Public Utilities Commission

COLORADO PUBLIC UTILITIES COMMISSION

COLORADO TRANSMISSION COORDINATION ACT: INVESTIGATION OF WHOLESALE MARKET ALTERNATIVES FOR THE STATE OF COLORADO §§ 40-2.3-101 to 102, C.R.S.

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Table of Contents

Table of Report Figures

Table of Report Tables

EXECUTIVE SUMMARY

This study, conducted by the Colorado Public Utilities Commission (Commission or PUC) as part of the Colorado Transmission Coordination Act (CTCA), finds that enhanced market participation through greater regional coordination can reduce total annual costs for Colorado electric utilities by as much as 4 to 5 percent, while helping to accelerate the achievement of our state's clean energy goals. At the same time, this investigation also identifies significant concerns with shifting core aspects of electric utility regulation (involving new generator interconnection, transmission expansion, and resource adequacy) from state control to regional processes due to significant governance issues. The determination that it is in the public interest to transfer functional control of Colorado's electric utility transmission assets to a broader regional process would require consideration of those governance issues and certain other concerns in the context of a specific market opportunity. In the meantime, Colorado's electric utilities should actively explore alternative market opportunities to deliver the benefits of enhanced regional coordination while limiting the concerns identified in this study.

A. Overview

The CTCA, part of Senate Bill (SB) 19-236, directed the PUC to investigate the costs and benefits of Colorado utilities participating in an organized wholesale market in the form of an energy imbalance market, joint tariff, power pool, or regional transmission organization. More recent legislation, SB21-072, requires all Colorado transmission utilities to "join an organized wholesale market on or before January 1, 2030" clarifying the long-term direction to the PUC and the Colorado electric transmission utilities.

Through its CTCA investigation, the PUC has received multiple rounds of stakeholder comments, systematically reached out to regional thought leaders, sponsored a comparative study quantifying the costs and benefits for Colorado of participating in different market constructs, reviewed other third-party modelling studies, held a public comment hearing, and conducted deliberations seeking to determine the best path forward for Colorado in terms of enhanced regional coordination.

This investigation has played out in the context of a statutory framework that requires Colorado's electric utilities to reduce their greenhouse gas (GHG) emissions by 80 percent from a 2005 baseline by 2030 and 100 percent by 2050. Other statutory provisions obligate the PUC to realize these clean energy goals in an economically responsible manner that benefits all customers and maintains a safe and reliable electric grid. In the long-term, enhanced regional market coordination could significantly help Colorado achieve these goals.

This investigation, as well as any effort to enhance regional coordination in the West, also has to account for the structure of the existing transmission grid. In the West, there are currently 38 separate balancing authorities, individual utility transmission rates that pancake on top of each other, and contract path transmission approaches that bear little relationship to actual energy flows. Given all these significant shortcomings, a transition to a broader market structure in the West should consider consolidation of balancing authorities, the de-pancaking of transmission rates, and a shift towards flow-based transmission approaches.

Significant progress towards regional coordination has already occurred in the West. The California Independent System Operator (CAISO) Western Energy Imbalance Market (WEIM) has consolidated and optimized real-time dispatches across 84 percent of the load in the West and created an estimated $1.72 billion in benefits over the past ten years.[1] CAISO has also begun to implement flow-based transmission approaches. More recently, the Southwest Power Pool (SPP) has begun similar reforms, resulting in similar, if significantly smaller, benefits in the eastern side of the grid through its Western Energy Imbalance Service Market (WEIS).

In this environment and given the alternatives likely to be available to Colorado electric utilities, this investigation has carefully quantified the potential benefits of markets for lowering the capital and operating costs of the generation system in ways that allow for the enhanced integration of low-cost clean energy resources. This investigation has also considered the possible negative impacts associated with shifting state control over core generation, interconnection, and transmission decision-making, which have generally worked well in Colorado, to regional approaches that may currently be ineffective.

B. Findings

The quantitative analysis for this investigation concludes that markets have the potential to deliver substantial economic benefits through reduced operation and investment costs. Participation of Colorado electric utilities in an Energy Imbalance Market (EIM) could deliver on the order of $50 million in annual savings to Colorado (approximately 1 percent of a total annual Colorado electric revenue requirement of $6 billion). Full participation by the electric utilities in a Regional Transmission Organization (RTO) could deliver approximately $230 million annually or 4 to 5 percent of the total annual revenue requirement. A Day Ahead (DA) market construct, similar to a regional power pool, could deliver savings somewhere between these two options, depending on the exact market services included.

These kinds of savings were generally found to exist independent of whether Colorado looked west to the CAISO, east to SPP, or created something new in the middle working with neighboring utilities. As such, the quantitative study concludes that the key to obtaining these benefits was effectively participating in a broader market footprint, but it didn't matter so much which one.

[1] https://www.westerneim.com/Documents/ISO-EIM-Benefits-Report-Q3-2021.pdf

i. CAISO

CAISO would appear to be particularly well-suited to lead the effort to expand regional coordination since it already optimizes real-time imbalance energy over 84 percent of the western footprint. CAISO has proven that regional markets produce quantifiable savings, has taken the lead in flow-based transmission approaches, and is making progress on GHG emissions tracking. CAISO is also moving forward to create a day ahead market (DAM) that creates even greater benefits by optimizing day ahead unit commitment and dispatch and promoting more effective resource sharing.

Despite this potential, significant concerns remain about the long-term ability of CAISO to lead any organized wholesale market (OWM) outside of California. Effective control of CAISO is vested in a board of directors and a stakeholder process that is effectively controlled by the State of California. Given this governance structure, the risk exists that CAISO could protect California's parochial interests at the expense of what is best for the region. Recent filings by CAISO surrounding a "wheel through" tariff, which was approved by the Federal Energy Regulatory Commission (FERC) earlier in 2021, appears to have significantly exacerbated and given substance to these concerns.

The CAISO potential to encourage regional coordination is further clouded by resource adequacy issues and shrinking reserve margins in California, which have already delayed DAM implementation and distracted from broader efforts to promote regional markets. Until California addresses its resource adequacy issues, which may be getting worse, electric utilities in states like Colorado will likely need to be cautious about shifting control of their transmission assets to a process controlled by California.

Finally, in the near-term, a CAISO market option raises additional concerns specific to Colorado as several Colorado electric utilities and three Western Area Power Administration Balancing Authority Areas (BAAs) are participating in the SPP WEIS and are evaluating SPP expansion into the Western Interconnection. These actions create market seams and other short-term dispatch and coordination issues within Colorado. More recently, in April 2021, Colorado Springs Utilities (roughly 5 percent of Colorado load) announced that it will leave the Xcel Energy Colorado BAA to join a Western BAA and the SPP WEIS because of concerns with issues surrounding resource diversity and CAISO governance. This shift will exacerbate intra-state dispatch, curtailment, and resource sharing issues.

ii. SPP

SPP is expanding its WEIS market, moving forward with its own day ahead Markets Plus initiative, and proposing a full RTO structure in the West. SPP offers Colorado electric utilities some other critical advantages as compared to CAISO (and other full RTOs like ERCOT or PJM) in that states maintain control over resource planning and acquisition by their electric utilities, which has historically been well run in Colorado, creating considerable customer benefits.

In the short-term, broader participation in the SPP WEIS could also help improve intra-state Colorado dispatch and curtailment issues, while providing time to work on seams coordination issues that may arise across the state. And, like participation in other EIMs, the costs associated with entering and exiting the WEIS are low relative to more integrated markets.

However, the current governance of the WEIS – with substantial voting rights vested in individual power marketing agencies and cooperatives, with little opportunity for regulators to meaningfully participate – could create concerns for new utility entrants. These concerns may be exacerbated given cost allocation approaches based on load, which could harm new entrants with higher peak demands and less transmission. Under these circumstances, any short-term decision regarding market participation should consider the impact of entry and exit costs and the benefits of maintaining flexibility.

An SPP RTO may also raise longer-term governance concerns beyond the WEIS. In the West generally, and in Colorado particularly, robust and open stakeholder participation processes are considered integral to successful operation, while the SPP stakeholder participation processes appear less open, especially to non-regulator interests. In Colorado, PUC oversight of electric utilities is clearly defined and directly aligned by statute with the state's clean energy goals. In contrast, joining SPP may transfer control of key decisions to regional entities with interests that may not fundamentally align with Colorado's statutorily mandated economic and environmental goals. Similar to the WEIS, these concerns may be exacerbated given transmission cost allocation approaches based on load, which could harm new entrants with higher peak demands and less transmission.

Other longer-term concerns with an SPP RTO involve the process to allocate scarce interconnection access. In Colorado, interconnection access is currently awarded to the winning bidders in a competitive resource acquisition process. This approach allows Colorado utilities to bring online the lowest cost resources and, through offtake contracts, flow the benefits directly to native load customers. In contrast, interconnect queues in SPP are currently overwhelmed, with over 100,000 MW of queue filings in a 50,000 MW peak demand system. Although Colorado and an SPP-run RTO in the West would have the opportunity to start fresh, it is possible that the supply-demand problem could be even worse in Colorado given the underlying solar and wind resource economics. The inability to fairly and efficiently allocate interconnect to low-cost generators could delay new low-cost clean energy from coming online and would offer no direct mechanism for flowing the benefits through to native load customers.

A similar concern exists with transferring state oversight of electric utility transmission expansion to an SPP-run regional process. Colorado currently has the ability to quickly and cost-effectively construct new intra-state transmission through a utility-led process subject to PUC oversight. In SPP, however, transmission expansion often depends on the resolution of difficult-to-solve regional cost allocation issues and other disputes among competing interests. The end result is that needed, cost-effective new transmission may be significantly delayed or left unbuilt.

iii. Overall Approach

The determination that it is in the public interest to transfer functional control of Colorado's electric utility transmission assets to either CAISO or SPP requires resolution of existing core governance issues. Certain interconnection, transmission expansion, and resource adequacy concerns must also be addressed. In the meantime, Colorado's electric utilities should take advantage of other opportunities to work with our neighbors to explore consolidation of BAAs, to de-pancake transmission rates, to shift toward flow-based transmission approaches, and to optimize short-term intra-state dispatch in Colorado, all while participating with the other regional utilities to develop regional market options.

C. Next Steps

Between now and the 2030 statutory requirement in SB21-072 to join an OWM, along with working to address the concerns in this report, Colorado electric transmission utilities should be exploring potential market options in the short-term. Alternatives such as EIM and Day Ahead Market (DAM) may deliver fewer, but still substantial benefits, raise less concerns, and would allow utilities to build market experience and expertise. Imbalance markets provide the least benefits but also the fewest entanglements as the EIM is limited to intra-hour balancing. The DAM construct has the potential to provide substantially more benefits but is still in the early stages of formation, so the exact benefits and tradeoffs are less clear.

The DAM concept appears promising. The DAM concepts currently being developed in the West – by both CAISO and SPP – likely will include day ahead unit commitment, real-time balancing, optimization of ancillary services, and potentially planning and operating reserve margin sharing. These market services lead to enhanced system reliability and renewable integration in ways that are similar to a full RTO. At the same time, the DAM construct maintains existing planning and interconnection processes at the state level, in ways that limit governance concerns and avoids issues regarding transmission cost allocation.

Colorado utility participation in various processes designed to improve the status quo and enhance regional coordination in the West such as the Western Resource Adequacy Process (WRAP), Western Market Exploratory Group (Western MEG), and the FERC Advanced Notice of Proposed Rulemaking (ANOPR) process are all important next steps. Collectively, these processes have the potential to improve resource adequacy, consolidate western balancing authorities, start de-pancaking transmission rates, shift to flow-based transmission approaches, and improve interconnect queue management and transmission cost allocation processes. Although the exact order in which to address each issue is not obvious, progress needs to occur along multiple fronts in order to obtain the benefits of enhanced regional coordination.

Under these circumstances, one near-term course for Colorado's transmission utilities may be to participate in an EIM to resolve intra-state dispatch issues and to capture the enhanced near-term coordination benefits but preserve the flexibility to adjust as regional market opportunities in the West evolve (*e.g.,* by limiting upfront costs, negotiating reasonable exit fees, etc.). This approach can enable Colorado's utilities to meaningfully continue discussions with other western stakeholders to evaluate how competing DAM and or other market structures can provide substantial additional benefit to Colorado over time, while also contributing to western efforts to improve the status quo and address existing concerns with the existing alternatives.

D. Conclusion

Given the wide range of potential public interest considerations and uncertainties associated with evolving regional market opportunities in the West, the Colorado PUC must coordinate with other regulators in the West. The dispersed nature of the governance problem, the lack of an obvious solution, and the diversity of discussions in the West could all benefit through expanded leadership from state regulators.

As part of this effort to provide leadership in a rapidly evolving regulatory and market environment, the PUC intends to open a rulemaking proceeding in 2022 to ensure that customers and the public interest are protected during the transition to a full organized wholesale market that may ultimately shift state control over key decisions to regional processes. This rulemaking will also further investigate regional market issues and make sure that the Colorado electric utilities are treated in a way that acknowledges the utility's situation-specific circumstances.

Overall, enhanced coordination and participation in regional markets will accelerate the clean energy transition in Colorado and more broadly in a way that benefits all customers and maintains a safe and reliable electric system.

I. INTRODUCTION

Under the 2019 CTCA, the PUC was directed to investigate the potential costs and benefits of Colorado utilities participating in various regional market structures and to make a public interest determination about the best path forward. [2] Subsequent 2021 legislation requires Colorado's transmission utilities to join an OWM by January 2030, while allowing the PUC to waive or delay this requirement in certain circumstances.[3]

A. Legislative Background

The CTCA was one piece of a larger statutory framework that seeks to decarbonize Colorado's energy system in a way that benefits all customers and maintains a safe and reliable network. The CTCA requirements were part of SB19-236, which also established requirements for Public Service Company of Colorado (PSCo or Public Service)[4] to file a Clean Energy Plan (CEP) designed to reduce GHG emissions by at least 80 percent relative to a 2005 baseline by 2030. The bill also requires that CEPs seek to achieve 100 percent clean energy[5] by 2050 and allows other utilities to voluntarily file a CEP.[6] The "80 by 30" goal has become the guiding principle for much of the Commission's work in generation and transmission resource planning, transportation and building electrification programs, rate design, and establishing utility financial incentives.

House Bill (HB) 19-1261 established economy-wide GHG emission reduction targets. This Climate Action Plan to Reduce Pollution set the following targets relative to the 2005 historical GHG emission levels:

- 26% reduction by 2025
- 50% reduction by 2030
- 90% reduction by 2050

The Governor's Colorado Energy Office (CEO) and other state agencies collaborated to produce Colorado's *Greenhouse Gas Pollution Reduction Roadmap*, released January 14, 2021.[7] The Roadmap indicates that in addition to Public Service which is required to file a CEP, Black Hills Colorado Electric, LLC (Black Hills), Colorado Springs Utilities, Platte River Power Authority, Holy Cross Electric Association, Inc. (Holy Cross), and CORE Electric Cooperative have voluntarily committed to filing a CEP. Furthermore, the Colorado

[2] Colorado Revised Statues, Section 40, Article 2.3.

[3] Senate Bill 21-0072.

[4] Public Service is a subsidiary of Xcel Energy Corporation.

[5] Clean energy generates or stores electricity without emitting CO_2.

[6] House Bill 21-1266 expanded the CEP requirement to include Tri-State Generation and Transmission Association, Inc. *See* §§ 25-7-105(1)(e)(VIII)(I) and 25-7-105(1)(e)(VIII)(J), C.R.S.

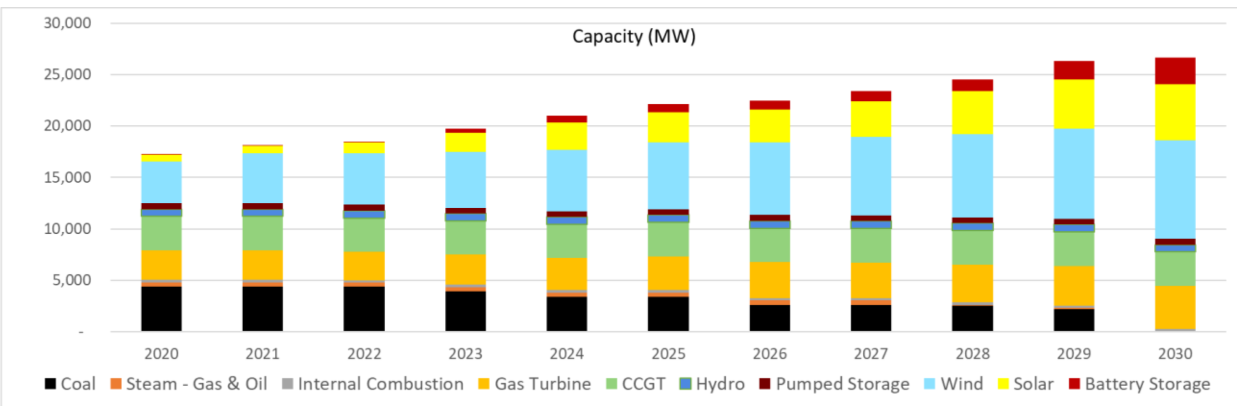
[7] https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap

Air Quality Control Commission's GHG reduction target for the electricity sector equates to every electric utility achieving the 80 percent reduction from 2005 levels by 2030.[8]

B. The Path to 2030 and 80 Percent GHG Emission Reduction

The path to an 80 percent reduction in GHG emissions from the electric sector will require substantial investment in new infrastructure. The Commission's analysis for purposes of the CTCA study suggests that, by 2030, the State of Colorado will need to develop new generation on the order of 5.5 GW of wind, 4.8 GW of solar, 2.6 GW storage, and 1.4 GW of gas generation in order to achieve its emissions reduction goal. Thankfully, Colorado is rich in renewable-energy natural resources such as wind and solar that appear to be sufficient to achieve the 80 by 30 goal, even without participation in an OWM, and in ways that have the potential to benefit all customers. In addition, the modeling suggests that such a transition can be accomplished with a reasonable impact to electricity rates.

Figure 1: *Reference Case Capacity Expansion in Colorado*[9]



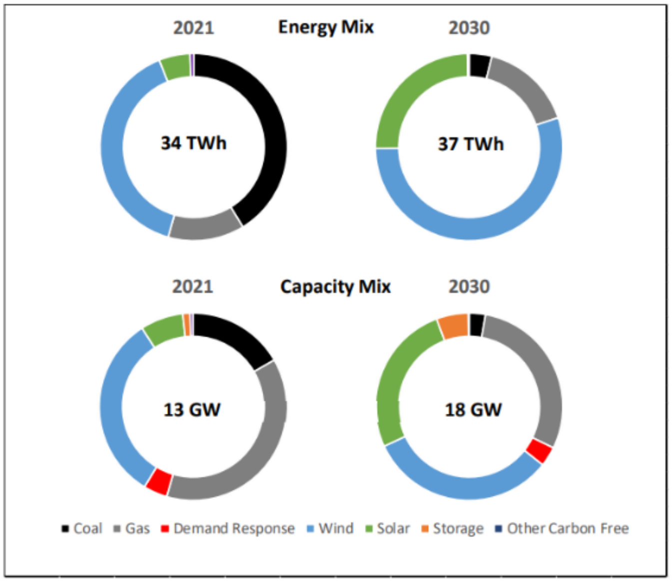
The Commission is currently evaluating Electric Resource Plans (ERPs) from both Public Service and Tri-State Generation and Transmission Association, Inc. (Tri-State).[10] These proceedings provide an opportunity for the Commission to examine the utilities' plans for compliance with the 80 by 30 target.

[8] Roadmap at 97.

[9] From Exhibit 37 of the "CTCA Evaluation of Market Alternatives" report conducted by Siemens Power Technologies International (Siemens PTI) on behalf of the Colorado PUC. The data presents one path to the state's 80 by 30 goals. Actual capacity expansion and retirement decisions are subject to the Commission's resource planning Rules and Proceedings. In addition, the modeling of capacity expansion did not consider alternative coal plant operations such as limited capacity factor or gas conversion.

[10] The PSCo ERP Proceeding is No. 21A-0141E. The Tri-State ERP Proceeding is No. 20A-0528E.

Figure 2 Projected PSCo 2030 Capacity and Energy Mix



Public Service, Colorado's largest investor-owned utility serving 1.6 million homes, filed its CEP with the PUC in March of 2021. The Company's proposed plan projects an 85% reduction in GHG emissions, and 80% renewable energy generation by 2030. The proposal involves nearly 4 GW of new wind and solar resources and early retirement of several of the State's remaining coal facilities.[11]

Tri-State, a wholesale generation and transmission utility serving 42 electric co-operatives across four states, submitted its ERP to the Colorado PUC in December 2020 and presented a preferred plan that by 2030 is estimated to achieve an 80 percent reduction from 2005 levels of CO2 emissions attributable to wholesale sales in Colorado. In addition to the 200 MW of wind and 700 MW of solar already slated to come online through 2024, Tri-State's preferred plan would add 800 MW more wind and 1,250 MW more solar through 2030, resulting in renewable generation comprising about 65 percent of Tri-State's Colorado wholesale sales. Tri-State has also proposed to retire all of its coal-fired generation in Colorado by 2030.

Under state law, Colorado is mandated to achieve even greater GHG emission reductions beyond 2030. SB19-236 requires CEPs to seek to address a 100 percent clean energy goal by 2050 and HB19-1261 targets 90 percent reduction in GHG emissions economy-wide by 2050. It is within this context that the Commission was directed to evaluate the costs and benefits of Colorado utilities participating in organized markets (CTCA) and that utilities were directed to join an OWM by 2030 through SB21-072.

[11] Figure AKJ-D-3 from the Direct Testimony of Alice K. Jackson in Proceeding No. 21A-0141E.

II. CURRENT AND ALTERNATIVE MARKET OPTIONS WITH ENHANCED REGIONAL COORDINATION

Enhanced regional coordination has the potential to provide significant benefits that could cost-effectively accelerate Colorado's clean energy transition through a number of mechanisms depending on the market construct. The CTCA statute identifies four types of market constructs for analysis. This section briefly describes each approach and re-orders and re-categorizes the constructs and analysis based on events that have occurred since the CTCA was enacted.

A. Status Quo: Bilateral Arrangements

Today, electric utilities in the State of Colorado, and most of the Western Interconnect, participate in traditional wholesale electricity markets where utilities are responsible for system operations, management, and planning. These utilities are typically vertically integrated, owning generation, transmission, and distribution systems to serve retail and wholesale electricity customers. In this context, wholesale physical power trade typically occurs through bilateral transactions between individual utilities, rather than through a centralized market clearinghouse.

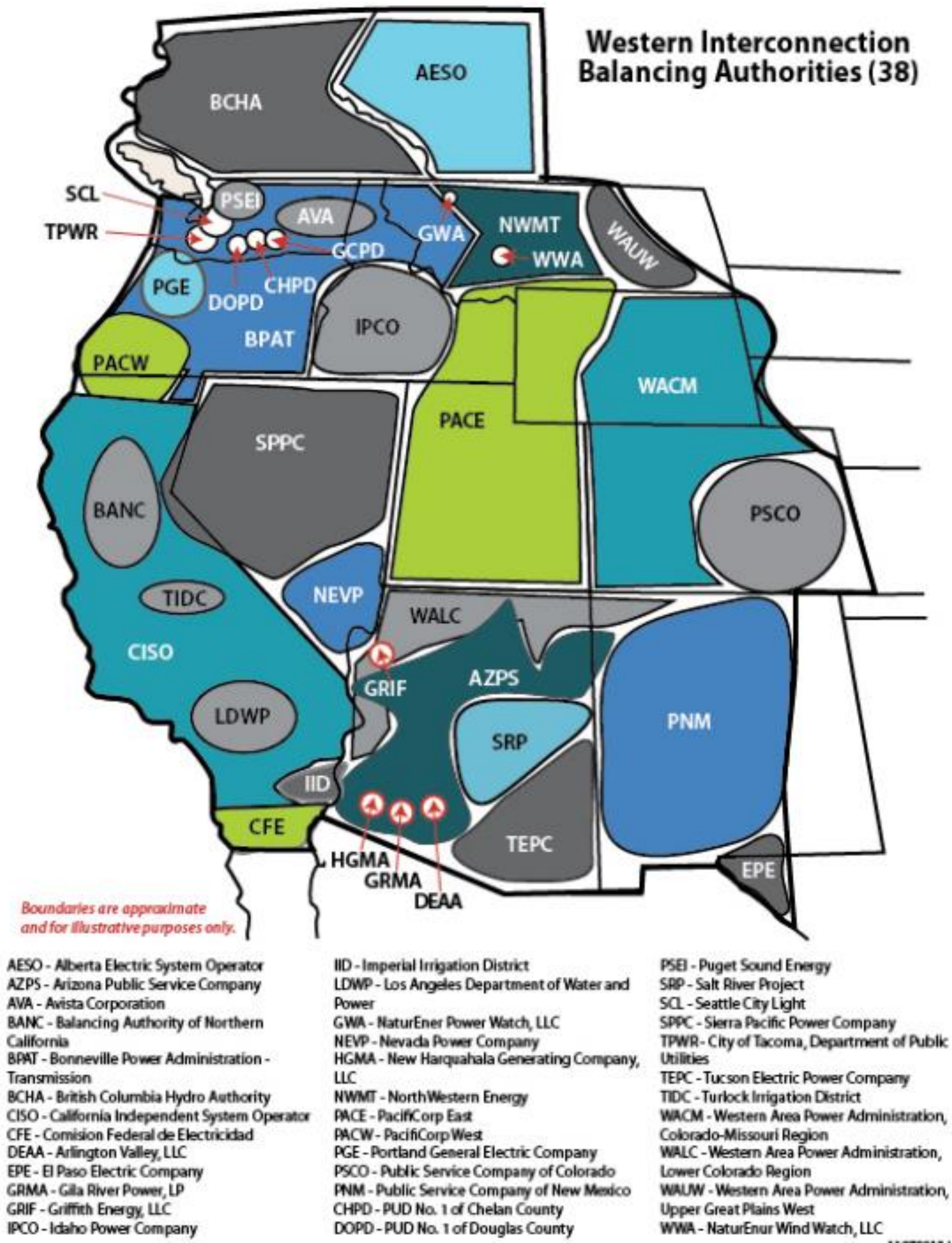
As shown in **Figure 3** below, the electric system is organized into BAAs whose administrators ensure that power system demand and supply are balanced in real-time. There are currently 38 BAAs in the Western - Utility (CSU). The utilities within the PSCo BAA operate under a Joint Dispatch Agreement (JDA), to dispatch their generating units on a sub-hourly basis to serve their combined load with the most economic resources.[12]

The current arrangement of BAAs with a small intra-state JDA has functioned well for Colorado up until now. Resource planning within Colorado is a nationally recognized success with robust competition for generation development.[13] Intra-state transmission planning and expansion is feasible and scarce interconnection access is awarded through a competitive process that immediately flows the benefits through to customers. Seams are managed (more or less) effectively through bi-lateral arrangements among the utilities and BAAs.

[12] FERC approved the JDA tariff on February 18, 2016 (154 FERC ¶ 61,107). The Commission approved PSCo's application related to the JDA on November 30, 2016 in Decision No. R16-1088 in Proceeding No. 16A-0276E.

[13] *See for example*: https://www.utilitydive.com/news/xcels-record-low-price-procurement-highlights-benefits-of-all-source-compe/600240/

__Figure 3__ Western Interconnect Balancing Authority Areas



Despite the fact that the status quo has historically functioned well, it has shortcomings that extend beyond Colorado throughout the entire West. Interest in regional markets is driven by the desire to capture the various potential benefits that result from greater market coordination. The clearest benefit from enhanced regional coordination is the greater operational efficiency derived from the optimization of generation and transmission resources across utilities. Resource optimization can result in short-term savings (intra-hour balancing), medium-term savings (day ahead unit commitment), and long-term savings (lower investment costs).

In addition, as states work to incorporate increasingly higher levels of non-dispatchable renewable resources, system operators look to greater regional coordination and geographic diversity. Regional market participation has the potential for increased access to renewable generation from other geographic regions and the potential to export local excess renewable generation without paying fees to multiple transmission providers (pancaked rates). Regional diversity of renewable generation may help compensate for the inherently intermittent nature of individual renewable resources, reduce curtailment of renewable resources, and help support the state's statutory requirements and energy policy goals.

B. Real-Time Energy Imbalance Markets

An EIM refers to a real-time power trading market that allows participants to buy and sell unscheduled energy using available transmission capacity, with transmission generally priced at zero cost. An EIM incorporates economic dispatch whereby generating resources are dispatched on a least cost basis subject to transmission constraints on a five-minute granularity. Regional real-time markets offer the benefit of enhanced regional dispatch over a broader footprint with more efficient intra-hour use of both generating assets and the transmission system, resulting in lower operating costs.

While EIMs provide real-time operational savings, they do not reduce the pancaking of transmission rates, do not enhance the commitment and scheduling of generating and transmission assets, and do not impact long-term planning processes.

In the West, there are currently two options for real-time EIM – the SPP administered WEIS and CAISO administered WEIM.

i. SPP WEIS

The WEIS began operation in February of 2021. Currently, entities within two BAAs are participating in the WEIS market: the Western Area Colorado Missouri (WACM) and the Western Area Upper Great Plains West (WAUW) BAAs. The eight participating entities[14] represent approximately 7,000 MW of generation in aggregate. The remaining entities having generation and/or load located within the WACM and WAUW BAAs are represented in the WEIS market by their balancing authorities. The BAA acts as a market participant for these entities, and any energy imbalances are settled by SPP with the participant. Resources of such entities are known as partial participation resources.

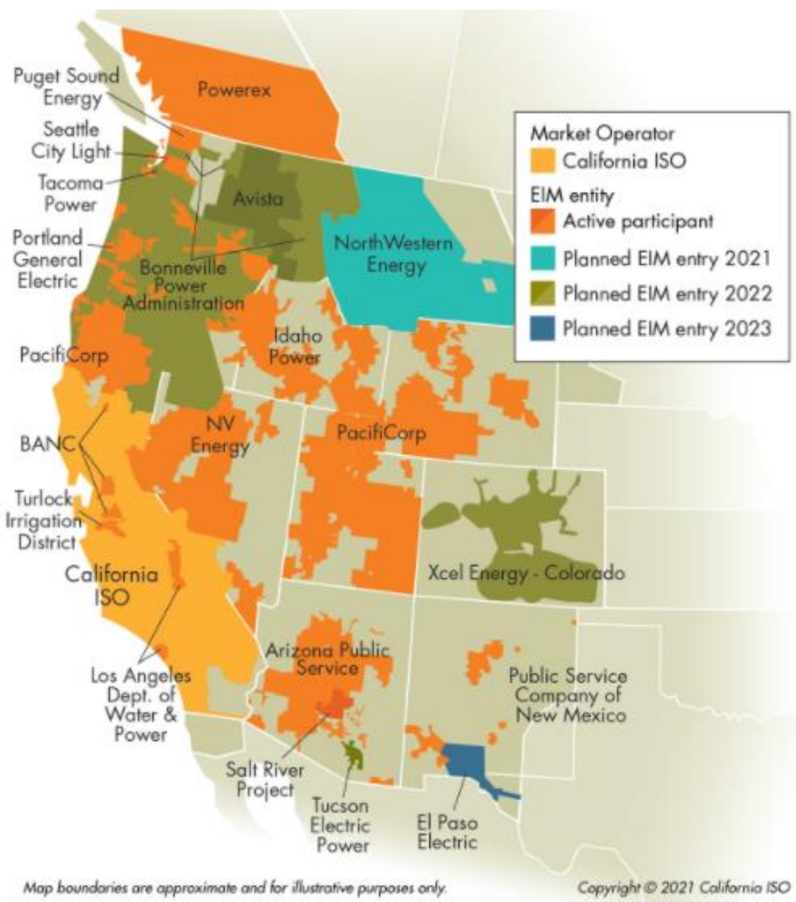
[14] Basin Electric Power Cooperative, Deseret Power Electric Cooperative, Municipal Energy Agency of Nebraska, Tri-State, Wyoming Municipal Power Authority, and three WAPA regions: Upper Great Plains, Rocky Mountain Region, and Colorado River Storage Projects.

Colorado Springs Utilities announced in May of 2021 that it would leave the PSCo-administered JDA to join SPP's WEIS. The press release quotes CSU CEO Aram Benyamin explaining the change:

> I'm excited for our customers to start benefiting from our participation in the Western Energy Imbalance Service Market. Our current portfolio of solar compliments SPP well… We expect to save customers money by optimizing the dispatch of different utilities' generating resources within each hour of the day. Our employees will also benefit from increased market intelligence, better integration of our new solar projects and being one step closer to meeting our clean energy goals.

ii. CAISO WEIM

Figure 4: *CAISO WEIM Footprint*



The California ISO has operated its WEIM since 2014 with founding members of the California ISO and PacifiCorp. Since then, the imbalance market has expanded to include 14 BAAs with an additional 8 BAAs committing to join over the next three years.

The most recent EIM quarterly report from Q3 of 2021 reports that "[g]ross benefits from EIM since November 2014 [are] $1.72 billion." In the third quarter alone, CAISO estimated benefits over $300 Million with a 9,862 metric ton reduction in CO_2 as a result of reduced renewable curtailments.[15][16]

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[15] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

[16] Benefits accruing to large entities of a similar size to PSCo, such as Arizona Public Service Company (APS) and Pacificorp, were $49 Million in 2020 and $49 Million to date in 2021 for APS and $40 Million in 2020 and $75 million to date in 2021 for Pacificorp.

Public Service Company had announced that it would join the WEIM, signing an implementation agreement on May 18, 2020 to enter the WEIM no later than April 1, 2022. However, on June 10, 2021, PSCo announced a pause in the implementation of WEIM participation after CSU announced its decision to switch to the WEIS. Public Service stated that "Xcel Energy remains committed to evaluating a regional market structure that will ensure system reliability and help integrate wind and solar energy… During the next year, we will continue to evaluate different market options that could reduce costs, increase reliability and help promote [Xcel's] carbon-free vision."

C. Power Pool / Day Ahead Markets

A Power Pool is a group of utilities that combine or consolidate some electric generation services. Services that could be included in a Power Pool consist of joint dispatch, energy imbalance, outage coordination, joint transmission tariff, and reserve sharing, among others. A power pool could be administered either by an independent party or by one of the participating entities.[17] The Extended Day Ahead Market (EDAM) is an initiative first conceptualized by CAISO and Western EIM entities to extend the benefits of the EIM to the day-ahead market. While not specifically called a Power Pool, the concept is similar.

As currently conceptualized, a DAM construct would enable day-ahead unit commitment and dispatch as well as real-time balancing across the participating footprint but would not encompass the transfer of operational control or any planning responsibilities to the administrator. A Power Pool or DAM could also include other services, such as the sharing of long-term planning reserve margin obligations and/or the de-pancaking of transmission rates through the implementation of a joint tariff. Sharing of planning reserve margins across a broader footprint could reduce the need for future generation investment.[18] And de-pancaking transmission rates through a joint tariff allows for more efficient use of the electric infrastructure. Such a market structure would retain state or utility resource adequacy requirements, interconnection queue management, seams coordination, transmission planning processes, and regulatory/governance structures.

Currently, there is no standalone DAM operating outside an RTO anywhere in the country. However, both SPP and CAISO have announced that they intend to develop such a market offering and the market concepts are in varying stages of development. It is as yet unclear what market services would be covered by either of these market options, but this approach could have the potential for Colorado to realize many of the benefits of enhanced regional coordination without shifting control of critical planning and operational issues to vague or as of yet undefined regional processes.

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[17] Initial Comments of Public Service Company of Colorado in Proceeding No. 19M-0495E, p. 3.

[18] For instance, Colorado's current reserve margin requirement is 18 percent while the reserve requirement in SPP is only 12 percent.

D. Organized Wholesale Markets / Regional Transmission Organizations

An OWM or RTO refers to an independent electric transmission operator that provides wholesale transmission services to more than one provider of electric services. An RTO incorporates centralized real-time dispatch and day ahead unit commitment with a joint transmission tariff. An RTO also consolidates reliability obligations, transmission planning and cost allocation, and transfers functional control of the transmission system to the system operator. "RTOs also typically administer markets for ancillary services (such as contingency and regulating reserves), function as reserve sharing groups, coordinate seams with neighboring footprints, and provide mechanisms for hedging congestion cost exposure."[19]

Currently, there are no RTOs operating in the Western Interconnection outside of California, though SPP is actively working to develop an "RTO-West" option. In November of 2020, WEIS members committed to evaluating joining the RTO-West and began negotiations. In July 2021, the SPP Board approved the RTO West policy level terms and conditions, establishing an expectation for financial commitments in April 2022 and RTO-West launch in March 2024.

RTOs represent incremental potential benefits over and above EIM and DAM structures, though the exact level of incremental benefits depends on the level of services provided by each specific market. RTOs generally include regional transmission rate de-pancaking, regional transmission planning and cost allocation, allocation of interconnection access, management of market seams, governance structures, regional operating and planning reserve margins, etc.

RTO participation involves the transfer of functional control of transmission assets as well as certain processes such as generating unit commitment and dispatch from the state to the RTO / FERC in ways that can produce both benefits and costs. This report analyzes the benefits and costs for Colorado in the next section of each of the various potential market options.

E. Other On-going Western Market Efforts

A series of other efforts are ongoing in the west, which collectively could – through enhanced regional coordination -- help improve the status quo in multiple areas including resource adequacy, consolidation of BAAs, de-pancaking of transmission rates, interconnect queue management, and transmission expansion.

i. Northwest Power Pool Western Resource Adequacy Program

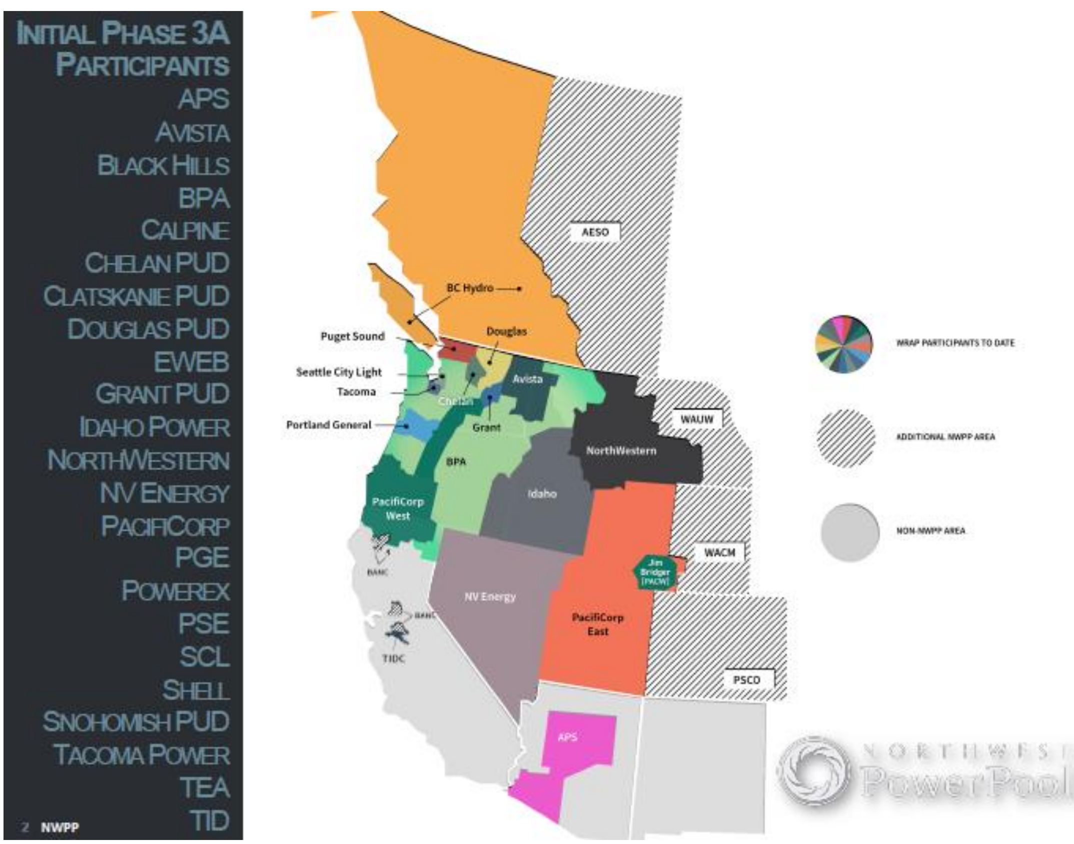
In addition to the CAISO and SPP Western Market initiatives, the Northwest Power Pool (NWPP) has been working since 2019 to design and implement a regional resource

[19] Initial Comments of Public Service in Proceeding No. 19M-0495E, p. 5.

adequacy construct -- the Western Resource Adequacy Program (WRAP). While not technically a “market,” this capacity-based program would go well beyond the current NWPP reserve sharing by leveraging load diversity to reduce planning reserve margins and enhance reliability and regional coordination. The WRAP design document describes the two-part program components. [20]

The Resource Adequacy (RA) Program design and implementation will have two components: an FS (Forward Showing) Program and an Ops (Operation) Program. The FS Program ensures the footprint has enough demonstrated capacity, well in advance of required performance, to meet the established reliability metrics. The Ops Program creates a framework to provide participants with pre-arranged access to capacity resources in the program footprint during times when a participant is experiencing an extreme event. An extreme event could be when a participant’s load is in excess of their FS forecast or resources (generation and transmission) are experiencing unexpected outages; this portion of the program unlocks the footprint’s load and resource diversity. The program seeks to achieve a balance between planning in a reasonably conservative manner but also to provide flexibility in order to protect customers from unreasonable costs.

***Figure 5:** Current NWPP WRAP Participation*



[20]https://www.nwpp.org/private-media/documents/2021-08-30_NWPP_RA_2B_Design_v4_final.pdf

Broad participation, including by state regulatory authorities, has been key to program development. In October of this year, state utility commission representatives jointly submitted comments providing detailed feedback and recommendations on program governance, hoping to create a regional model of effective governance.[21] The WRAP began operating Phase 3A on October 1, 2021. This is a non-binding forward showing program with 23 participants representing almost 65 GW of peak load. The schedule calls for full program operation by 2024.

ii. Western Markets Exploratory Group

In November of 2021, a number of western utilities, including most of Colorado's JDA members,[22] announced the formation of the "Western Markets Exploratory Group" or WMEG. A press release from Pacificorp states that the group is "exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing state regulations."[23] The group, which began discussions this summer, includes Xcel Energy-Colorado (PSCo), Arizona Public Service, Black Hills Energy, Idaho Power, NV Energy, Inc., PacifiCorp, Platte River Power Authority, Portland General Electric, Puget Sound Energy, Salt River Project, Seattle City Light, and Tucson Electric Power.

The press release further explains that the group is:

> in the early stages and… focused on developing long-term solutions to improve market efficiencies in the West. That includes incorporating lessons learned from existing regional markets as well as other efforts across the West… Many of the companies in the group are currently participating in, or preparing to join the California Independent System Operator's Western Energy Imbalance Market, or have announced plans to evaluate energy imbalance services. WMEG's discussions will not impact participation in or evaluation of those markets in the short-term, as the group is focused on long-term market solutions.

iii. FERC / NARUC Transmission Task Force

In June of 2021, FERC and NARUC (the National Association of Regulatory Utility Commissions) announced the formation of a joint Task Force to "ensure cooperation between federal and state regulators… on electric transmission issues… The Task Force

[21] https://www.nwpp.org/private-media/documents/NWPP-RA-Program-Governance_Written-Comments_FINAL_2021-10-15.pdf. See page 11.

[22] Colorado Springs Utilities is not participating in the WMEG but is still currently in the JDA.

[23] https://www.pacificorp.com/about/newsroom/news-releases/power-providers-explore-western-market-options.html

will focus on topics related to planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective."

The Task Force is comprised of all of the FERC commissioners as well as representatives from ten state commissions. The state representatives were selected with even representation across the country.

The FERC order establishing the Task Force identified the following objectives:

- "Identify barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers;
- Explore potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals;
- Explore opportunities for states to voluntarily coordinate to identify, plan and develop regional transmission solutions;
- Review FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identify recommendations for reforms;
- Examine barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and
- Discuss mechanisms to ensure that transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination."[24]

iv. FERC Advanced Notice of Proposed Rulemaking

On July 27th of this year, FERC issued an ANOPR titled "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator interconnection." This ANOPR signaled that FERC may soon consider broad reforms to various transmission issues. These topics include:

- Regional transmission planning and how to incorporate longer-term forecasts of transmission needs;
- Cost responsibility and how to identify and attribute benefits that are considered for cost-allocation purposes;
- Generator interconnection funding and changing how grid network upgrades are assessed, with the possibility that grid network upgrade costs will be allocated according to an upgrade's benefit rather than charged to the interconnecting generator;

[24] https://www.ferc.gov/news-events/news/ferc-naruc-establish-joint-federal-state-task-force-electric-transmission

- Generation interconnection queues, with proposed modifications focused on discouraging speculative interconnection requests and fast-tracking certain requests; and,
- Oversight of transmission planning and spending, potentially by an independent entity or involvement of state commissions.[25]

[25] https://www.ferc.gov/news-events/news/advance-notice-proposed-rulemaking-building-future-through-electric-regional

III. EVALUATING THE COSTS AND BENEFITS FOR COLORADO OF MARKET CONSTRUCTS FOR ENHANCED REGIONAL COORDINATION

As discussed above, the CTCA directed the PUC to investigate the costs and benefits of four specific market structures: 1) EIM; 2) Joint Tariff (JT); 3) Power Pool (PP); and 4) RTO. In addition, recently passed legislation, SB21-072 (40-5-108) required that "all Colorado transmission utilities shall join an Organized Wholesale Market on or before January 1, 2030." The legislation defines an OWM as an RTO or Independent System Operator (ISO) "established for the purpose of coordinating and efficiently managing the dispatch and transmission of electricity among public utilities on a multistate or regional basis."[26] While SB21-072 lays out a requirement for OWM participation, it also allows the Commission to grant a waiver or delay of the requirement if the PUC deems that participation is not in the public interest.

This section discusses the evaluation – both qualitatively and quantitatively – of the benefits of each market construct.

A. Overview of PUC Modeling Effort

As part of the investigation into the costs and benefits of various market structures, the PUC retained Siemens Power Technologies International (Siemens PTI) to conduct a study on the costs and benefits to electric utilities, other generators, and Colorado electric utility customers of alternative organized wholesale electricity market structures. This study included the evaluation of eight specific market structures, as represented in**Table 1**: Market Structures Analyzed below. Modeling was based on the 2020 through 2040 time period and all cases reflect the achievement of Colorado's GHG emission reduction goals.

The analysis focused on quantifying the benefits of EIM, the least integrated market option, and RTO,[27] the most integrated market option, across various potential geographic footprints. The study also included analysis of a combined Joint Tariff/Power Pool (JTPP) option that is roughly equivalent to the DAM construct but covering a much smaller market footprint. The JTPP option modeled did not include reserve sharing, so the results do not reflect any savings from reduced infrastructure investment. All modeling assumed that Colorado meets its GHG emission reduction goals of "80 by 30" and 90 percent reduction by 2040. The reference case assumes a continuation of the historical bilateral market arrangement and JDA with the current membership (*i.e.,* including CSU).

[26] § 40-5-108(1)(a), C.R.S.

[27] The RTO constructs modeled included a regional Joint Transmission Tariff.

***Table 1**: Market Structures Analyzed*[28]

Case #	Description	Day Ahead Market	RT Imbalance Market
1A & 1B	CO Reference	CO utility-level	Colorado JDA
1A & 2B	CO + WEIM	CO utility-level	WEIM
1A & 4B	CO + WEIS	CO utility-level	WEIS
1A & 6B	CO + Split WEIM/WEIS	CO utility-level	Split WEIM/WEIS
3A & 3B	WECC RTO	WECC RTO	WECC RTO
5A & 5B	SPP RTO	SPP RTO	SPP RTO
7A & 7B	Split RTO	Split RTO	Split RTO
8A & 8B	JTPP	JTPP	JTPP

B. Real-Time Imbalance Market Benefits

As described above, EIMs provide real-time benefits through the balancing of energy within the hour. Both the WEIM and WEIS offer intra-hour available transmission capacity at zero cost to optimize the operation of committed generating units based on real-time market conditions. This real-time market service may be offered as the only service, as with the WEIS and WEIM, or part of a more comprehensive market such as an RTO.

The Siemens modeling results reflect a consistent estimate of real-time balancing service benefits of approximately 1 percent of total system annual revenue requirement, regardless of market footprint or whether other services (*i.e.,* day ahead unit commitment) were offered. The average expected real-time market benefits are equivalent to $53 million annually, offset by administrative costs in the range of $1 to $12 million for net benefits in the range of $40 to $50 million.

[28] Siemens Study Exhibit 1.

Table 2: *Annual Savings from Provision of Real-time Balancing Services*[29]

Case #	Imbalance Market	NPV of Imbalance Costs ($2019M)	Savings vs. Ref.	Levelized Annual Savings ($2019M)	Total % Savings
1B	Colorado/JDA	$ 2,162			
2B	WEIM	$ 1,499	$ 663	$ 69	1.2%
4B	WEIS	$ 1,674	$ 488	$ 50	0.9%
6B	Split WEIM/WEIS	$ 1,661	$ 501	$ 52	0.9%
3B	WECC RTO RT	$ 1,514	$ 648	$ 67	1.2%
5B	SPP RTO RT	$ 1,845	$ 317	$ 33	0.6%
7B	Split RTO RT	$ 1,605	$ 557	$ 58	1.0%
8B	JTPP	$ 1,909	$ 253	$ 26	0.5%

The U.S. Department of Energy (DOE)-funded market study estimated the costs of imbalance market administration to be in the range of $0.01/MWh to $0.21/MWh. This translates to a range of $0.5 to $12 million for Colorado's retail sales of 56 million MWh. This range for fees is roughly consistent with other estimates of WEIM and WEIS administrative costs.

Along with the production cost and infrastructure investment benefits discussed above, markets can provide other system benefits that are harder to quantify such as enhanced reliability and renewable integration.[30] Several stakeholders referenced a FERC staff paper on the "Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Service"[31] as support for the reliability benefits of real-time markets. FERC Staff found that an EIM could provide reliability benefits through:

- "security constrained economic dispatch across the market footprint, which provides better management of imbalances and enhanced ability to manage flows within system operating limits, as well as enhanced opportunities to deliver energy from a diverse set of conventional and emerging technologies, such as demand response resources, for balancing;
- enhanced situational awareness;
- potentially fewer Energy Emergency Alerts;
- faster identification, dispatch and delivery of replacement generation after contingency reserve sharing assistance ends and for contingencies beyond reserve obligations; and
- assisting with the integration of variable energy resources."

[29] Siemens Study Exhibit 4.

[30] *See* Initial Comments of Public Service Company of Colorado filed on November 15, 2019 in Proceeding No. 19M-0495E at p. 7 stating "the benefits of markets are pronounced in regions with high penetrations of renewable resources. The ability to re-dispatch and displace traditional thermal generators every five minutes over multiple utility areas results in reduced curtailment of zero-fuel cost renewable energy, and hence lower production costs."

[31]https://www.westerneim.com/Documents/QualitativeAssessment-PotentialReliabilityBenefitsWesternEnergyImbalanceMarket.pdf

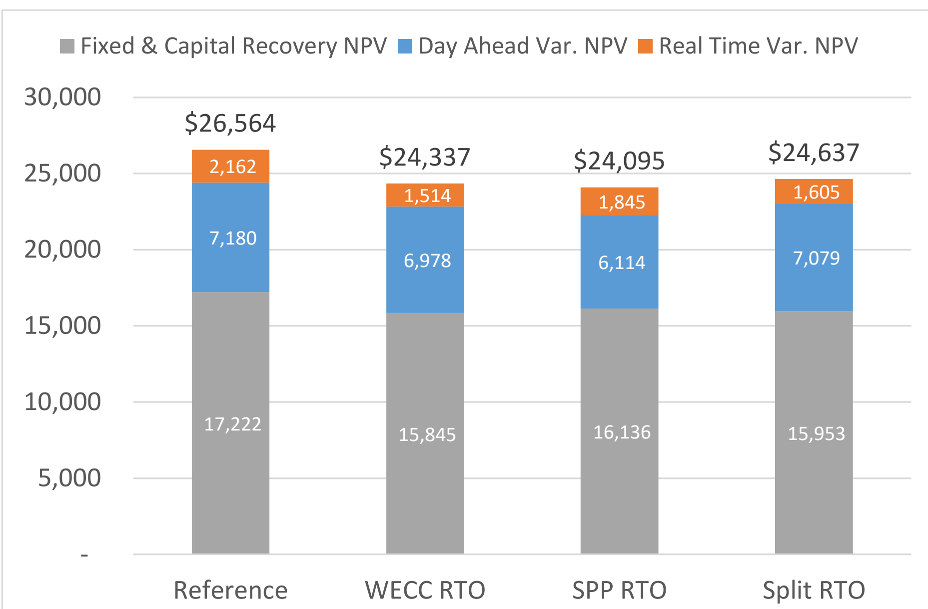
In its initial Comments filed on November 15, 2019, Public Service echoed those and other more qualitative benefits of market coordination. The Company stated:

> organized markets enable other qualitative benefits that are difficult to quantify as well, including (1) improved market transparency and price discovery, (2) independent oversight of market administration and participation, and (3) improved reliability through diversification of imbalances, enhanced situational awareness, and dynamic management of transmission system limits through sub-hourly nodal dispatch.
>
> Public Service Initial Comments at p. 8.

C. RTO Market Benefits

The Commission's quantitative study evaluated the operational and investment savings associated with RTO market services such as DA unit commitment, real-time energy balancing and reserve planning sharing services. This analysis estimated the NPV of the savings through 2040 to be $2.2 billion on average across the geographic market footprints modeled, equivalent to approximately $230 million per year of savings. Of these cost savings, approximately $1.2 billion is driven by reduced capital investment with an additional $0.5 billion in savings from each of real-time energy balancing and day ahead unit commitment services. These operational savings are balanced against administrative costs that may be in the range of $20 million to $50 million annually, for a net benefit from $180 to $210 million.

Figure 6: *Economic Benefits of Combined DAM and RT Services*[32]

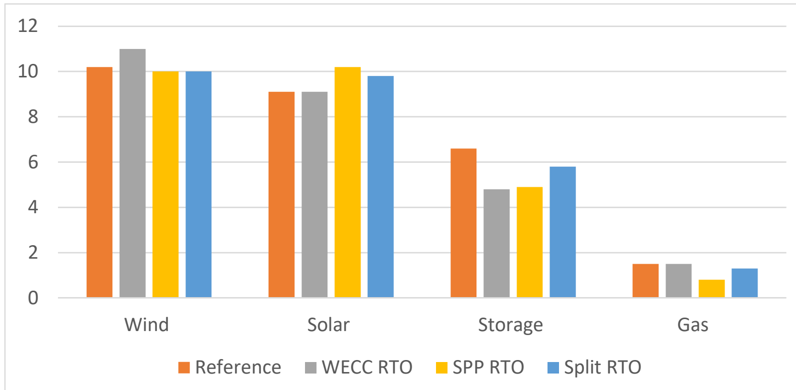


[32] Siemens Study Exhibit 5.

These total NPV savings are equivalent to approximately $230 million in annual savings or 4 to 5 percent of the total annual Colorado electric utility revenue requirement of $5.7 billion. However, this estimate does not include the cost of administering the organized market.

Figure 7: *DAM Capacity Expansion*[33]

RTO market participation results in a different mix of generation investment. Savings are driven primarily by a lower need for storage resources due to the large geographically diverse market footprint. The mix of Colorado renewable resources varies depending on the market as Colorado responds to complement the generation mix of the broader region.



There are potentially additional economic benefits that were not modeled in the Siemens PTI study. For instance, the Siemens study did not model the potential benefit of more coordinated ancillary services. As noted in the initial comments from Holy Cross provided on November 15, 2019 in Proceeding No. 19M-0495E:

> [t]here is no competitive mechanism in Colorado today for other utilities, independent power producers or demand response resources to provide these so-called ancillary service capabilities. This results in higher costs for Colorado consumers and preserves market power for large incumbent utilities, which is not in the public interest. In contrast, modern regional markets allow the competitive procurement of ancillary services to balance generation with load and to provide emergency backup supply.
>
> Holy Cross Comments at p. 4.

The Siemens analysis also does not include an optimized expansion of the transmission infrastructure. The Siemens study did look at the impact of certain transmission upgrades. The transmission sensitivity analyses suggest that more regional connectivity could drive an additional approximately 1 percent in total system revenue requirement reduction, depending on the cost of the transmission upgrade.

The cost of administering the OWM was not included in the Siemens study. These costs were not included because the analysis contemplated RTO markets that either do not exist

[33] Siemens Study Exhibits 36, 74, 115, and 155.

today (in the case of the WECC-based market) or are in the early stages of development (in the case of the SPP-West market option). However, it is worth considering the not insignificant cost of market administration based on today's existing RTOs.

Table 3: *Costs of RTO Administration*[34]

	2019 Peak Load (MW)	2020 Cost ($Millions)	Cost/MW
NY-ISO	32,392	$168	$ 5,186
SPP	50,662	$174	$ 3,435
CAISO	46,526	$187	$ 4,019
ISO-NE	22,224	$201	$ 9,044
ERCOT	74,820	$268	$ 3,582
PJM	151,358	$296	$ 1,956
MISO	125,000	$368	$ 2,944
Colorado Estimates			
CO in SPP	10,000	$34	$ 3,435
CO in CAISO	10,000	$40	$ 4,019

Based on estimated administrative costs per megawatt, the cost to Colorado for participating in a CAISO or SPP administered market could be in the range of $34 to $40 million annually. This is in comparison to the potential for approximately $220 million/ year in system benefits for these RTO market options.

The DOE-funded market study estimated the costs of RTO market administration to be in the range of $0.33/MWh to $0.90/MWh. This translates to a range of $18 to $50 million annually for Colorado's retail sales of 56 million MWh. This range for fees is roughly consistent with **Table 3**.

As noted above, market participation brings other benefits as well. Tri-State observed in its comments filed on July 16, 2021, in response to Decision No. C21-0348-I which was issued in Proceeding No. 19M-0495E on June 14, 2021 that:

> With the high penetration of renewables required to meet Colorado's GHG emission reduction goals and the resulting weather-dependent generation, it will be extremely difficult to maintain reliability within a smaller (single state) geographic footprint. The broader footp=54hjunt of an RTO like SPP provides the needed generation alternatives to "keep the lights on" during severe weather events. The cost of significant load-shedding is large and, although that cost is not easy to estimate, it is an impact that must be considered in the overall evaluation.
>
> Tri-State Comments at pp. 11-12.

Joint Commenters Western Resource Advocates (WRA), Western Grid Group (WGG), and Natural Resources Defense Council (NRDC) state:

[34] Data from Presentation by PSCo to the PUC as part of a Commissioner's Information Meeting on January 28, 2021.

> By enabling automated, efficient and more coordinated utility operations, organized markets enhance reliability of the electric grid, reducing risks of reliability events, including load shedding. Generally speaking, RTOs offer more comprehensive market services and greater visibility into grid operations, meaning that these market constructs have the ability to enhance grid reliability even more than an EIM.[35]
>
> WRA/WGG/NRDC Comments at pp. 8

D. Day Ahead Market Potential

At the time that the CTCA legislation was passed, most of the market activity was focused on imbalance markets and full RTOs. However, since the passage of SB19-236, CAISO has re-engaged in the development of the EDAM and SPP has announced it is working to develop a product called MarketsPlus which would include both real-time balancing and day ahead services.

Because there is not a DA market operating in the West, or anywhere else in the country, the exact extent of the services provided by these market alternatives is not currently known.[36] For instance, if a DA market also included consolidation of BAAs and a joint transmission tariff, the market benefits would likely include long-term planning reserve margin sharing and result in reduced capacity expansion costs. Such a market services package could deliver much of the benefits associated with the RTO participation modeled in the Siemens PTI analysis. But the benefits of a DAM offering fewer of these services would likely be closer to the IM savings.

Based on the Siemens PTI modeling shown in **Figure 6** above, of the approximately $230 million in annual benefits from the RTO cases, approximately $50 million comes from the real-time imbalance service and another $50 million comes from day-ahead unit commitment and dispatch. It is reasonable to conclude that a DAM would deliver benefits in the range of $100 million/year (based on the lower end of service provision) to $230 million/year (based on the higher end of service provision).

The DOE-funded market alternatives analysis reflects a similar conclusion. The DA market modeled produced substantially more benefits than the stand-alone EIM (1.3 percent overall savings for the DAM versus 0.2 percent for the EIM) but not as much benefit as the RTO market (2.8 percent overall savings). The DOE modeling of the DAM assumed no joint tariff but approximately 50 percent of the capital investment savings relative to the RTO option.[37] In addition, the DOE-funded study estimated the administrative cost of a DA

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[35] Initial Comments of WRA, West Grid Group, and the Natural Resources Defense Council filed on November 15, 2019 in Proceeding No. 19M-0495E at p. 8.

[36] For instance, CAISO announced on November 10, 2021, the formal kick-off of the Extended Day-Ahead Market stakeholder process (http://www.caiso.com/Documents/California-ISO-Formally-Kicks-off-Extended-Day-Ahead-Market-Design-Stakeholder-Process.pdf)

[37] While these savings appear lower than those calculated by the Siemens study, the overall conclusions regarding the role of market integration level and geographic scope remain the same.

market to be in the range of \$0.15/MWh to \$0.45/MWh, or between \$8 and \$25 million for the State of Colorado.

The Siemens PTI analysis did include a combined JTPP scenario which would function similar to a DA market. This scenario included real-time balancing and day-ahead unit commitment and dispatch but did not include any reserve margin sharing benefits. In addition, the scenario covered a substantially smaller geographic footprint, covering most of the states of Colorado and Wyoming. Even with the provision of day-ahead market services and a joint transmission tariff across the market footprint, the estimated benefits were roughly equivalent to the stand-alone EIM benefits associated with the larger market footprints – roughly 1 percent of total system revenue requirement.

E. Other Regional Market Modeling Efforts

The Commission's review of other leading quantitative studies in the West of the benefits of enhanced regional coordination tends to find similar general order-of -magnitude cost savings and efficiencies.

i. DOE-Funded / State-led Market Study

In addition to the Commission's modeling efforts, the US Department of Energy (DOE) funded a study, led by state energy offices, analyzing options for coordinated wholesale markets in the West. This study was published in September of 2021 and provides additional modeling and perspective on Western market options and activities. Commission Staff and the Colorado Energy Office participated in this study entitled "*The State-Led Market Study -- Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies*." The final technical report and accompanying Market and Regulatory Review scorecard were filed in the PUC's proceeding in September 2021.[38]

Similar to the Siemens study, the State-Led study evaluated real-time (imbalance) and RTO markets (and in addition, a Day-Ahead market modeled after CAISO's EDAM proposal) across several western footprints. Unlike the Siemens study, it only examined two time periods (2020 and 2030), did not assume achievement of Colorado's carbon reduction goals and used a different methodology to examine capacity (investment) savings.

The State-Led study produced similar overall findings to the Commission's Siemens analysis concluding that all organized markets studied would produce savings compared to the status quo, but the greater the level of market integration and services provided and

Also, the DOE-funded study examined a shorter timeframe and did not assume Colorado achieved the 80 percent by 2030 CO2 reduction target. Both of those factors could reduce the resulting savings produced by the study in comparison to the Siemens analysis.

[38] The State-Led study evaluated real-time (imbalance) and RTO markets (and in addition, a Day-Ahead market modeled after CAISO's EDAM proposal) across several western footprints. However, the study only examined two time periods (2020 and 2030), did not assume achievement of Colorado's carbon reduction goals and used a different methodology to examine capacity savings.

the larger the market footprint, the greater the savings. Advisors estimated the modeled savings for the State of Colorado to be approximately 0.2% for the IM, 1.3% for the EDAM, and 3% for the RTO cases.

Table 4: *DOE/State-Led Study Savings Results for Colorado*

Case	Annual Savings ($mil)	% Savings	Notes
2020 WECC-wide IM	13	0.2%	
2030 WECC-wide Day Ahead	76	1.3%	Using top end of capacity savings range
2030 WECC-wide RTO	160	2.8%	
2030 2 Market A RTO	167	2.9%	WECC divided into 2 markets: 1. CAISO and 2. Rest of WECC
2030 2 Market B RTO	10	0.2%	WECC divided into 2 markets: 1. MWTG and 2. Rest of WECC

ii. Other Studies

A number of other noteworthy recent studies have quantified the benefits of market participation and are included as part of the record in the Commission's Markets investigation.

1. CAISO EIM Quarterly Market Benefits Reports estimate the benefits, by entity, of EIM participation:
    a. As mentioned above, the most recent EIM quarterly report (Q3 of 2021) estimates cumulative gross benefits since November 2014 of $1.72 billion
    b. Third quarter of 2021 benefits over $300 Million with a 9,862 metric ton reduction in CO2 as a result of reduced renewable curtailments.
2. Vibrant Clean Energy's (VCE) study on behalf of Holy Cross Energy (HCE) and the Intermountain Rural Electric Association (IREA now known as CORE). Studied energy imbalance market participation options for Colorado.[39]
    a. Allowed optimized expansion of both generation and transmission infrastructure
    b. Did not assume compliance with Colorado's 80x30 CO2 emission reduction goals
    c. Evaluated EIM, EIS, and split participation scenarios

[39] https://www.vibrantcleanenergy.com/wp-content/uploads/2020/10/CO-EIM-Options-Report.pdf. Filed in this proceeding on January 26, 2021.

   d. Concluded that EIM participation could result in \$0.8 to \$1.2 Billion in cumulative savings relative to the reference case
   e. Concluded that the benefits of EIM participation are substantial and greater when all Colorado entities participate in the same EIM
3. Brattle Group study "Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study" assessing EIM participation options.[40]
   a. Analyzed a single year, 2024, for EIM participation
   b. Evaluated EIM, EIS, and split participation scenarios
   c. Estimated EIM participation benefits for the JDA members ranging from \$2 to \$17 million per year in production cost savings
4. Brattle Group's study on behalf of Southwest Power Pool studying benefits of the Western Energy Imbalance Service and RTO Participation. [41]
   a. Evaluated the Status Quo, the WEIS, and an expansion of the SPP RTO to encompass the WEIS footprint for a single year, 2028.
   b. Estimated \$9 million/year in WEIS benefits for Colorado entities (WACM BAA)
   c. Extension of the SPP RTO to include the WEIS footprint increased the benefits to Colorado an additional \$25 million/year
5. MWTG Modeling Efforts

While the exact estimate of the benefits varies across the studies, they all generally confirm the Commission's Siemens study conclusions that participation in an organized market has the potential to deliver benefits to the State of Colorado through lower overall operational and investment costs and that these benefits increase with the level of market services included in the wholesale market structure.

[40] https://www.brattle.com/news-and-knowledge/publications/joint-dispatch-agreement-energy-imbalance-market-participation-benefits-study, January 14, 2020. Filed in this proceeding on January 28, 2020.

[41] https://www.brattle.com/news-and-knowledge/publications/western-energy-imbalance-service-and-spp-western-rto-participation-benefits. Filed in this proceeding on January 26, 2021.

IV. CONCERNS IDENTIFIED WITH ORGANIZED WHOLESALE MARKETS

Along with the benefits of greater coordination of resources come a host of other concerns and complications. The Commission has identified a number of concerns with RTOs that should be considered when a specific RTO opportunity is presented.

A. Governance

Today, Colorado utilities operate under a robust and mature regulatory framework. Colorado has a nationally recognized resource planning process for the evaluation and acquisition of new generating resources that includes review of transmission upgrades and interconnection. There are structures in place to review the prudence of utility operations, fuel expenditures, and other cost recovery based on actual utility costs. The Joint Dispatch Agreement covering the PSCo BAA functions as a smaller size imbalance market to optimize real-time energy for participating utilities. As part of the consideration of market participation, it is important to consider the impacts on these well-functioning systems of governance.

The development of rules and tariffs that guide a market's operations is shared among member utilities, stakeholders, boards of directors, specific market committees, and ultimately, FERC and the courts. For simple majority voting and sector voting, the number of votes held by entities representing the interests of Colorado could be few, or even none. While RTOs and ISOs have some structure to receive input from the states that member utilities operate in, the purpose of RTOs is not to address state concerns and implement state policy. RTO "directors owe a duty to the RTO and to its mission which… is not principally to shareholders and profits but is instead usually framed in terms of promoting market efficiency and social welfare." However, "RTOs are beholden to transmission owners as a practical matter… because the consent of these utilities gave rise to RTOs in the first place."[42]

i. SPP Governance

SPP's current approach to governance raises both short- and long-term concerns. In the near-term, the current governance of SPP's energy imbalance market (the WEIS) vests substantial voting rights in individual power marketing agencies and cooperatives, with little opportunity for regulators to meaningfully participate. This can create concerns for new utility entrants from Colorado.

More broadly, SPP's RTO governance structure allows for state participation through the Regional State Committee (RSC), which is composed of one state utility regulator from each state with regulatory jurisdiction over an SPP member.[43] The RSC determines the region's

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[42] https://www.rstreet.org/wp-content/uploads/2019/08/FINAL-RSTREET180.pdf

[43] SPP Bylaws Art. 7.2.

approach to resource adequacy, "whether transmission upgrades for remote resources will be included in the regional planning process and the role of transmission owners in proposed transmission upgrades in the regional planning process."[44]

SPP uses a formal stakeholder process but typically allows for protracted discussion and iterative analysis of proposals to build consensus among its members. To participate in many of SPP's market rule and tariff development processes, an entity must be an SPP member. The annual membership fees apply to NGOs and consumer advocates; currently, no NGOs or consumer advocates belong to SPP. [45] These high barriers to participation are far removed from the State's current robust stakeholder engagement culture.[46]

ii. CAISO Governance

CAISO may have even more serious governance concerns than SPP in terms of its long-term ability to lead an OWM in the West. Effective control of CAISO is vested in a board of directors and a stakeholder process that is effectively controlled by the State of California. Given this reality, the risk exists that CAISO could protect California's parochial interests at the expense of what is best for the region. Recent filings by CAISO surrounding a "wheel through" tariff, which was approved by FERC earlier in 2021,[47] appears to have significantly exacerbated and given substance to these concerns.[48]

iii. Governance Characteristics

Colorado stakeholders share concerns regarding the transparency and accessibility of RTO governance structures. For example, a recent white paper issued by public interest organizations participating in SPP's Member's Forum set forth minimum governance principles highlighting key areas where best practices can be implemented to enable

[44] SPP Bylaws Art. 7.2.

[45] Certain entities can request a waiver of the membership fee.

[46] As stated by Black Hills on page 3 of the Comments responsive to Decision No. C21-0348-I "The governance structures of the existing RTOs may not be flexible enough to ensure that western utilities and stakeholder issues and concerns are heard or resolved."

[47] http://www.caiso.com/Documents/Jun25-2021-OrderAcceptingTariffRevisionsSubjecttoFurtherCompliance-SummerReadiness-ER21-1790.pdf

[48] *See articles such as*: https://www.newsdata.com/california_energy_markets/bottom_lines/arizona-exploring-next-steps-after-ferc-approves-caiso-wheel-through-rules/article_0bb111d0-db84-11eb-a3c4-ffe4457e0ab1.html

and https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/052721-western-utilities-states-battle-california-over-summer-power-sharing-plan transparent and responsive governance.[49] The key principles for stakeholder processes set forth in the white paper include:

- Principle #1: Decision-making at all levels of the stakeholder process should be as transparent as possible.
- Principle #2: Membership must be reasonably available to all interested stakeholders, including public interest organizations.
- Principle #3: Minority positions must be recognized and actively considered throughout the stakeholder process.
- Principle #4: The Board of Directors must be diverse and independent and should actively consider the concerns of its membership, while not being beholden to market participants.
- Principle #5: State Utility Commissions and Public Interest Organizations should have a major role in RTO formation and once formed, the RTO's ongoing operations.

B. Resource Adequacy

Although organized markets can and do contribute to electric system reliability by providing a wide-area view and appropriate information sharing between the market operator and the reliability coordinator, recent events have provided reminders that RTOs are not immune from significant reliability concerns, particularly related to resource adequacy.[50] The most recent NERC Summer Reliability Assessment showed an elevated or high risk of insufficient operating reserves in several RTO regions, including CAISO, MISO, and ERCOT. In addition, SPP issued a Resource Alert in June 2021 "due to outages, high loads, and wind forecast uncertainty."[51]

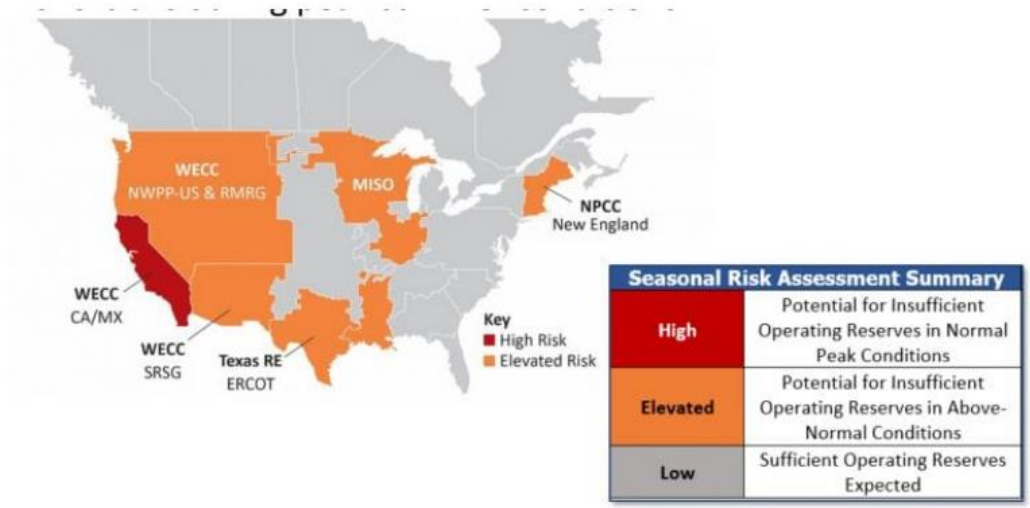
[49]https://3hzk7prqhr33icsww1y4geu6-wpengine.netdna-ssl.com/wp-content/uploads/2021/08/2021-06-30_PIO-Comments-SPP-RTO-West-Terms-and-Conditions_SPP.pdf

These governing principles were developed by Interwest Energy Alliance, Natural Resources Defense Council, Northwest Energy Coalition, Sierra Club, Sustainable FERC Project, Western Grid Group, and Western Resource Advocates.

[50] Winter Storm Uri resulted in long and widespread outages across the ERCOT RTO driven in large part to a lack of investment in winter weatherization. This is discussed further in the "Price Formation" section of this report. The CAISO has, for the last few summers, been experiencing extreme capacity shortages often resulting in rolling blackouts.

[51] As noted by Tri-State in its comments on page 6, in response to Decision No. C21-0348-I, the "Commission's oversight of Colorado resource planning – including with respect to Tri-State pursuant to the Commission's new Rule 3605 – will remain unchanged should Tri-State or other Colorad]o electric utilities participate in the SPP RTO."

Figure 8: *2021 NERC Summer Reliability Assessment*



Colorado today has a well-regarded regulated ERP process that has successfully addressed resource adequacy and portfolio optimization through robust competitive solicitations. These bidding processes have produced record low prices for wind and solar acquisitions. Public Service's 2017 All-Source Solicitation garnered bids for 238 individual projects representing over 58GW of capacity. Public Service's 2019 ERP Amendment designed to replace about 200MW of failed solar projects received bids for 68 individual projects representing 10 GW of capacity with a median solar price of $24/MWh and a medium solar-plus-storage price of $36/MWh. This success extends beyond just Public Service. In the 2019 ERP Amendment from Black Hills, the utility sought to acquire about 200 MW of renewable resource. The solicitation received 47 bids below the utility's average cost to serve, representing 5.6 GW of capacity.

In Colorado, the regulated resource planning process has resulted in demonstrably economic resource acquisition. A Utility Dive article from June of this year titled "Xcel's record-low-price procurement highlights benefits of all-source competitive solicitations" states "Xcel's [2017] ASCS returned a $0.017/kWh bid for wind, a $0.023/kWh bid for solar, and a $0.03/kWh bid for solar-plus-storage... These prices, compared to Colorado's average January 2021 residential electricity price of $0.126/kWh, have other utilities asking how they can use this procurement approach."[52] In considering the impact of Colorado utilities joining an organized wholesale market, the Commission should consider the beneficial processes we have today, such as the All Source Competitive Solicitation that efficiently flows the benefits of low-cost generation through to customers.

[52]https://www.utilitydive.com/news/xcels-record-low-price-procurement-highlights-benefits-of-all-source-compe/600240/

C. Price Formation

Comments from several stakeholders suggested that participation in an RTO should be considered essential to achieving Colorado's GHG reduction goals.[53] However, there have also been challenges to this view that question the suitability of current market operations to support these goals. For example, the Utility Consumer Advocate (UCA, formerly known as the Office of Consumer Counsel) provided a recent white paper by Tony Clark and Vincent Duane that calls out price formation as one area in which the current RTO model is "misaligned with public policies that seek to advance grid decarbonization."[54] The paper explains the issues as follows:

> Foundational to the challenge facing RTOs is the matter of price formation. Meaningful price signals, as expressed through locational marginal price (LMP), are central to the functioning of RTOs. Prices are the keys to the RTO kingdom. In theory and in practice, prices signal how generation investments should be made, when facilities should retire, and when transmission should be built. They are the primary tool by which grid operators ensure reliability, and they are increasingly important to interconnected distributed resources.
>
> The question becomes: what happens when price is no longer an effective tool for fulfilling the tasks that RTOs were created to complete? If an increasing portion of the grid is characterized by socialized fixed charges and generation such as wind and solar that neither set prices nor respond to price signals, the impact could be profound.

i. Locational Marginal Prices

As renewable generation begins to dominate in the generation of electricity, the portion of time when the locational marginal price is set by these resources will increase. Since the marginal cost of wind and solar generation is essentially zero, this will put downward pressure on overall wholesale electricity prices. This in turn, impacts the profitability of new generation resources. While ratepayers certainly benefit from lower prices, the price needs to be high enough to attract developers to bring on new generation resources to meet demand. This trend seems to be playing out in some markets across the country as demonstrated by **Figure 9** below. This figure demonstrated that the downward trend in prices over the last ten years has pushed the price below the price needed to invest in new gas generation.

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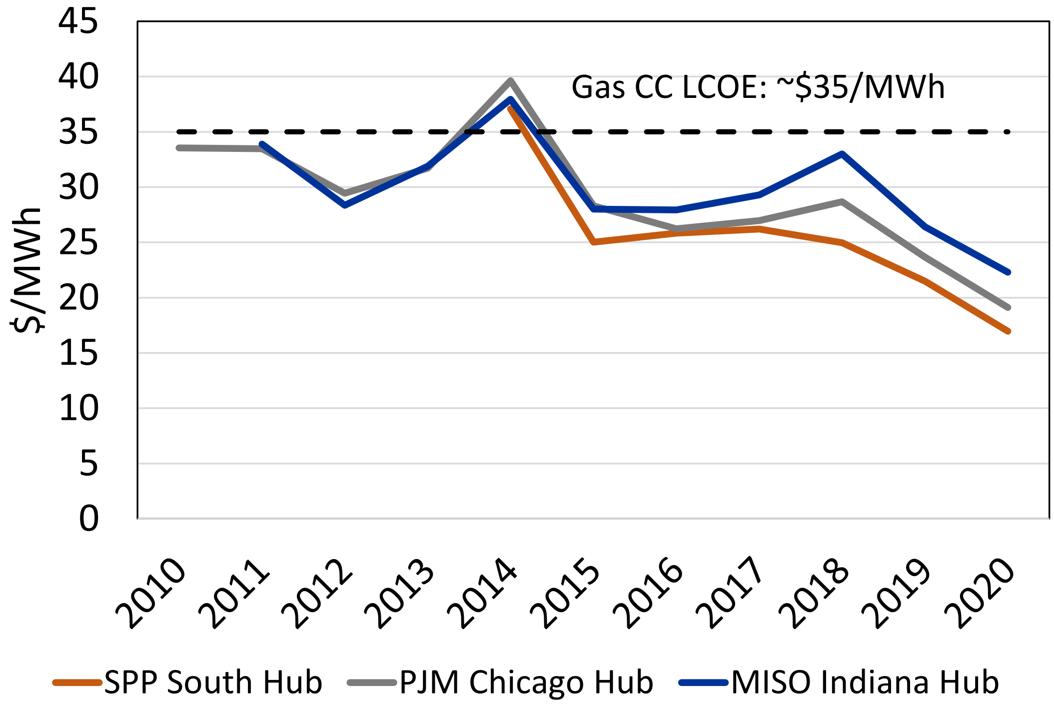
[53] Find examples. *E.g.,* WRA 2019 comments.

[54] Attachment 4 to The Colorado Office of Consumer Counsel's (now known as the Office of the Utility Consumer Advocate) Comments in Response to Decision No. C21-0348-I at p. 3 (emphasis added).

Figure 9: *Average Annual Real Time Price in SPP, PJM, and MISO*[55]



Even in an RTO, regulated generators still recover costs through regulated rates. But merchant generators rely on market prices to recover development costs. The downward pressure on wholesale electricity prices has the potential to discourage development of new generation, potentially contributing to resource adequacy concerns across the country. Different RTOs address the resource adequacy concerns that arise in different ways. SPP and MISO largely continue to leave resource planning up to constituent state regulators resulting in robust resource planning and few adequacy concerns. Other RTOs have taken different approaches with less success such as PJM's capacity market and ERCOT's lack of any resource adequacy requirement.

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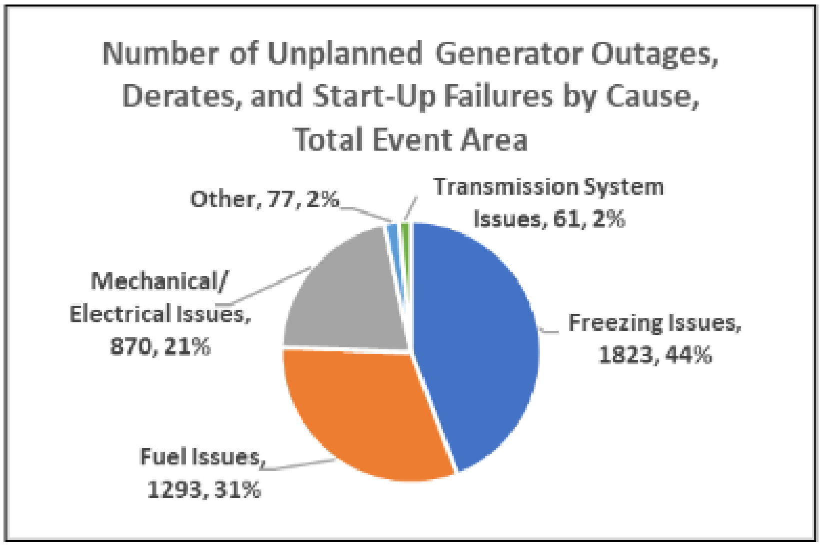
[55] S&P Global Market Intelligence, NREL Annual Technology Baseline

ii. Winter Storm Uri

The apparent lack of appropriate investment in the ERCOT electricity system is one variant of this concern. The market price signals in the years prior to the 2021 Winter Storm Uri extreme weather event were not high enough to justify investment in winter weatherization equipment. A recent FERC report "February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendation" found that "Generation Freezing Issues" were the largest single cause of generation outages.[56]

***Figure 10:** Causes of Outage in ERCOT During Winter Storm Uri*



The report concludes that "The electric and natural gas industries need to strengthen their winterization and cold weather preparedness and coordination to prevent a recurrence of the unprecedented February 2021 power outages to millions of people during the February 2021 freeze in Texas and the Midwest." The market price signals in the ERCOT RTO were not strong enough to provide an incentive for the appropriate level of reliability investment. Now, state and federal regulatory oversight is needed to establish more robust reliability standards in response.

These concerns are not unique to RTOs but they are something of a cautionary tale. RTO benefits are driven by the efficient market dispatch that results for the market price signals. But those price signals may not be sufficient, particularly in a deep renewable future, to incent the investments needed to maintain a reliable system with the proper oversight and involvement of regulatory bodies.

[56] https://www.ferc.gov/february-2021-cold-weather-grid-operations-preliminary-findings-and-recommendations

D. Interconnection Queue Management

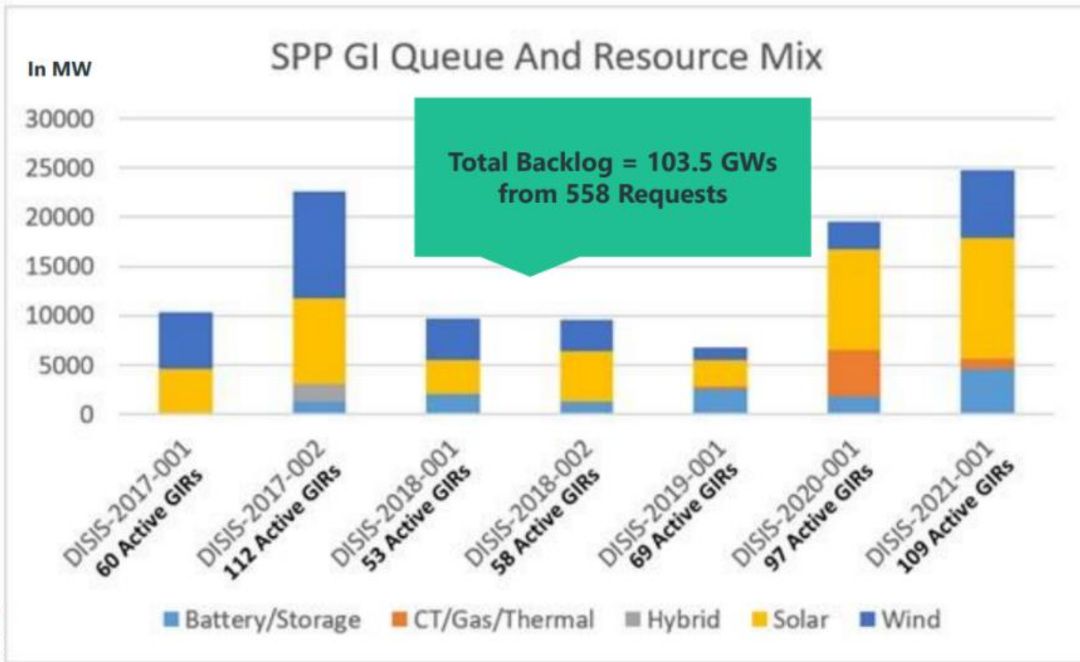
Currently in Colorado, interconnection access is evaluated as part of the resource planning process in order to ensure that beneficial renewable and other low-cost, competitively acquired generation can be developed to the benefit of ratepayers. Both Public Service and Tri-State recently received FERC approval to implement large generator interconnection queue modifications to implement cluster interconnection studies and to ensure that projects approved through utility planning processes can get priority access to interconnection resources.

RTOs, on the other hand, are struggling with the management of interconnection processes. As summarized in a recent article from Americans for a Clean Energy Grid "[t]he current system for planning and paying for expansion of the transmission grid is so unworkable and inefficient it is creating a huge backlog of unbuilt energy projects. At the end of 2019, 734 gigawatts of proposed generation were waiting in interconnection queues nationwide."[57] The article further concludes that "[a]lthough Regional Transmission Organizations (RTOs) and the Federal Energy Regulatory Commission (FERC) have undertaken worthwhile attempts to alleviate interconnection backlogs, the interconnection queues remain costly, lengthy, and unpredictable."

In SPP alone, the interconnection queue backlog amounts to over 100GW of primarily wind and solar generation projects – more than twice the size of all of SPP. While SPP has set up a task force to address the "extreme amounts" of new generation waiting to interconnect, it is not clear when and how queue reforms will address the current backlog or establish a well-functioning queue for new projects. SPP has indicated that an SPP-West RTO would establish a new interconnection queue in order to avoid the current backlog in SPP East. However, it seems only logical that an RTO adopting the same processes would soon be facing a similar problem. It is not clear why Colorado would trade its current well-functioning interconnection processes for a system that has created such inefficient and unequitable access.

[57] Disconnected: The Need for a New Generator Interconnection Policy, by American for a Clean Energy Gird, January 2021 (https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf).

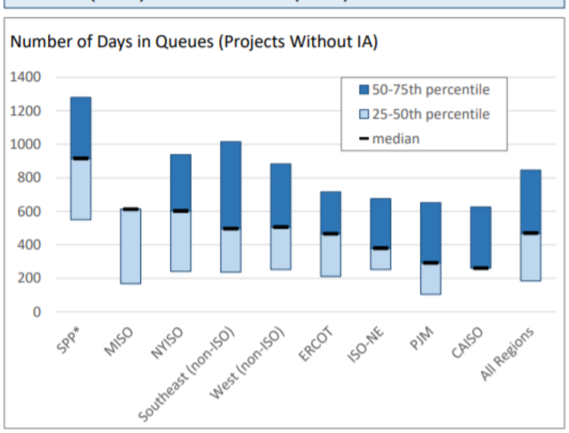
Figure 11: SPP Interconnection Queue



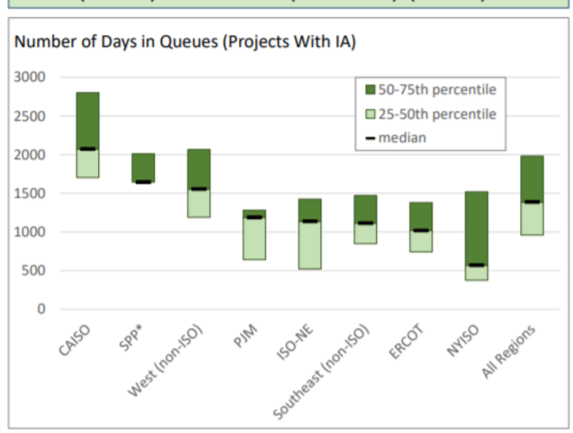
This concern is not unique to SPP. **Figure 12Figure 12** below shows the substantial interconnection queues for many of the nation's RTOs. It is currently taking years for important renewable investment to make it through the RTO interconnection process.

Figure 12: RTO Interconnection Access Queue Times

Among projects *without* signed IAs, those in SPP (median = 915 days) tend to have spent the longest time in the queues, followed by MISO (612) and NYISO (602).



Among projects *with* signed IAs, those in CAISO (median = 2,072 days) tend to have spent the longest time in queues, followed by SPP (1,645), and West (non-ISO) (1,555).



Similar to the resource planning and adequacy issues, the Commission should consider ways to retain the beneficial interconnection process we have today that allocates the scarce interconnection resource to the benefit for retail customers.

E. Transmission Cost Allocation

i. Existing Transmission Assets

When a transmission-owning utility places its existing facilities under a joint tariff, these facilities are included in a zone ("pricing zone") that contributes to the zone's revenue requirement. The pricing zone design of the joint tariff can directly impact customer transmission rates. The de-pancaking of the system can create new cost implications depending on the zonal rate structure deployed within the joint tariff.[58] As demonstrated by the MWTG negotiations, the issue of establishing transmission zones can involve significant cost shifting amongst utilities for existing transmission assets, potentially requiring mitigation with impacts to ultimate transmission rates.

ii. New Transmission Assets

Depending on the cost allocation policies for new transmission established by the RTO, an individual utility can be required to pay transmission costs for projects in other areas of the footprint. This occurs when costs of individual utility projects are assigned to all transmission zones in the RTO. Allocation of transmission costs, particularly for regional transmission projects, can be contentious because benefits of transmission accrue unevenly. A line, for example, transmitting electricity from generation in one state, across another state, and serving load in a third state clearly benefits the state with load served, also benefits the state where generation is located, but provides no obvious benefit to the state crossed.

Transmission cost allocation is intertwined with transmission planning. FERC Order 1000 therefore included reform of cost allocation, noting that it is necessary for each public utility transmission provider, whether an ISO/RTO or non-ISO/RTO, to include in its OATT, a method(s) for allocating costs of new regional and interregional transmission in a plan. FERC emphasized that *all* benefits of new transmission facilities need to be accounted for in order to fairly allocate costs, while acknowledging that determination of benefits (and beneficiaries) is difficult.

These issues can only be properly addressed in the context of a specific RTO market with specific transmission assets and cost allocation policies. In addition, the outcome of the FERC ANOPR will have important implications for RTO transmission planning and cost allocation that will need to be understood.

[58] *See* the Comments of Public Service Company of Colorado, pp. 16-19, filed on July 16, 2021 in Proceeding No. 19M-0495E.

F. GHG Emissions Tracking and Accounting

While RTOs do not create emission tracking concerns, the increased intra-state trading that accompanies market participation increases the need for tracking and accounting. As explained in the Siemens PTI report:

> GHG leakage occurs when production (e.g., output of electricity) that creates GHG shifts away from states with relatively strict GHG reduction targets and toward states with less strict targets, as utilities in the latter change operations (including imports) to meet state GHG goals. Leakage could occur in the electricity industry if energy imported into a state is not required to identify and account for GHG emissions.

As observed by the Sierra Club in comments in response to Commission Decision No. C21-0348-I "[i]f Colorado utilities join RTOs with utilities and states that have climate policies that are not aligned with Colorado's climate policies, there are significant risks to Colorado's ability to achieve its climate goals."

There are two general ways market participants count emissions from market-based electricity transactions today: 1) A pooled average approach where emission rates are equated to the aggregated average from a particular region, and 2) A marginal or incremental approach where emissions rates are based on the particular resource from which the energy is supplied.

Intermingling these two approaches within a single jurisdiction, which often occurs due to data limitations, can lead to double-counting emissions reductions. This is because the emissions from individual transactions are embedded in the aggregated regional rates used in the pooled approach. For example, if an entity has a contract to purchase all the energy produced by a particular coal plant in a neighboring region, that entity will likely count any emissions using the rate for that particular plant. The entity may also purchase spot energy from the market operator in the neighboring region, and will likely use an aggregated average emissions rate when counting the emissions for that purchase. Partial double counting occurs in this example because the emissions from the previously referenced coal plant are embedded in the aggregated regional rate, even though all of that plant's emissions had already been accounted for through contracted purchases.

The current guidance from the Colorado Department of Health and Environment's (CDPHE) on market transactions does not preclude the previous example. It states that emissions should be based on actual purchases and sales where that data is available.[59] CDPHE further states that net aggregate data should be used when the specific transaction data is not available. CDPHE used aggregated Environmental Protection Agency EGrid regional emissions rates in their own calculations for baseline and projected emissions, presumably because this is the best available data.

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[59] CDPHE: "Clean Energy Plan Guidance" March, 2021. Available at the bottom of this web page: [Climate Change | Department of Public Health & Environment (colorado.gov)]

The aggregate versus incremental methodological issue historically has not been a major concern. Spot transactions have typically been a small portion of overall electric use and emissions targets have not been binding as they will be in future years. However, looking forward, entities will increasingly rely on regional markets to integrate high penetrations of renewable energy and control overall operational costs. Furthermore, emissions accounting procedures will be critical to determining compliance with GHG goals like 80 percent or 90 percent reduction targets.[60]

SPP does not currently track emissions or provide incremental emission rates for market purchases. The states in SPP's footprint in the Eastern Interconnect generally do not share Colorado's decarbonization goals and have not prioritized the establishment of GHG tracking. It is the market operators such as SPP that know which units on their system are marginal at any time and location and what units are contracted to specific purchasers. Development of a robust market-based GHG accounting system will be critical to verification of Colorado emission reduction goals when utilities participate in an organized market.

CAISO is already providing incremental emissions rates for their transactions occurring within the State of California.[61] This is done to determine a GHG adder cost and to apply border adjustments on electricity imports to comply with their state environmental policy. Given the climate targets of many of the EIM participating states, CAISO is looking to extend its ability to track incremental emissions from market purchases to the EIM (if they have not already done so).

[60] For example, this study demonstrates significant differences (*i.e.,* ~20 percent) in calculated emissions between using average pooled rates versus marginal rates for the same system: Marginal Emissions Factors for Electricity Generation in the Midcontinent ISO | Environmental Science & Technology (acs.org)

[61]https://www.westerneim.com/Documents/GreenhouseGasEmissionsTrackingMethodology.pdf

V. CONCLUSIONS/NEXT STEPS

While RTOs have the potential to deliver substantial benefits, they raise a host of concerns. These concerns extend to the most developed RTO option for Colorado today, SPP. In the short-term, it is appropriate to continue to explore market formation in the West and explore how utilities and RTOs may address the concerns discussed above. The Commission has found that *generally*, and based on the two-year long investigation, market participation is in the public interest, but this determination does not apply to participation in a *specific* market at this time.[62]

A. Market Conclusions

The Commission recognizes that participation in markets generally, and particularly RTOs, have the potential to provide customers with significant value through operating cost and infrastructure investment savings.

Significant progress has already occurred in the West. The CAISO EIM has consolidated and optimized real-time dispatch across 84 percent of the load in the West and created an estimated $1.72 billion in benefits over the past ten years.[63] CAISO has also begun to implement flow-based transmission approaches. More recently, the SPP has begun similar reforms, resulting in similar, if significantly smaller, benefits in the eastern side of the grid through its WEIS.

In this environment and given the alternatives likely to be available to Colorado transmission utilities, the Commission carefully quantified the potential benefits of markets for lowering the capital and operating cost of the generation system in ways that allow for the enhanced integration of low-cost clean energy resources. The Commission also considered the possible negative impacts associated with shifting state control over core generation, interconnection, and transmission decision-making, which have generally worked well in Colorado, to regional approaches that may currently be ill-defined or even dysfunctional.

The Commission's quantitative analysis concluded that markets have the potential to deliver substantial economic benefits through reduced operation and investment costs. The report estimates that EIMs could deliver on the order of $50 million in annual savings to Colorado (approximately 1 percent of a total annual Colorado electric revenue requirement of $6 billion). A full RTO participation could deliver approximately $230 million annually or 4 to 5 percent of the total annual revenue requirement. A DA market construct, similar to a regional power pool, could deliver savings somewhere between these two options, depending on the exact market services included.

These kinds of savings were generally found to exist independent of whether Colorado looked west to the CAISO, east to the SPP, or created something new in the middle working with neighboring utilities. As such, the quantitative study concluded that the key to

[62] Decision No. C21-0755, issued December 1, 2021.

[63] https://www.westerneim.com/Documents/ISO-EIM-Benefits-Report-Q3-2021.pdf

obtaining these benefits was effectively participating in a broader market footprint, but it didn't matter so much which one.

However, the Commission is concerned with the effects that market participation would have on the State's robust resource planning and interconnection queue processes and the PUC's authority over such issues as resource adequacy, emissions tracking and transmission cost allocation, and planning. As reflected in the Comments of the Colorado Energy Consumers filed on July 16, 2021 in response to Commission Decision No. C21-0348-I "[m]ere potential to achieve benefits is not enough; particularly where, as here, Colorado already enjoys a robust resource planning process and has a Commission that is laudably committed to matching such exemplary resource planning with an equally robust and efficient transmission planning process."[64]

Many of the concerns raised by RTO participation are specific to the individual RTO considered. Administrative fees vary by RTO and with the total size of the RTO footprint. Transmission interconnection queue management varies, as do emission tracking processes. Some RTOs, such as SPP and MISO, leave resource planning largely to the states while others, such as CAISO and PJM, have market features with potentially profound implications for state resource adequacy and planning processes. Additionally, we recognize that currently Colorado utilities have just one RTO option – SPP. The Commission observes that SPP's interconnection queue management processes seem to inhibit efficient allocation of the scarce transmission resources and that its governance models afford too much influence to a small number of entities through the Senate-style governance structure.

The Commission acknowledges and appreciates the positive step forward represented by the formation of the WMEG. However, this group is still in the early stages of formation. It is not clear if and how the WMEG will address the substantive concerns raised through the Commission's investigation.

Imbalance market participation, and potentially DA market participation, generally avoid many of the concerns raised by the more integrated services of an RTO. EIMs and DAMs do not substantively impact resource planning, interconnection queue processes or transmission cost allocation. In addition, these markets have lower administrative costs and exits fees, making the decision to join an imbalance reasonably reversible.

Therefore, imbalance markets may provide a beneficial first step towards greater market integration. These markets provide benefits in terms of renewable integration as well as operational efficiency. Currently, EIMs are also exploring DAM options that may form a middle ground, providing the more substantial economic benefits of an RTO without jeopardizing many of the positive characteristics of Colorado's current market structure and state-level influence.

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[64] Colorado Energy Consumer's Response at p. 1 (emphasis omitted).

B. Next Steps

Given the wide range of potential public interest considerations and uncertainties associated with evolving regional market opportunities in the West, this Commission intends to increase its efforts to coordinate with other regulators in the West. The dispersed nature of the problem, the lack of an obvious solution, and the diversity of discussions in the West could all benefit through expanded leadership from state regulators.

i. Near-term Market Participation

Between now and the 2030 statutory requirement in SB21-072 to join an OWM, along with working to address the concerns raised by the Commission, utilities should be exploring potential market options. Alternatives such as the EIM or DAM may deliver fewer, but still substantial benefits, raise less concerns, and would allow utilities to build market experience and expertise. Imbalance markets provide the least benefits but also the fewest entanglements as the EIM is limited to intra-hour balancing. The DA market construct has the potential to provide substantially more benefits but is still in the early stages of formation, so the exact benefits and tradeoffs are less clear.

The DAM concept is promising. The DAM concepts currently being developed in the West – by both CAISO and SPP – likely will include day ahead unit commitment, real-time balancing, optimization of ancillary services, and potentially planning and operating reserve margin sharing. These market services lead to enhanced system reliability and renewable integration in ways that are similar to a full RTO. At the same time, the DAM construct maintains existing planning and interconnection processes at the state level, in ways that limit governance concerns and avoids issues regarding transmission cost allocation.

This Commission welcomes Colorado utilities' participation in various processes designed to improve the status quo and enhance regional coordination in the West such as the WRAP, Western Market Exploratory Group (Western MEG), and the FERC ANOPR process. Collectively, these processes have the potential to improve resource adequacy, consolidate western balancing authorities, start de-pancaking transmission rates, shift to flow-based transmission approaches, and improve interconnect queue management and transmission cost allocation processes. Although the exact order in which to address each issue is not obvious, progress needs to occur along multiple fronts in order to obtain the benefits of enhanced regional coordination.

Under these circumstances, a reasonable near-term course for Colorado's transmission utilities may be to participate in an EIM to resolve intra-state dispatch issues and to capture the enhanced near-term coordination benefits but preserve the flexibility to adjust as regional market opportunities in the West evolve (*e.g.,* by limiting upfront costs, negotiating reasonable exit fees, etc.). This approach can enable Colorado's utilities to meaningfully continue discussions with other western stakeholders to evaluate how competing DAM and OWM structures can provide substantial additional benefit to Colorado over time, while also contributing to western efforts to improve the status quo and address existing concerns with the leading alternatives to OWM.

ii. Commission Rulemaking

Colorado's utilities are already joining energy imbalance markets and are contemplating participation in DA Markets and RTOs/ISOs.

As part of this effort to provide leadership in a rapidly evolving regulatory and market environment, this Commission intends to open a rulemaking proceeding to ensure that customers and the public interest are protected during the transition to a full OWM that may ultimately shift state control over key decisions to regional processes. The Commission believes that it is necessary to clarify the Commission's role in overseeing market participation, and utilities' obligations to update and inform the Commission, well in advance of SB21-072's 2030 deadline. This rulemaking will also further investigate regional market issues and make sure that different Colorado electric utilities are treated in a way that acknowledges the utility's situation-specific circumstances.

As stated in Decision No. C21-0755, the Commission believes that a rulemaking is a reasonable first stop to begin the implementation of SB21-072 and to continue addressing the issue of regional markets. Stakeholders have also suggested this path. As observed in the comments of Interwest Energy Alliance on July 16, 2021:

> the Commission can also open a rulemaking to guide decision-making in a transparent way related to governance, resource adequacy, maximizing efficient use and expansion of the transmission system (while mitigating if not eliminating seams), and supporting operational mechanisms consistent with Colorado public policy, including tracking greenhouse gas emissions and addressing concerns related to self-scheduling which may interfere with these goals.[65]

The Commission intends that the rulemaking address filing requirements for a utility to join a market, requirements for applicants to address the Commission's concerns with market participation, reporting expectations, and rules to implement portions of SB21-072 such as the process for a utility to receive a waiver of the statute's requirement to join an OWM.

Overall, the Commission hopes that enhanced regional coordination and participation in wholesale markets helps to accelerate the clean energy transition in Colorado and more broadly in a way that benefits all customers and maintains a safe and reliable electric system.

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[65] Interwest Energy Alliance Comments at p. 7.

PARTICIPATING STAKEHOLDERS

The Commission would like to thank all of the parties that provided comments or participated in the public hearing or at a Commissioners' Information Meeting. This is a very important and very complicated matter and we truly appreciate all of the thoughtful and informative comments we received. While this report does not include a comprehensive overview of all comments received, the entire body of information was considered by the Commission to inform this report.

- Advanced Energy Buyers Group
- Advanced Energy Economy Institute
- American Association of Retired Persons
- Black Hills Colorado Electric, LLC
- California Independent System Operator
- Climax Molybdenum Company
- Colorado Energy Consumers Group
- Colorado Energy Office
- Colorado Independent Energy Association
- Colorado Rural Electric Association
- Colorado Springs Utilities
- CORE Electric Co-operative (formerly known as Intermountain Rural Electric Association)
- Guzman Energy, LLC
- Holy Cross Electric Association, Inc.
- Institute for Policy Integrity at New York University School of Law
- Interwest Energy Alliance
- Larry Milosevich
- LSP Transmission Holdings, LLC
- Office of the Utility Consumer Advocate (formerly known as the Office of Consumer Counsel)
- Platte River Power Authority
- Poudre Valley Rural Electric Association
- Public Service Company of Colorado
- Sierra Club Environmental Law
- Southwest Power Pool
- Sustainable FERC Project
- Tri-State Generation and Transmission Association, Inc.
- Wal-Mart Stores, Inc. and Sam's West, Inc.
- Western Resource Advocates, Western Grid Group, and Natural Resources Defense Council

LIST OF ACRONYMS

Acronym	Definition
ANOPR	Advanced Notice of Proposed Rulemaking
ASCS	All-Source Competitive Solicitation
BAA	Balancing Authority Area
CAISO	California Independent System Operator
CDPHE	Colorado Department of Public Health and Environment
CEO	Colorado Energy Office
CEP	Clean Energy Plan
CSU	Colorado Springs Utilities
CTCA	Colorado Transmission Coordination Act
DAM	Day Ahead Market
DOE	US Department of Energy
EDAM	Extended Day Ahead Market
EIM	Energy Imbalance Market
ERCOT	Electric Reliability Council of Texas
ERP	Electric Resource Plan
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HCE	Holy Cross Energy
IREA	Intermountain Rural Electric Association (also known as CORE Electric Cooperative)
ISO	Independent System Operator
JDA	Joint Dispatch Agreement
JT	Joint Tariff
JTPP	Joint Tariff Power Pool (combined market)
LMP	Locational Marginal Price
OWM	Organized Wholesale Market
MISO	Midcontinent Independent System Operator
MWTG	Mountain West Transmission Group
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Council
NGO	Non-Governmental Organization
NRDC	Natural Resource Defense Council
NWPP	Northwest Power Pool
PJM	Pennsylvania, New Jersey, Maryland RTO
PP	Power Pool
PRPA	Platte River Power Authority
PUC	Public Utilities Commission
PSCo	Public Service Company of Colorado
RSC	Regional State Committee
RT	Real-Time
RTO	Regional Transmission Organization
SPP	Southwest Power Pool

UCA	Office of the Utility Consumer Advocate
WACM	Western Area Colorado Missouri
WAUW	Western Area Upper Great Plains West
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market (CAISO administered EIM)
WEIS	Western Energy Imbalance Service (SPP administered EIM)
WMEG	Western Markets Exploratory Group
WRA	Western Resource Advocates
WRAP	Western Resource Adequacy Process

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- https://www.michigan.gov/documents/mpsc/Feb_18_Competative_Procurement_Presentation__716684_7.pdf
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- Recent CPUC ERP Proceedings:
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  Public Service Company ERP Amendment: Proceeding No. 19A-0530E
  Black Hills Colorado Electric ERP Amendment: Proceeding No. 19A-0660E
- https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx
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- http://www.caiso.com/Documents/California-ISO-Formally-Kicks-off-Extended-Day-Ahead-Market-Design-Stakeholder-Process.pdf
- https://www.ferc.gov/news-events/news/ferc-naruc-establish-joint-federal-state-task-force-electric-transmission
- https://www.ferc.gov/news-events/news/advance-notice-proposed-rulemaking-building-future-through-electric-regional
- https://www.utilitydive.com/news/the-3-key-challenges-to-expanding-the-wests-real-time-energy-market-to-day/578390/
- https://www.westerneim.com/Documents/GreenhouseGasEmissionsTrackingMethodology.pdf
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- https://elcon.org/wp-content/uploads/Coalition-Letter-Independent-Study-of-the-Cost-of-Electricity-July-2021.pdf
- https://www.westerneim.com/Documents/QualitativeAssessment-PotentialReliabilityBenefitsWesternEnergyImbalanceMarket.pdf

QUANTITATIVE STUDIES FILED IN PROCEEDING NO. 19M-0495E

The Commission's Investigatory Proceeding can be found at:
https://www.dora.state.co.us/pls/efi/EFI.homepage
Search for: Proceeding No. **19M-0495E**

Other quantitative studies reviewed as part of this investigation:

- Siemens PTI-CTCA Evaluation of Market Alternatives: https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_777256
- Staff Presentation from PUC Public Hearing, June 24, 2021: https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_777659
- Colorado Energy Office Final Roadmap Technical Report: https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search
- DOE State-led Market Report and Review: https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_781244
- Joint Dispatch Area Energy Imbalance Market Participation Benefits Study and Comparative Analysis (Brattle Group JDA Study): https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_762524
- Western Energy Imbalance Service and SPP Western RTO Participation Benefits (Brattle Group SPP Study): https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_772435
- Energy Imbalance Market Options for Colorado (Vibrant Clean Energy Study for Holy Cross Energy and IREA): https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_772435
- Reports from the Mountain West Transmission Group Investigation Proceeding No. 16I-0816E: https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_759353