strike price" at a trading location. If the market price is below the strike price, the buyer pays the generator the difference. If the market price is above the strike price, the generator pays the buyer the extra amount.

particularly important to understand for purposes of this paper, though the virtual/financial PPA structure is typically only viable in regions with RTOs (or equivalent functions) because it relies on the long-term certainty of a highly liquid market for energy sales.

To secure a long-term contract with an off-taker, a project must meet a host of requirements, many of which involve transmission access and interconnection of the resource to the transmission grid. How those underlying transmission and interconnection requirements impact projects varies from region to region, which can have very different processes and requirements in many RTOs relative to the West. But regardless of where the project is being developed, transmission service, transmission operations, transmission planning, and how the reliability of the grid is maintained are important to successful project development. The various processes for securing transmission service in the West are complex, cumbersome, and costly, compared to other regions, and limit the geographic range of resource zones each utility can access.

As discussed more throughout this paper, the West may be able to add transmission-related functions onto its already planned reforms to improve the process of project development and facilitate a more competitive, efficient, and cost-effective power system. To orient the reader to the remainder of this paper, below we briefly outline some of the basic elements of successful project development in the non-RTO West and then in RTO regions. This comparison is not intended to suggest that RTOs are a panacea; they are instead aggregated here as a constructive counterpoint to the West.[16]

Project Development Basics in the non-RTO West:

- ***Determining Ideal Locations***[17]: Project developers must gather information on electricity prices at a given location, transmission congestion (real or contractual) that may impact that location, planned transmission facilities in the region, and other information relevant to determining the best location for projects from a plethora of different – and often incomplete – sources. Developers often must "guess" what locations would be best suited to off-takers' needs and to support efficient operation of the grid.
    - This creates more uncertainty for project developers in determining the best project locations for off-takers.

- ***Interconnection****:* Projects must seek the ability to interconnect from the transmission provider where their project is slated to plug into the grid. Thus, developers active in the West need to know and understand the nuances of various interconnection processes to develop their projects.

[16] As noted in the Executive Summary, RTOs have experienced their own sets of challenges and issues, with particular concerns raised in recent years around overall governance and how RTOs respect state prerogatives.

[17] Note that project developers also look at land-use, permitting, and environmental factors as part of determining project locations. But this paper is not focused on that aspect of project development, as it is not part of the commercial origination process and not generally affected by the electricity system functions at play in a given region.

- Because there are approximately 60 different transmission providers across the Western Interconnection, simply determining the appropriate party to seek interconnection from can sometimes be a challenge for project developers in the West. Furthermore, each transmission operator may have slightly different rules and procedures that govern interconnection to its system.
- Rules about a developer "self-building" interconnection upgrades on the transmission operator's system vary widely.
- Entities performing interconnection studies and granting requests for interconnection service may have some level of self-interest in performing studies and implementing the process, including how the process feeds into the same entity's solicitations (request for proposals or "RFPs") for new resources.

- ***Transmission****:* Projects developed in the West must have a pathway to deliver the output from a generator location to specific buyers via securing (or having the off-taker secure) transmission service rights that take the form of contractual rights to use physical slices of transmission capacity from point A to point B.[18] Thus, successful project development requires securing delivery via contractual transmission service rights to buyers.
  - Securing delivery on today's constrained transmission system is costly, and often requires the developer or the buyer to secure and purchase transmission rights across multiple systems.
  - Moreover, in some instances, project developers must demonstrate they have long-term transmission service just to have the opportunity to compete for a contract with a buyer.
  - Finally, not only is transmission service required, but it also must often be procured from transmission providers that may have a financial interest in prioritizing generation projects owned by their own merchant function when performing studies and determining transmission system capability available for sales to third parties, notwithstanding open access requirements intended to mitigate this self-interest.

- ***Buyers/contracting****:* Projects in the non-RTO West generally require long-term contracts in order to be successfully developed. The universe of candidate buyers, however, is typically much smaller than in RTOs, both due to transmission constraints/impacts (discussed above) and due to the limited types of contract structures that are viable outside an RTO.
  - The need for a project developer (or the off-taker) to have transmission service from the project location to the buyer's load generally limits the

[18] But "delivery" from point A to B is actually a convenient contractual fiction. In reality, the West is made up of a primarily AC transmission system and power actually flows across the path of least resistance on the system (and does not mirror the "point A to B" delivery structure of the transmission rights).

scope of potential buyers for a project to incumbent utilities or, in a limited number of states, large end-use customers (where direct access has been authorized). Thus, the primary avenue for successfully securing a buyer is typically:

- An incumbent vertically-integrated utility (investor-owned or consumer-owned) RFP.
- Depending on the state, IPPs may be allowed to sell to some large end-use consumers, but in the West the number of eligible large consumers allowed to choose their power supplier is relatively small. Some states have also approved limited customer-driven supply tariffs, offered through incumbent utilities, that facilitate stronger contracting with IPPs.

- Other contracting parties, like corporate buyers through a financial PPA, are generally not viable, as they require a durable, highly liquid wholesale electricity market (e.g., an RTO).

Project Development Basics in RTOs:

- ***Determining Ideal Locations***[19]***:*** Project developers use information from the RTO, including the following, to help identify suitable – and preferred/efficient – project locations:
  - Planned/future transmission facilities;
  - Nodal[20] electricity market prices; and
  - Grid congestion.

- ***Interconnection****:* Project developers must secure the ability to interconnect to the grid through the RTO's generator interconnection queue.
  - Thus, an independent entity, which is theoretically agnostic about which developers get interconnection service, performs the studies and oversees the interconnection process. Ideally, this independent oversight results in equitable access to interconnection opportunities for all developers.

- ***Transmission****:* Projects are generally not required to procure transmission service from the RTO or a transmission service provider to successfully develop a project. And projects generally do not need to pay for transmission service from one or more transmission providers to reach the buyer of the project's output.
  - While not the same as transmission service, RTOs generally offer a form of financial transmission rights (FTRs) as a type of financial replacement for transmission service. FTRs are designed to make parties that hold them

[19] Note that project developers also look at land-use, permitting, and environmental factors as part of determining project locations. But this paper is not focused on that aspect of project development, as it is not part of the commercial origination process and not generally affected by the electricity system functions at play in a given region.

[20] Nodes are specific locations where electricity is injected or withdrawn from the transmission grid.

economically indifferent as to which specific generator on the system is dispatched. But generation developers do not need to hold these financial entitlements if they do not wish to and can, instead, take on the risk of the price they will be paid at their location on the grid.
    - Thus, transmission service, as a discrete product purchased by a discrete generator (or project buyer), is generally not critical to project development in RTOs. Developers instead rely on market prices to give them insight on grid congestion and other important system conditions.[21]

- ***Buyers/contracting**:* Projects almost always require long-term contracts or tolling agreements to be successfully developed. In an RTO, project developers can reach a wide pool of potential buyers for the project's output. This is, in part, because in an RTO, having a separate physical delivery transmission service contract between the project and a specific load is generally not required.[22] Long-term contracting opportunities for a new project in an RTO may come from:
    - Utility RFPs from utilities *across the RTO footprint* (often without a requirement to deliver to the specific utility footprint);
    - Third-party load supplier RFPs/large end-use customers within the RTO footprint; and
    - Corporate buyer RFPs/other solicitations for resources to help meet corporate clean energy or other energy-related goals.

The next section of this paper compares the key functions that exist in the West today to the more coordinated functions typically seen in areas with RTOs. It also explores how day-ahead markets will (and will not) improve on the current functions in the West. For each key function, the paper discusses how more coordination might impact project development and provide benefits to resource developers and electricity buyers in the West. Summary tables of this comparison were included earlier in this paper as a quick reference guide to the narrative that follows.[23] The paper concludes with recommendations for Western policymakers interested in improving incremental functions to provide the benefits of lower-cost electricity resource development to their customers inside or outside an RTO framework.

[21] And some point-to-point transmission service does persist in smaller amounts in RTOs.
[22] If projects in an RTO want to be able to count toward the RA requirements of the region, they generally must have some form of "deliverability" which may include specific transmission service. It is still typically not the case, however, that the individual resource must be deliverable to the specific load of the off-taker.
[23] *See* Tables 1.1 through 1.5, following the Executive Summary.

III. Comparison of Key Functions in the West Today and the Anticipated Effects of Improving Coordination

Figure 1 and Tables 1.1-1.5 (included earlier in this paper) provide high-level overviews of some of the key functions/processes critical to project development which may be able to be improved/enhanced and better coordinated in the West. The present section first outlines how those functions have historically worked in the West and how the implementation of day-ahead markets may change (or not change) that historical function. It then reviews how the relevant function can be managed in a more coordinated way, as exists in regions with RTOs. Finally, it reviews how a more coordinated approach might impact project developers and their off-takers if it were implemented in the West.

While we note that the functions of RTOs may create a range of benefits, including improving project development, an RTO – or a suite of RTO-like functions – is not a cure-all and cannot solve all of the challenges facing the West. Moreover, it is critical to understand that in order to enable the greatest connectivity and planning benefits that will support more efficient resource development, these functions must span as large a geographic region as possible.

Consolidated Transmission System Operation & Control

Transmission system operation and control refers to the processes used to schedule and optimize the flow of electricity over the high-voltage transmission network to manage congestion and maintain reliability. The ability to access and economically deliver power across the transmission system is foundational to successful project development in every region, including the non-RTO West. Transmission-related rules, availability, and costs can often determine the set of potential buyers enabled by a particular grid connection, which in turn determines whether a project can proceed and whether it is economically attractive to potential buyers. Said differently, regardless of the region, once a developer identifies a high-quality project location (e.g., especially sunny or especially windy), the ability to physically and/or contractually move power across the transmission grid, and the costs of doing so, are often determinative of whether a project can be successfully developed (i.e., transmission makes or breaks many projects). Therefore, both who controls the transmission system and how they operate and charge for its use are hugely consequential to successful project development.

Historical Western Approach to Transmission System Operation & Control

In the West today, dozens of transmission service providers operate and control their respective portions of the electric grid under individualized tariffs. Each provider controls the power flows across its own system and applies its own rules for how available transmission service is studied, calculated, and sold. As a result, securing access to transmission service from one or more transmission service providers is among the most fundamental elements of successful project development in the West. Without it, even the

most cost-effective or technically promising projects are unlikely to be built. Yet, as discussed below, the way transmission service is structured in the non-RTO West is uniquely burdensome, adding significant costs and complexity to the origination of new resources.

Although power flows across the grid according to physical laws, customers in the West must often procure transmission along specific "contract paths" between a designated point of receipt (typically the generator) and a point of delivery (the buyer's load). Transmission service providers commonly (but not exclusively) use a rated path or contract path methodology to determine the availability of transfer service – and thus of contractual transmission service. Because the current contract path approach is inherently conservative, the amount of transmission capacity available for purchase is almost always less than what the grid can physically accommodate in real-time. In this way, commercial transmission availability is artificially constrained, which limits the number of projects that can demonstrate deliverability to buyers.

Additionally, parties to long-term power sales in the West must secure transmission service along their entire contract path from the resource to the buyer.[24] Because the Western grid is highly fragmented, customers delivering power over long distances (and sometimes even short distances) may need to work with multiple transmission providers.[25] Each transmission provider not only conducts its own study to determine availability and imposes its own requirements for requesting and securing transmission, but it also charges its own transmission rates. These transmission charges "stack" on top of one another, creating what are commonly referred to as "pancaked" transmission rates. Much like paying multiple tolls on a highway journey, these additive charges raise the costs of delivering power from project location to the buyer – frequently to the point where otherwise economic projects become uneconomic (and that is *if* transmission service is actually available).

Transmission delivery requirements also create real barriers to participation in competitive procurements. Many RFPs in the West require bidders to demonstrate that they have secured firm or conditional firm transmission service simply to qualify as an eligible bidder, and transmission delivery is often necessary to be eligible for selection as one of the finalists to receive a contract. Oftentimes, this transmission rights requirement disadvantages IPPs, as utility-owned generation usually has more readily available access to transmission service than a new project that must secure a scarce service simply to be competitive in an interested buyer's solicitation. In instances where transmission service over another system is necessary (as is often the case in the Northwest), utilities generally have only allowed their existing transmission rights to be used to deliver the output of utility-owned generation and have not permitted their rights to be utilized to deliver the

[24] This transmission service may be procured by the developer or by the purchaser or a combination of the two, but the burden of securing – or demonstrating availability of – transmission service often falls to the developer.

[25] For example, a developer seeking to sell power from southeast Idaho to Portland might need to obtain rights from PacifiCorp, Idaho Power, BPA, and Portland General Electric.

output of resources developed by IPPs.[26] Utilities also have an inherent information advantage in knowing when and what forms of transmission rights they will require as conditions in an RFP.

Taken together, these dynamics make transmission service in the non-RTO West administratively complex, inefficient, and scarce, as well as highly determinative of project viability. Instead of siting and selecting resources based on their economics or overall system value, developers and buyers must work within the constraints of contract path transmission availability and the paradigm of pancaked transmission costs. The result is a market where access to – and the cost of – contractual transmission service is often more determinative of project viability than underlying resource economics or physical grid capability. This limits optionality for buyers, discourages the development of remote but high-quality renewable resources, and generally raises costs for ratepayers. For generators, these transmission-related constraints significantly limit the pool of potential buyers for new projects.

None of these transmission service-related challenges have been alleviated with the advent of the real-time markets in the West, as the underlying contractual transmission service requirements for successfully developing a project remain fundamentally unchanged. These inefficiencies inherent in the contract-path model highlight why transmission system operation, as it is currently structured in the West, represents one of the most significant barriers to project development and why reforms that streamline or eliminate the need for contract-path transmission rights could unlock more competitive and cost-effective project development going forward.

Approach to Transmission System Operation & Control with a Day-Ahead Market

The implementation of day-ahead markets is unlikely to significantly reduce the transmission system operation and control-related barriers to project development that presently exist in the West. While Markets+ and EDAM seek to alleviate pancaked transmission rate barriers for energy dispatched *within* the day-ahead timeframe,[27] both markets deliberately sought to preserve the existing Western transmission paradigm for longer-term transactions. Specifically, resources typically must still secure underlying contractual transmission rights to fully realize the value of the resource. This is because both day-ahead markets and WRAP[28] still require, and are built around the concept of,

[26] This has been a particular challenge in the Northwest, where transmission across other systems (often BPA) is required to deliver to the utility buyer. But it is also true that in other locations in the West, utilities utilize transmission service on their own systems (often network service) to deliver the output from IPPs.
[27] Both markets do so by providing the market operator with the ability to use transmission capability within the market footprint for economic optimization *without* the use of hurdle rates/incremental costs for use of that transmission. But the ability to use transmission without those costs is limited to dispatch by the market operator in the day-ahead and real-time timeframes.
[28] The new RA program being developed for EDAM participants so far has included consideration, but not a formal proposal yet, of transmission-related restrictions akin to those utilized by WRAP.

requiring underlying contractual transmission rights to meet the market/program requirements.[29]

Importantly, under these new market frameworks, transmission providers will retain their existing transmission tariffs and functional control over their respective systems. The markets do not establish a consolidated transmission control function. As a result, many of the same concerns around pancaking transmission rates that exist in the West today (before day-ahead markets) will persist – even if they are somewhat diminished. While day-ahead markets may ignore pancaked transmission rates when dispatching energy, project developers and long-term buyers looking to sign long-term agreements cannot ignore these costs when structuring contracts given the current market designs and other programs, rules, and regulations. Consequently, for purposes of project development, day-ahead markets do little (if anything) to reduce the burdens associated with contract paths and pancaked transmission rates. Nor do they fully transition from contractual transmission rights to financial transmission rights, though each market takes small steps in that direction. Further, we do not expect that the advent of day-ahead markets will change the underlying requirements seen in many RFPs for resources to have firm or conditional firm transmission service to the buyer. While there is presently no clear path for the day-ahead markets to evolve in this regard, there is a possibility for this reform to take root in both markets.

In short, while day-ahead markets may provide some relief to the West's transmission system operations-related burdens, they stop short of eliminating the requirement for long-term transmission service, which remains a central barrier to project development and long-term contracting in the West.

More Coordinated Approach to Transmission System Operation & Control

A more coordinated transmission system would involve consolidating transmission tariffs, operating transmission on the basis of physical flows rather than contractual constraints,

[29] For example, WRAP requires participants to have firm or conditional firm transmission service for at least 75 percent of their forward-showing resources, further cementing the role of transmission contracts to deliver resources to loads in the West (and a similar requirement may be considered for the other regional RA program under development). Additionally, Markets+ participants must be participants in WRAP, reinforcing the need for firm transmission service from generation to load. While EDAM doesn't require participation in WRAP or another RA program, it does require participants satisfy a Resource Sufficiency Evaluation (RSE), which is essentially a test of whether each participant has enough resources to meet its own needs. The RSE in EDAM requires demonstration of transmission service across EDAM Entity areas for the underlying remote resource to be "counted" for delivery to a remote load/BA under the test. Thus, for a long-term contractual agreement between an underlying resource and a remote load, the ability to demonstrate delivery (using contract path transmission rights) remains a critical underlying requirement to fully unlocking the value of that resource, including its RA and RSE value. And the new RA program under development has considered but not proposed yet a transmission requirement akin to WRAP's in its initial draft proposals.

and eliminating requirements for transmission service to demonstrate delivery from specific resources to loads.[30]

While the concept of "transmission service" still exists within an RTO, it functions very differently than in the West. In an RTO, the transmission system is treated as a socialized network asset rather than a collection of contractually reserved paths. Functional control of the transmission facilities is transferred from individual transmission providers to a centralized market operator, which dispatches generation efficiently across the network as a whole. The cost of operating, maintaining, and expanding the transmission system is based on a fee charged to customers based on the size of their load or generator, not based on a customer's transmission contracts. Under this framework, the grid operator manages transmission (including investment in new transmission) based on the physical capabilities of the system rather than transmission service contracts or contract paths. In an RTO/ISO, the market operator dispatches generation according to economic merit order, based on both the offers submitted to the market and the physical limits of generators and the transmission system, rather than contractual constraints which may be highly disconnected from actual physics. Any congestion on the system is relieved in real time by redispatching all of the participating generation to achieve the most economic outcome; the cost of this congestion is reflected in locational prices. As a result, developers do not need to secure transmission service themselves to bring a project online.

Generators in an RTO/ISO can manage their financial congestion risk through tradable FTRs or Congestion Revenue Rights (CRRs). These instruments allow loads to hedge congestion exposure between specific locations without having physical transmission rights. By converting transmission rights from physical to financial ones, the market makes individual loads indifferent to which specific generator is dispatched, ensuring that lower-cost resources can serve load whenever physically feasible.

This distinction highlights a key difference between today's Western approach and a more coordinated system. Under the current model in the non-RTO West, the contract path model for transmission service rights is only loosely related to physical system limits, leading to inefficient use of the transmission system. In contrast, FTRs and CRRs respect these physical constraints without concern for any specific customers' contractual rights. FTRs and CRRs protect customers from congestion costs, while remaining purely financial overlays and not contractual delivery obligations. By respecting physical constraints

[30] The federal PMAs deserve special mention. BPA in particular is a dominant transmission provider in the Northwest, owning and operating 75 percent of the region's high-voltage transmission and to some degree dictating the terms of regional engagement for a wide range of its neighbors and the utility peers embedded within its footprint. This paper considers transmission providers largely agnostically, but BPA's mostly self-regulated status has an outsize influence on regional coordination. Readers should bear in mind the unique freedom that non-FERC jurisdictional incumbents like BPA and WAPA have to lead, embrace, or dismiss any given regional initiative. This fundamental legal and cultural reality hangs over much (not all) of the potential reforms discussed in this paper.

without artificially restricting dispatch, FTRs and CRRs avoid unnecessary limitations on system operations or contracting.

Impacts of a More Coordinated Approach to Transmission System Operation & Control

Today in the West, the limited availability and cost of transmission service are often key barriers to the development of efficient generation and storage projects. Project developers in the Western Interconnection would be able to reach more buyers without having to secure scarce and inefficient transmission rights with stacked charges if the West:

- Adopted consolidated transmission tariffs,[31]
- Implemented a flow-based transmission paradigm,
- De-pancaked transmission charges,
- Replaced physical transmission rights with FTRs/CRRs, and
- Eliminated rules and regulations requiring resources to deliver to specific loads via firm and conditional firm transmission.[32]

Consolidating transmission operations and control in the West, together with the elimination of conservative rules governing transmission availability, would expand the range of viable project locations by removing artificial contractual and cost limitations and allowing the physics and economics of the transmission grid to guide development toward the most suitable locations. Improved transmission functionality would enable developers to make project development decisions based on expected revenues at specific points on the grid rather than on artificial transmission constraints, while corporate and utility buyers would gain access to a larger and more competitive pool of resources. These changes would reduce delivered power costs, increase competition, unlock new areas for generation and storage development, and lower costs for end-use customers.

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[31] Additionally, the consolidation of transmission services and control may very well result in – or at least incentivize – consolidation of BAs in the West. Consolidation of BAs could also offer a number of benefits to customers in the West including better reliability management and reduced reserve requirements. However, for project development, the benefits of BA consolidation are likely much smaller than those gained from reforms related to transmission system operation and control. Generation-only BAs have been developed in the West recently, in part as a work-around for generators exposed to ancillary service charges of incumbent BAs. Generation-only BAs have mitigated, at the cost of operating a separate BA on a 24-hour basis, the impact of BA balkanization on independent generators. We also note that RTOs themselves are not necessarily synonymous with BA consolidation: MISO, for example, retained significant local BA responsibilities well after it had consolidated transmission service and operations.

[32] This change would impact project developers who have historically been able to successfully develop generation projects by developing strong portfolios of transmission rights – just as it would affect incumbent transmission owners with extensive rights on their own systems. However, it would also benefit the overall region by eliminating the competitive advantages of gathering large transmission portfolios. Migrating from the present system to a flow-based, financial rights-based system would require a significant negotiation between incumbent rights holders and other stakeholders, just as it has in every RTO. RTOs have come up with a variety of ways to structure the new blended rates, while respecting some legacy contracts and rights.

To fully realize these benefits, two key reforms are necessary. First, transmission providers would need to turn over functional control of their transmission facilities to a centralized service provider. Second, underlying programs like the WRAP and the utility resource procurement processes would need to reduce or eliminate requirements to secure firm and conditional transmission service.

None of these changes would be simple. Their implementation would require significant coordination and a willingness by incumbent transmission owners to cede a degree of operational control, which has historically been challenging in the West. However, successful implementation of these changes could offer substantial economic benefits.

Standardized Generator Interconnection Procedures

New generation and storage projects seeking to plug into the grid (i.e., interconnect) must secure interconnection service – obtained at the end of an extended engineering study and construction process – from the relevant transmission owner.[33] Thus, generator interconnection is a critical component of successful project development. Transmission owners in the West, and RTOs in other regions, use generator interconnection queues and associated study processes to evaluate interconnection service requests, assess the existing grid's ability to accommodate the new interconnection, and identify any transmission system upgrades needed to support the transfer of new power supplies. Locations with lower upgrade costs and areas with streamlined interconnection processes are generally more promising for developers.

In recent years, interconnection queues have become heavily clogged with requests for interconnection service, making it increasingly difficult for transmission owners or RTO/ISOs to conduct timely and meaningful studies to move projects through the process. These challenges have plagued virtually every region of the country, including both RTO and non-RTO systems. While interconnection reforms are ongoing, and have resulted thus far in some queue backlog reductions, generator interconnection challenges remain a core challenge for generation development in all regions.

Historical Western Approach to Generator Interconnection

To interconnect new resources in the West, developers must navigate the different rules and procedures contained in each transmission provider's Open Access Transmission Tariff (OATT), or equivalent federal or state tariff. Each transmission provider runs its own generator interconnection process, in addition to – and separate from – its transmission service request process. While there is some similarity in these individual interconnection processes, as many transmission providers in the West recently transitioned to cluster-

[33] Interconnection service is distinct from transmission service, which was discussed earlier in this paper. Interconnection service is the ability to *connect* to the grid, while transmission service provides the ability to flow/move power across the grid.

based interconnection studies[34] consistent with FERC Order 2023, nuances in the processes used by each transmission provider remain. Each individual entity has its own set of rules, timelines, deposits, business practices, and requirements for demonstrating project readiness (such as "site control").

As a result, interconnection in the non-RTO West is uniquely complex and inconsistent, with each transmission provider administering one or more separate interconnection process, each with its own unique rules governing queue entry, commercial readiness, study procedures, and timelines.[35] Thus, in addition to facing backlogged generator interconnection queues prevalent across the country, project developers in the non-RTO West must also understand the specific interconnection rules of dozens of transmission providers. This dynamic can frustrate project development, and the shifting, and sometimes unpredictable, rule changes can significantly increase development costs.

In the non-RTO West, when interconnection studies identify the need for system upgrades (often called network upgrades), the upfront costs of those upgrades are generally assigned to the generator (or cluster of generators) that triggers the need, to be refunded over time as a customer billing credit from the transmission owner. These upfront costs are typically assigned under a strict application of the cost causation principle – the project(s) that triggers the need for an upgrade pays the full cost initially, even if other system users will clearly benefit from those upgrades. This creates strong disincentives for developers to site projects in areas that might require major upgrades, even if those locations are otherwise optimal and upgrade costs are refunded over time.[36] When major upgrades are needed and the next generator or set of generators to interconnect must shoulder the initial upfront cost of those upgrades, projects can stall as developers wait for someone else to finance those costs. It also means that subsequent generators can benefit from prior expansions without having to pay in advance for the full costs. Taken together, this dynamic frustrates grid expansion and generator interconnection in the West.

Furthermore, it is important to note that, in all regions, the party performing the generator interconnection studies has important decisions to make around study assumptions and processes, which are at times based on grid conditions that are not publicly available or are difficult to ascertain. In the non-RTO West, the party performing these studies is often not a neutral body but rather the incumbent transmission owner, which is also often a utility that owns generation. This structure creates potential for self-interested behavior whereby the incumbent utility advantages its own generation resources in the study

[34] Cluster studies are studies where a "cluster" (or group) of projects are studied in a combined manner to assess the impacts – and needed upgrades – for their interconnection to the grid. These have become preferable to the "serial" study process because a serial study process leads to many necessary "restudies" if earlier queued projects drop out of the queue.

[35] For example, PacifiCorp has three separate interconnection queues: existing projects, certain state jurisdictional interconnections under a serial queue and some state and all federal jurisdictional interconnections under the cluster study.

[36] Even if these network upgrades costs are reimbursed to the generators over time, as is often the case in the non-RTO West, these costs deter buyers and make projects less economic.

process (this perverse incentive does not hold true in the same way for consumer-owned entities such as federal PMAs). This advantage may rely on the interconnection study process but may also be exercised in generation procurement RFPs, making them less competitive. In some utility RFPs, for example, transmission-owning utilities have allowed projects supported by provisional interconnection studies that were only made available to the utility itself eligible to proceed, without communicating this information to other bidders waiting in the interconnection queue. In other cases, interconnection deadlines that were unknown to parties outside of the transmission-owning utility have been used as cutoff dates for RFP bid submissions.

In situations like these, having an independent entity perform these interconnection studies would clearly support better wholesale competition and alleviate the potential for conflicts of interest or undue favoritism towards generation projects proposed by the incumbent transmission provider.[37]

Approach to Generator Interconnection in the West with a Day-Ahead Market

None of the fundamental rules or processes around generator interconnection are expected to change with the advent of day-ahead markets in the West. And thus, the current patchwork processes for generator interconnection are expected to persist.

More Coordinated Approach to Generator Interconnection

In regions where generator interconnection is performed by a single, regional entity (generally an RTO), interconnection queue backlogs are also a challenge. But there is typically a single, consistent process administered by the independent entity for higher-voltage interconnections across the footprint. Thus, in regions with more coordinated approaches to interconnection, developers generally face the same requirements no matter where they interconnect. The transparency of a unified queue also allows policymakers and buyers to better understand the pipeline of projects and the status of interconnection requests.

Having a disinterested party (at least in theory) establish study assumptions and methodology and perform interconnection studies offers inherent benefits because it increases confidence from all project developers that the outcomes of the interconnection process are fair, reasonable, and not discriminatory. It also increases confidence that all projects, whether incumbent-owned or independent – when similarly situated – have the same chance to successfully complete the interconnection process.

Additionally, regions with more coordinated interconnection processes often employ more sophisticated cost allocation methods for distributing required upgrade costs. These methods can do a better job of assigning an appropriate share of costs directly to the interconnection customer, while socializing the remaining costs more quickly across all

[37] These favoritism problems are much more common with investor-owned utilities that own transmission than with federal PMAs (BPA and WAPA) that lack the same financial incentives related to generation ownership.

system users in proportion to the benefits they receive from the upgrades. This approach can help to reduce the phenomenon where projects avoid interconnecting in an area where they know a costly upfront upgrade might be triggered.

Still, significant challenges remain even in regions with a coordinated interconnection process. Regions with RTOs have seen significant backlogs in processing their interconnection queues in recent years and have considered and implemented new approaches to help address these challenges. While these challenges may be bigger in scale than those facing even large Western transmission providers like BPA, RTOs have also been more nimble in piloting novel solutions to interconnection queue management, including software automation.

Impacts of a More Coordinated Approach to Generator Interconnection in the West

While no system is perfect, the difference between navigating dozens of bespoke processes (in the West) versus working within one standardized framework is stark. A consistent, independent interconnection process in the West would reduce uncertainty for developers, could distribute upgrade costs more fairly, and could provide regulators and buyers with greater visibility into the project pipeline. This could potentially speed up development timelines, make more projects financeable, and ultimately expand the range of resource options available to buyers.

Ultimately, the creation of a single interconnection queue across a large area, run by an independent entity, could offer significant benefits to project development in the West. While a more coordinated interconnection process is clearly not a cure-all for the woes facing generator interconnection, a consistent, region-wide interconnection process may still be preferable to dozens of different ones.

Durable and Complete Electricity Markets

In an RTO/ISO, generation and storage developers rely on clear, transparent price signals to decide where to site projects. These price signals are provided via highly granular, nodal Locational Marginal Prices (LMPs) for energy and ancillary services from real-time and day-ahead organized wholesale markets.[38] The "best" commercial locations for electricity generation and storage assets are the locations on the grid where the market prices are highest relative to the cost of producing power from that asset. Adding generation in areas with significant load and/or limited transmission constraints for delivering to load can help reduce the cost of serving the system. Conversely, adding generation to an already highly constrained area – such as an area with a lot of wind but insufficient transmission – can increase system costs and provide limited benefits absent a parallel plan to expand transmission capacity. Thus, having visibility into nodal day-ahead and real-time electricity

[38] Ancillary services are the services needed to maintain a reliable and stable power grid. There are various types of ancillary services, with key categories including: frequency regulation, spinning/non-spinning reserves, voltage support/reactive power, and black start capability.

market prices that reflect the full value and cost of electricity services at a particular location is crucial for successful project development. These price signals also help electricity buyers assess the relative value of different projects with which they may wish to contract.

In some instances, project developers may also rely on the existence of a liquid, dependable electricity market to finance and construct their projects. Market liquidity and durability ensure that developers have multiple contracting options, enabling innovation in deal structures such as virtual PPAs. Without transparency into complete grid costs and a durable market structure, competition can be limited, and the true system costs or benefits of incremental resources can be obscured. Transparent prices offered by day-ahead and real-time price signals, combined with highly liquid and durable markets in which to transact, therefore, play a critical role in successful project development.

Historical Western Approach to Electricity Markets

Before the advent of real-time markets in the non-RTO West, visibility into electricity market prices was highly limited, with prices only reported at a small number of trading hubs (e.g., Mid-Columbia and Palo Verde). Sometimes prices were not even published on an hourly basis, instead reported only for peak and off-peak periods.

Today, the West has improved short-term price transparency from the operation of real-time markets like WEIM and WEIS. These markets provide insights into real-time nodal electricity prices across a wide swath of the West. The real-time markets have also increased the ability to optimize imports and exports between different BAs that are within the same real-time market footprint, increasing efficiency of real-time energy trades across the West. But this only happens "on the margin" for resources that can easily ramp up and down in real-time to help balance supply and demand using the limited transmission capacity made available to the market optimization. These real-time transactions have been estimated to represent around five percent of total transactions.[39] As a result, real-time markets in the West primarily overlay, rather than replace, the existing bilateral market structure that supports day-ahead and longer-term trades among grid participants.

Approach to Electricity Markets in the West with a Day-Ahead Market

The West is poised to improve upon the existing structure by implementing day-ahead markets. The two day-ahead markets proposed in the West (EDAM and Markets+) will encompass and optimize far more electricity transactions than today's real-time markets and offer significantly greater benefits by enabling a broader, coordinated footprint to be "set up" the day before operations.

[39] For instance, a report from SPP regarding WEIS operations indicated that the amount of imbalance energy settled in WEIS in Winter 2024 averaged five to seven percent of total energy within the market (*see* SPP Market Monitoring Unit, *WEIS Quarterly State of the Market, Winter 2024* at 27 (May 8, 2025), available at: https://www.spp.org/documents/73812/weis%20spp%20mmu%20qsom%20winter%202025.pdf).

Both day-ahead platforms will use the transmission capacity available to the market to optimize day-ahead commitments and produce financially binding schedules for generation and load within their respective footprints. By allowing the market to optimize imports and exports between BAs within the same market footprint, these day-ahead markets will improve generation dispatch efficiencies, reduce system costs, and lower renewable generation curtailment. These benefits generally stem from allowing the market to optimize imports and exports between BAs within the same market footprint.

Nonetheless, there are still design issues that have the potential to limit benefits of the day-ahead markets. For instance, the current design and congestion revenue allocation approach for EDAM is widely recognized to incentivize self-scheduling (being a price taker, rather than economically bidding). This design is an outgrowth of retaining the traditional contract-path paradigm for transmission alongside EDAM, and thus (appropriately) allowing third-party rights holders to hedge the value they have invested in transmission rights. While there are efforts underway to address these incentives and promote more economic participation in the market, the resolution will be complicated and potentially contentious, absent a deeper transmission reform as described in this paper. And, under the present design, if significant self-scheduling or other out-of-market transactions occur consistently, the benefits of these markets could be limited relative to a more traditional market structure.

Additionally, neither day-ahead market fully incorporates all reliability and grid support functions – commonly referred to as ancillary services – into the market optimization. As a result, BAs will continue to procure and provide various ancillary services outside of the market optimization. This means the market prices in EDAM and Markets+ will not *fully* reflect the true costs of running the grid. In addition, both markets are expected to allow some transactions to continue as they do today – meaning they will effectively be outside of the centralized optimization.[40] Because the full transmission and generation network will not be economically optimized through the market – and may rely, in part, on donated transmission – day-ahead prices may not reflect a fully optimized system dispatch, potentially distorting market pricing signals.

Moreover, rules governing market participation, transmission provision, and other activities may vary across BAs within the same day-ahead market (under the proposed market structures for both EDAM and Markets+, each participating BA retains a distinct subset of participation rules within its own transmission tariff). And transactions between the markets (across their "seams") are likely to introduce price distortions and reduce the

[40] In Markets+ this may be accomplished with "transmission opt-outs" and within EDAM through "balanced self-schedules", which are both mechanisms that will, in different ways, seek to enable transactions that are not optimized by the market to continue. One policy reason for this retention of many existing bilateral transaction modes is because the markets are a limited reform: they dilute but don't eliminate the expectations and requirements for power suppliers, marketers, utilities, and some end-users to obtain contract path transmission rights. Thus, parties holding those rights continue to demand a way to exercise what they've paid for. The only way to honor those rights is through some form of opt-outs.

accuracy of price signals. Taken together, these factors will limit the full extent of price transparency in the West, even within the day-ahead markets.

Finally, the liquidity and durability of these new day-ahead markets remain somewhat unproven. While day-ahead markets are expected to significantly increase the volume of transactions cleared through market optimization – thereby supporting greater liquidity – they are also voluntary. In theory, a utility could leave the market with little notice[41] and minimal financial consequence to itself. Thus, confidence in the long-term liquidity and durability of day-ahead markets may be insufficient to support long-term contract structuring. As a result, the methods commonly used by non-utility buyers in areas with established RTOs – such as virtual PPAs and demand response participation – may not be feasible under the day-ahead market structures currently envisioned for the West.

More Coordinated Approach to Electricity Markets

A more coordinated and comprehensive approach to electricity markets exists in regions where all energy and ancillary services are fully co-optimized and cleared through the market, and where utility participation is durable and lasting. In regions where virtually all grid services are cleared through and priced by the day-ahead and real-time market, there is broader confidence that market prices accurately reflect the relative overall value of different locations on the grid. Where nodal prices are public across the entire system, the universal price formation produces deep liquidity, enabling all generators to transact under the same rules and allowing buyers to evaluate options against transparent benchmarks. Deep liquidity and confidence in a durable market existence also mean developers can confidently model price outcomes at different nodes and use those expected market prices as a foundation for long-term power sales.

Additionally, because RTO participants cannot as easily leave an RTO, developers and their customers have more confidence in the market's long-term stability.[42] This confidence has enabled the development of sophisticated contracting structures that allow generation to be contracted to non-utility buyers, including corporate customers such as Amazon and Target. These entities often seek to contract with IPPs to meet corporate sustainability and accelerated energization goals, and can do so through financeable contracts that rely on generators selling their output into the RTO's deep and durable energy market, rather than directly serving the off-taker's discrete load.

Impacts of a More Coordinated Approach to Electricity Markets in the West

Greater price transparency and liquidity – and the inclusion of ancillary services within a market construct – would provide clearer investment signals for developers in the West and greater confidence that market prices fully reflect the relative value of resources across locations. This, in turn, would support development in the most beneficial areas of

[41] Roughly six months is required for a participant to exit EDAM.

[42] While RTO participation, except where states have ordered it, is fundamentally voluntary, FERC still considers several factors in reviewing proposed withdrawals from RTOs, including the extent to which remaining RTO participants might be harmed or stuck with undue stranded costs.

the grid and allow utilities and regulators to benchmark procurement decisions against transparent, publicly available market data, helping reduce electricity costs for buyers. While the non-RTO West has made meaningful progress in improving price transparency through real-time markets and is poised to improve further with day-ahead markets, liquidity is expected to remain somewhat limited, and prices do not yet support the full range of grid services that are priced in more mature markets.

Moreover, the West can still improve market structures such that they are more durable and dependable, which can diversify the kinds of electricity off-take deals available in the region. A stable, durable market in the West could enable new off-take arrangements, such as virtual PPAs for corporate buyers, that are unlikely to emerge under current or near-term Western market designs.

Regional Resource Adequacy

RA refers to the ability to ensure that enough generation and demand-side resources are available to meet forecasted electricity demand, plus an additional margin, known as the Planning Reserve Margin (PRM). RA standards are designed to account for uncertainty, extreme weather, or unplanned outages. RA is, fundamentally, a planning and reliability concept focused on ensuring that there is enough available generation on the system to keep the lights on during periods of stress.

In practice, RA requirements can be met through a mix of generation, storage, and demand response resources. Because the grid operates across interconnected regions, the adequacy of one system often depends on the availability and deliverability of resources in neighboring systems. This makes RA coordination and transparency essential.

For project developers, RA programs matter because they define how resources count toward RA requirements (i.e., how much capacity credit they receive). RA programs can contribute to unbundling a fungible capacity product that can represent an additional value stream for project developers. RA rules are, therefore, critical components of determining which projects may be best situated for long-term procurement contracts. A transparent, well-functioning RA framework creates clear signals about where and when new capacity is required, improving investor confidence and supporting project financing. Conversely, fragmented or opaque RA programs can discourage investment by making it difficult for developers to demonstrate that their projects will qualify as a capacity resource (in a reasonably known quantity) for buyers. In short, RA is not only a cornerstone of system reliability but also a key determinant of whether and where new generation projects can secure contracts and move forward.

Historical Western Approach to Resource Adequacy

Today, in the West, RA obligations and expectations, to the extent they are established, are generally set by utility regulators and have historically involved a simple PRM or a percentage above anticipated peak load levels that utilities are expected to build and

measure in their Integrated Resource Plans (IRPs). These requirements have not generally included full RA obligations and requirements that are measured on a regular basis to ensure the planning reserve margins of the IRPs are achieved. Additionally, there are currently no mandatory regional or national RA requirements, or rules about how to count capacity towards peak needs. In many cases, when a project secures a PPA with a buyer in the non-RTO West, the seller conveys all the resource attributes, including the RA capacity value, to the buyer.

In 2019, stakeholders began developing the WRAP, the first coordinated regional RA program in the West outside of CAISO/California. WRAP is the first RA program of its kind and is designed to operate independent of an organized wholesale market like an RTO/ISO.[43] Its goal is simple: to make sure each participant contributes enough resources across the region to reliably meet demand. WRAP seeks to accomplish this goal by creating consistent metrics for achieving RA goals and, when it is binding, holding participants to these requirements, including through penalties for noncompliance. It also seeks to ensure that participants are not inadvertently relying on the same capacity to meet their reliability goals, something the bilateral and uncoordinated RA structures preceding WRAP did not protect against. Solving the "musical chairs" problem (who is left without a chair when the music ends, i.e., during an RA crisis) was a shared regional motivation to form WRAP.

WRAP is built on a voluntary participation model and has recently seen significant attrition in its expected footprint, with several entities indicating their intent to withdraw from the program. While participation in WRAP is voluntary, entities that elect to participate and commit to the binding phase are subject to mandatory requirements and defined penalties for failure to comply. Today, the program is operating as non-binding. However, in the Fall of 2025, participants faced a deadline to either commit to binding participation or provide notice to withdraw. Sixteen entities elected to continue forward with binding participation for the Winter 2027/28 season, while six entities – generally those planning to join EDAM – opted to withdraw. Additional entities have since withdrawn as well.[44] This outcome fractures the previously anticipated WRAP footprint, while also opening up the potential for an alternative RA program to be developed for EDAM Entities.

In the Spring of 2026, a group of utilities that are expected to join EDAM announced their intentions to create a regional RA program available on a voluntary basis for those that join EDAM. This new program would be overseen by the Board of the Regional Organization for Western Energy (ROWE), should the Board accept that responsibility, and is presently in

[43] WRAP was developed before the day-ahead markets and was designed to operate with or without them in place. Both day-ahead markets were designed with an understanding of WRAP and in a manner that seeks to allow WRAP to function as designed. Today, WRAP participants are expected to span participation in both future day-ahead markets. Thus, WRAP must be capable of coordinating/operating with both organized day-ahead markets, though recently WRAP has indicated an intent to align its operational program with Markets+ (while still enabling non-Markets+ participant participation).

[44] NV Energy, PacifiCorp, Portland General Electric Company, the Public Service Company of New Mexico, and Calpine Solutions are among those withdrawing.

the early stage of development and obtaining stakeholder input. Thus, at this juncture, the West remains in a state of uncertainty and flux regarding the future footprint and scope of regional RA programs.

Regardless of the ultimate footprint, WRAP continues to rely on the underlying firm/conditional firm transmission rights paradigm in the West, at least for the majority of resources.[45] As a result, participating resources in Western RA programs are expected to be required to demonstrate deliverability to a specific load rather than to the aggregate of loads. This source-to-sink deliverability requirement, which is enforced in WRAP through the same significant deficiency penalties as the capacity obligation itself, has proven infeasible for some parties to date. Also, because WRAP is not presently inherently integrated with a wholesale market, it may have to rely on less efficient mechanisms and/or coordinate across multiple day-ahead market rules and regulations to function effectively. However, there are new efforts currently underway to better integrate WRAP with the market dispatch of Markets+.[46] While WRAP and the EDAM-focused RA program are important steps forward, they could continue to reinforce some of the very transmission barriers that make project development more difficult in the West.

Approach to Resource Adequacy in the West with a Day-Ahead Market

Day-ahead only markets do not inherently include an RA component and are generally not expected to determine the West's approach to RA, although Markets+ includes a requirement to join WRAP (promulgated after WRAP's creation). The EDAM construct is a clearer example of how existing RA rules of the West have been otherwise left in place.[47] Markets+ made a market design decision that requires its participants to be part of a regional RA program. Thus, in the Markets+ context, load serving entity participants will all be part of WRAP and will need to comply with WRAP requirements, as well as with any RA obligations that may be set by or accepted by their individual regulators. In both day-ahead markets, utilities will still need to satisfy the rules, if any, of their state regulators.

Regional RA programs can offer the West significant benefits. When they cover a sufficient geographic scope, these programs help improve visibility into whether the region has enough resources to meet demand and create consistency in how resources are counted towards reliability needs. They also establish accountability for participants to plan ahead to meet their needs, while also providing a framework for beneficially sharing resources in

[45] The new EDAM-focused RA program has also contemplated a similar requirement. *See* ROWE, *EDAM Resource Adequacy Workshop #5: Transmission, Compliance Structure, Reporting and Transparency* at slide 5 (May 26, 2026), available at: https://rowesternenergy.org/wp-content/uploads/2026/05/Workshop-5_Final.pdf.

[46] Markets+ does condition participation by load-serving entities in the market on participation in WRAP and has a must-offer provision for WRAP-tied capacity, but the RA program design was completed on its own merits and is intended to be interoperable with both Markets+ and EDAM.

[47] EDAM also includes a day-ahead RSE which is intended to ensure each participating BA comes into the market capable of meeting its own needs and is not inappropriately relying on the capacity of other BAs without having an underlying contract for the required capacity. While there is a new effort to consider an EDAM-focused RA program, it was not a necessity for EDAM's launch.

the operating time frame when a shortage occurs. But when RA programs rely on rigid underlying firm/conditional firm transmission service requirements, they perpetuate existing barriers to project development in the West.

More Coordinated Approach to Resource Adequacy

A more coordinated approach to RA is offered in regions where RA rules and requirements are set by the market operator (and the RA area aligns with the energy market's footprint). In these regions (generally RTOs), the market operator/service provider sets the RA obligations for each participating utility based upon standardized requirements and study results, with varying levels of influence by state regulators.

Each utility then procures enough resources to meet that obligation through self-service, bilateral transactions, and/or capacity procured through a region-wide capacity auction. Under these more coordinated programs, the capacity values of generation and demand response resources can be separately traded and transacted for. RA frameworks provide an additional avenue for developers to get payments for their capacity (matched to the region's need for particular capacity resources) while also increasing the availability of capacity supply for buyers/utilities.

The exact nature and structure of how utilities meet their RA obligation varies across RTO regions. Some regions rely entirely on capacity markets, the mandatory versions of which have run into significant issues in recent years. Other regions (where state policies have retained more traditional regulatory roles) use residual, voluntary capacity markets that offer an additional way to buy and sell spare capacity. However, a capacity market construct (mandatory or voluntary) is not a prerequisite for implementing a more coordinated approach to RA. And even where a more regional, coordinated RA paradigm is in place, utilities must continue to comply with the relevant state policies and rules to the extent those policies are in place.

Impacts of a More Coordinated Approach to Resource Adequacy in the West

The West could benefit from a more coordinated, centralized approach to RA. While WRAP and the new EDAM-focused RA program are poised to provide greater coordination to many entities, they both may fail to fully capture some of the RA benefits realized in other regions, given the likely embedded contract-path transmission delivery requirements.

A more coordinated approach to RA in the West, up to and including a voluntary, residual capacity market, could offer significant benefits. For developers, a consolidated RA program (but which does not include a rigid contract-path delivery requirement) could provide new options for contracting and capacity payments for their resources, by identifying needs which are not currently filled despite available resources to serve those needs. Additionally, having a stronger market where RA capacity is tradeable between parties, and possibly between programs or regions – in line with that seen in regions covered by CAISO, SPP, and the Midcontinent ISO (MISO) – could increase competition for capacity resources. It could also offer buyers more access to different capacity resources and types, providing benefits to customers.

Independent, Regional Transmission Planning and Cost Allocation

Regional transmission planning involves conducting long-term studies to determine what additional transmission upgrades are required on a transmission system, approving their development, and allocating associated costs across a region – a process referred to as transmission cost allocation. Effective transmission planning is critical to opening up new areas for generation and storage assets to be sited and to accommodating new loads on the system. Adequate and proactive transmission planning is, therefore, foundational to the project development process.

Historical Western Approach to Transmission Planning and Cost Allocation

Transmission planning in the non-RTO West today is highly fragmented and mostly utility-driven. Each transmission operator is responsible for planning local upgrades on its own system. In addition to local planning, regional planning under FERC Order 1000 also occurs in the West. Presently, the West has three Order 1000 planning regions: CAISO, NorthernGrid, and WestConnect.[48] To date, the two non-CAISO Order 1000 planning regions have largely amounted to aggregating local plans as a minimal compliance exercise, rather than identifying and approving genuine regional projects. In fact, no major regional projects have advanced under these regional processes in the non-RTO West.[49]

Some of the largest transmission providers in the non-RTO West are not investor-owned utilities subject to FERC jurisdiction. Non-jurisdictional utilities in the West (like BPA and WAPA) do participate in regional transmission planning under Order 1000 but have largely declined to participate in regional cost allocation under those programs.[50] FERC has no authority to mandate that these non-jurisdictional utilities participate in the regional cost allocation under Order 1000, absent a change in law by Congress. Accordingly, a non-jurisdictional utility can be allocated a portion of the costs of a transmission project with large-scale regional benefits only if it voluntarily accepts them. The largely voluntary participation by non-jurisdictional transmission providers in cost allocation mechanisms is one reason that regional transmission planning processes – outside of CAISO – have not resulted in any incremental transmission approvals and have never applied their transmission cost allocation mechanisms. As a result, transmission expansions planned through existing regional planning processes in the West are often piecemeal.

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[48] SPP will become a fourth planning region as SPP's RTO Expansion initiative in the Western Interconnection begins engaging in transmission planning efforts for that region.

[49] Some projects are under development for long haul deliveries (e.g., TransWest Express and SunZia) but their development and approval have taken place *outside* of a formalized, regional transmission planning process (like the Order 1000 processes) and has not relied on the untested cost allocation approaches of those regions.

[50] For a deeper understanding of the unique aspects of BPA transmission planning and cost allocation for commercially driven transmission, readers may refer to a recent whitepaper prepared by NIPPC and Renewable Northwest on the topic that included twenty-two recommendations. Most of the recommendations are being addressed either by WestTEC or by BPA reforming its internal processes. See "'Appropriate and Required': BPA and Building the Grid the Northwest Needs" (May 2023), available at: https://nippc.org/wp-content/uploads/2023/05/BPA-Tx-Whitepaper-050323.pdf.

Furthermore, transmission expansions that provide widespread regional benefits may no longer be economic if the costs of the project are allocated only to FERC jurisdictional utilities and not to all transmission providers in proportion to their benefits. For these reasons, existing transmission planning and cost allocation processes are adequate to solve local reliability issues but have failed to address broader regional needs – such as delivering Wyoming wind to loads in the southwest or California. In short, today's transmission planning paradigm does not support transmission planning to new, beneficial resource areas.

Recognizing that regional transmission planning in the non-RTO West has not been successful under FERC orders prior to Order 1920, new forums have been created. For instance, the Western Transmission Expansion Coalition (WestTEC) provides a venue for developing voluntary, non-binding 10- and 20-year transmission plans. However, because WestTEC operates outside of any regulatory process and does not involve cost allocation, any transmission projects emerging from the voluntary effort would still require various multilateral agreements among participants and evaluation in relevant regulatory processes to move forward. A second separate effort, the Western Transmission Consortium, seeks to help fill funding gaps for identified transmission solutions by bringing forth creative financial solutions and partnerships, which may complement the identification of beneficial transmission projects through WestTEC.

Additionally, FERC Order 1920 reforms imposed on jurisdictional utilities are on the horizon for transmission planning regions. These reforms will implement longer-term transmission planning horizons (20 years rather than the historical 10-year standard) and will build in a greater role for states in cost allocation processes, among other reforms. In that spirit, Western state regulators have developed a new voluntary framework for cost allocation for some new transmission projects through the Western Interstate Energy Board's Committee on Regional Electric Power Cooperation and its Transmission Collaborative. Still, it is not clear whether these efforts will result in meaningful changes to the status quo of transmission planning in the West.[51]

While the efforts above may provide incremental benefits to the historical stalemate for regional transmission development in the West, they do not yet offer a reliable platform for assuring that projects will be built and that effective cost-sharing agreements will be developed. In practice, regionally planned projects continue to be advanced primarily to serve incumbent utility needs, with limited optimization across the larger grid due to the absence of an effective regional planning and cost allocation process.

Approach to Transmission Planning and Cost Allocation in the West with a Day-Ahead Market

Day-ahead markets will not change transmission planning paradigms in the West. The current structure of local planning and ineffective regional planning through Order 1000

[51] Given the lack of meaningful changes seen as a result of Order 1000, it is unclear whether Order 1920 will result in many tangible improvements to transmission planning in the non-RTO West such that transmission projects will actually be approved through these regional forums.

(and, in the future, Order 1920, which may make a bigger difference) will continue to apply. Thus, the existing transmission capacity limitations in the West will persist.

Day-ahead markets may provide more visibility into physical transmission congestion on the grid and into the potential for economic transmission expansion. But these additional data points alone are not expected to materially alter the transmission planning, approval, and cost allocation processes in the West. Meaningful change would require additional structural reforms to the transmission planning and cost allocation processes.

More Coordinated Approach to Transmission Planning and Cost Allocation

RTOs offer a more comprehensive approach to transmission planning and cost allocation. Under the more coordinated approach in regions with RTOs, independent entities play a central role in approving transmission needed to serve regional footprints. As independent entities, RTOs perform comprehensive planning across their footprint, and identify transmission projects based on regional reliability, economic, and policy benefits. Costs are allocated among beneficiaries according to known and well-understood methodologies, though the specific methodologies vary significantly based on project type and the RTO's rules. In addition, many RTOs require large regional projects to undergo competitive solicitations to identify the best transmission developer for bringing the project online in a timely and least-cost manner. This structure prevents utilities from building projects solely for their own advantage, reduces costs through competition, and facilitates the advancement of transmission needed to unlock high-value resources. From a project development perspective, the presence of a well-developed, well-understood, and independent transmission planning process gives developers confidence that access to transmission will be guided by system-wide needs and opportunities rather than by individual utility priorities.

This is not to suggest that transmission planning and cost allocation in RTO regions are without challenges. Initial transitions to regional cost allocation frameworks will always involve difficult negotiations among incumbent transmission providers and other stakeholders. This paper noted the nature of these negotiations above with regard to de-pancaking: every RTO has had to undergo this process. It is no coincidence that the same negotiations may encompass both de-pancaking of existing transmission systems [establishing new regional or zonal blended (i.e. postage stamp) transmission rates] as well as cost allocation for new transmission facilities. While some regions have successfully performed transmission planning and cost allocation for years, new challenges are emerging, especially as the need for transmission grows and as electricity rates face rising cost pressures from many directions.[52] Nonetheless, regions with RTOs

[52] For instance, a set of state utility commissions recently filed a complaint at FERC arguing the Midcontinent ISO inflated the benefits of a set of transmission projects that were approved in December 2024. *See* Complaint, *North Dakota Public Service Commission et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket No. EL25-109-000 (July 30, 2025) available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250730-5091&optimized=false&sid=6a9fb62d-1b6b-4a24-8940-3f3eab23e6c5.

have demonstrated a stronger track record of developing transmission projects that deliver overall net regional benefits than has been observed in the non-RTO West.

Impacts of a More Coordinated Approach to Transmission Planning and Cost Allocation in the West

If the West adopted independent, regional transmission planning beyond the purely voluntary approach of WestTEC – in line with approaches used in RTOs – projects could be selected for their broad system benefits rather than utility-specific needs. This could expand access to high-value generation locations, promote fairer (or at least *known*) cost allocation, reduce duplication, and potentially lower overall grid costs through more efficient transmission/generation system build-outs than today's uncoordinated processes allow. Over time, the development of a regional transmission planning and cost allocation service in the West could reduce siting bottlenecks for developers and provide buyers with access to a broader, more efficiently delivered portfolio of resources. A joint transmission planning and cost allocation service could, therefore, represent a meaningful opportunity for the West. This regional service might build on the efforts of WestTEC and the Western Transmission Consortium, although the longstanding split between transmission owners subject to FERC jurisdiction and those outside of it has made transmission planning and cost allocation a perennially difficult reform to implement in the West.

IV. Conclusion

The missing market and grid functions in the West – elimination of contractual transmission operation/control/service barriers; providing transparent, durable market prices; providing independent transmission planning; creating a consistent RA construct; and development of a consistent, independently overseen interconnection process – are attainable. These functions are the structural tools used successfully in other regions in the U.S., Canada, and Europe that make project development more predictable and efficient, which in turn expands competition and delivers lower electricity costs to consumers.

The West has taken real steps forward with WestTEC, RA programs like WRAP, and the development of day-ahead markets. But without the incremental functions discussed herein, project developers, wholesale buyers, and, ultimately, retail customers will continue to face higher costs and fewer options than they should.

Policymakers and regulators considering the next phase of Western electricity reform should focus on the **functions**, not just the institutional form. While RTOs provide the most complete and integrated model in other parts of North America, the real policy goal should be to ensure that the West gains access to the missing functions that can make project development more efficient, competition more robust, and electricity delivery more cost-effective across the region.

1. **Consolidate transmission operations and control.** The West should move deliberatively beyond contract-path transmission service, eliminate pancaked rates, and adopt flow-based or network-based transmission management that incorporates financial transmission rights. Consolidated transmission tariffs, consolidation of transmission operations/control, and additional day-ahead market reforms (coupled with revisions to certain programs/requirements that currently rely on contractual transmission service) could offer this benefit to participants in the West. This reform may also, as a practical matter, result in consolidation of BAs in the West, which could offer additional reliability and cost savings benefits to customers, but BA consolidation is not essential to achieve material benefits. First-mover states or transmission owners could form small critical masses of contiguous, consolidated transmission networks to pilot this important reform.
2. **Standardize interconnection processes.** The West can create consistent, independently operated interconnection processes. Developers currently are required to navigate through dozens of inconsistent interconnection rules and interconnection processes, each of which is managed by an incumbent utility which may have incentives to favor generation developed by itself or an affiliate over generation from an independently owned third party. A consistent, independent interconnection process across a broad footprint could reduce costs and improve predictability for new generators in the West. To initiate this effort, utilities in the same general region of the grid should begin discussing consolidation of their interconnection processes or could be encouraged to do so by their regulators.

3. **Advance price transparency and market durability.** Decision-makers should support the development of organized markets that go beyond short-term energy trading. This would include the incorporation of ancillary services into the day-ahead markets to improve price transparency and provide visibility into the full value of different locations on the grid. It would also include making the day-ahead energy market structures more durable and comprehensive, so that they could be counted on and provide a foundation for different types of contracting, including PPAs and the virtual PPAs used by corporate buyers in regions with RTOs. Both day-ahead markets should facilitate open discussions about market enhancements that could increase the range of services co-optimized by the market and could provide greater assurances of market participation that might support virtual PPA contracting.
4. **Continue to pursue RA programs.** The West should continue to pursue the development of RA programs via WRAP and the EDAM-focused RA program. These programs should provide clear information to project developers around the value their capacity offers and be designed in a manner that allows for entities to structure contracts to share and trade capacity value in a beneficial manner. Further evolution might include the formation of a voluntary, residual capacity market to facilitate more liquidity for capacity, stronger linkages with organized market functionality, and the elimination of specific source-to-sink firm transmission delivery requirements.
5. **Promote independent, regional transmission planning.** Transmission planning should be performed by an independent entity with the authority to evaluate regional needs, select projects, and allocate costs fairly among beneficiaries. This planning should be performed across a wide geographic area to help ensure the areas with the most efficient and cost-effective generation can be accessed by electricity buyers in the West. The West should evaluate what lessons to learn from WestTEC's initial non-cost-allocated studies, strong stakeholder process, and funding model, and how to address the divided nature of FERC-jurisdictional versus non-jurisdictional transmission owners. And stakeholders could begin to explore whether there is any appetite for expanding WestTEC, or creating adjunct entities, to develop a process that incorporates some form of binding requirements or otherwise addresses cost allocation for new transmission, including a workable cost allocation mechanism for transmission providers not subject to FERC jurisdiction. Promising vehicles for multilateral transmission partnerships deserve regional support.

The West has never been afraid to do things differently. Its electricity system has worked sufficiently until recently to provide cost-effective and reliable service across the region. But the challenges ahead – rapid demand growth, ambitious clean energy goals, maintaining reliable service, and rising costs – require tools that the current model does not provide.

Incremental reforms implemented to date and planned for the coming years have been valuable, but they leave critical gaps. Filling those gaps with the missing functions described in this paper would make it easier for developers to bring new projects online, expand the pool of buyers, and deliver lower costs and greater reliability for consumers. Whether through an RTO or another more incremental model, adopting these functions over a sufficiently large footprint would expand competition, improve reliability, and deliver lower-cost power to customers.

To capture the full benefits of a more integrated Western power system, utilities, regulators, and other stakeholders in the region should begin to prioritize the development of the reforms discussed herein. While many of these reforms will require long-term coordination, meaningful progress could begin with smaller groups of willing utilities and transmission owners – along with their regulators, transmission customers, and other stakeholders – working together to consider these reforms and test their viability at a smaller scale. For instance, a group of relatively contiguous transmission providers could begin discussing tariff consolidation and considering whether the transfer of operational control of their transmission systems to an independent entity would be viable. A similar approach to consolidating generator interconnection processes could be undertaken. Reforms to electricity markets, RA programs, and transmission planning, on the other hand, may make more sense to pursue through the existing forums for those services where utilities, IPPs, marketers, and other stakeholders could begin exploring high-value enhancements, such as integrating ancillary services into day-ahead markets, making day-ahead markets more conducive to long-term contracting, improving regional RA programs (especially with respect to transmission delivery requirements), and considering further enhancements or expansion of regional transmission planning. Beginning with these steps could help put the West on a path to obtaining the significant value that remains available from greater regional collaboration in the region.

The West does not need to abandon its tradition of incrementalism. But it does need to advance further reforms. Launching day-ahead markets is an important but only partial and insufficient reform. Advancing this package of reforms, or any significant portion of them, will deliver demonstrable value. The choice before policymakers is not whether the system will evolve, but how to put in place the functions that will shape the next generation of Western electricity.

Appendix: The Regulatory Origins of RTOs and ISOs

A remarkable aspect of the structure of the U.S. wholesale power and gas sectors is the degree to which administrative (rather than legislated) innovation has occurred through FERC and FERC-blessed initiatives, often in parallel to voluntary industry innovation. This innovation has extended to fundamental matters such as market-based rate authority and the creation of RTOs. This history suggests a wide degree of latitude for the West to come up with more bespoke Western solutions that supply the regional functions described in this paper.

In 1996, FERC issued Order 888, a kind of magna carta for a restructured wholesale market. The order (along with Order 889, issued the same year) established what are now bedrock principles: open access to transmission; at minimum, functional unbundling by transmission providers of generation and transmission functions; and a regulatory blessing for a form of third-party grid operator – the "independent system operator" (ISO) – who would be independent from the financial interests of any existing market participant. Independence from transmission owners in particular, who can otherwise block access to the grid by other market participants, was a central aspect of FERC's promulgation of ISOs. ISOs would own neither generation nor transmission assets; they would merely operate the system owned by others.

In 1999, as the initial momentum of wholesale market restructuring waned, FERC issued Order 2000 in order to encourage the further evolution of larger independent grid operators, both by improving and consolidating existing ISOs and by forming new organizations from scratch. FERC's order focused in particular on persistent problems with transmission access and market power that compliance with Order 888 had not solved, especially in areas in which ISOs had not been established. Order 2000 was a spur rather than a mandate, building on the initial encouragement for ISO formation that FERC had provided in Order 888. Order 2000 set more explicit minimum characteristics and functions that were lacking in Orders 888 and 889 for a new entity that FERC named a "regional transmission organization."

Order 2000 contemplated a number of different types of independent transmission-focused entities that could meet its standards, including ISOs, independent transmission companies ("transcos"), hybrid combinations of ISOs and transcos, and "new organizational forms not yet discussed in the industry." Transcos could be both for-profit and non-profit; they would directly own or lease transmission and be responsible for maintenance, operations, planning, and new construction. FERC indicated that it would reserve the option to apply a more compulsory approach to RTO formation on a case-by-case basis upon review of proposed industry mergers and acquisitions, market-based rates, and remedies for undue discrimination stemming from the unmitigated market power of transmission owners. FERC also previewed a plan to accept incentives, such as rate-of-return "adders," for transmission owners who joined an RTO. The order comprised mostly carrots and had few sticks.

Order 2000 was, in some ways, the high-water mark of FERC's success in spurring the creation of regional organized markets. It was still fundamentally a voluntary approach to the formation of an independent grid operator. Multiple voluntary efforts foundered after Order 2000, including a proposed consolidated RTO in the Northeast that joined New York, New England, and PJM's footprint; RTOs in both Florida and other parts of the Southeast; and similar efforts in the West outside California. The RTO formation efforts in the West were deeply undermined by the 2000-2001 Western energy crisis that stemmed from a rushed effort to restructure California's wholesale market, resulting market design flaws (some of which were manipulated by some market participants), a West-wide capacity shortage exacerbated by a Northwest drought, and the failure of policymakers in California and at FERC to intervene quickly to mitigate the crisis.[53] In 2002, when FERC pursued a more mandatory RTO tack with a rulemaking on "standard market design," the attempt largely backfired as advocates of local and state control of the power sector resisted.

Ultimately, the only new independent grid operator to obtain FERC approval (to date) after Order 2000 was SPP. The other five FERC-regulated grid operators already had approval or conditional approval as ISOs from FERC before Order 2000, although several significantly expanded their footprint and service offerings in the 2000s, and MISO's launch was spurred by Order 2000.[54]

Today, there is no meaningful distinction between an RTO and an ISO, including with respect to originating generation and storage projects, the focus of this primer. Put simply, RTOs cover more than one state and emerged directly out of the initial organizational phase of ISOs. The convention at FERC and in the industry is to refer to them interchangeably as RTO/ISOs and, for the sake of convenience, often simply as RTOs.

The two independent grid operators in the U.S. that are still technically ISOs and not RTOs under FERC's Order 2000 standards are in New York and California, in part because they remain single-state markets (Order 2000 required a sufficient "Scope and Regional Characteristic" that FERC found the NYISO failed to meet; CAISO's filing to obtain RTO status was suspended by FERC in 2005 following the Western energy crisis fallout and a litigious dispute about CAISO's governance). ERCOT is also an ISO and not an RTO, but ERCOT is also not subject to FERC's jurisdiction.[55]

It is worth emphasizing that the single-state ISO model is only in effect in three of the four largest states by population. While a single-state independent grid operator could be an option for some states in the West, given the relatively small population of each state, a

[53] Each of these contributing factors has been substantially addressed in the subsequent twenty-five years, including through the redesign of CAISO and the markets it operates, the creation of new RA standards (e.g., WRAP), and the strengthening of FERC's Office of Enforcement, with associated new market manipulation and penalty authority, at the direction of Congress in the Energy Policy Act of 2005.

[54] MISO and ISO New England retained the ISO in their names, an artifact of their original organization, even after receiving FERC's approval as RTOs.

[55] FERC has recognized ERCOT as an ISO. *E.g., Houston Lighting & Power Co., Texas Utilities Electric Co.*, 81 FERC P61,015, at 61107 (1997) (discussing how Texas state requirements for ERCOT compare favorably to FERC's).

truly regional grid operator that covers multiple states is an obvious choice for providing new services in the West.