The Proposed Day-Ahead Markets in the WECC

A COMPARATIVE ASSESSMENT OF EDAM AND MARKETS+ DESIGN FEATURES

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I. Introduction

This whitepaper reviews and compares several market design features of the Extended Day-Ahead Market (EDAM) and Markets+, the two day-ahead markets proposed in the Western Electricity Coordinating Council (WECC). Many stakeholders in the WECC have suggested that certain market design elements, available in one market but not the other, will have material impacts on market outcomes and customer costs. We aim to compare specific elements of the two market designs and, where possible, provide evidence that sheds light on where one market's design is more likely to improve customer outcomes than the other.

The list below itemizes the design features of EDAM and Markets+ that we assess in this whitepaper and summarizes our key takeaways.

- **Flow-Based vs. Contract Path-Based Optimization.** Based on their tariff language, EDAM and Markets+ will both conduct: (1) flow-based optimization to fully utilize the transmission provided to their markets, while also (2) respecting the rights donated to the market by their members by imposing contract path-based constraints on their market clearing optimizations. Evidence from regional power markets in the eastern U.S. demonstrates the consequences when a market fails to respect contract path limitations in its market clearing optimization, and previous actions taken by the FERC illustrate that the Commission would likely force market operators to impose constraints in their optimizations to respect contract path constraints where necessary to limit adverse impacts on neighboring systems. There is no evidence in the EDAM and Markets+ tariff language, or from experience in other jurisdictions, to suggest one of the two day-ahead markets will be less inhibited by contract path-based constraints than the other, implying that market outcomes are unlikely to materially differ between the two markets due to contract-path constraints. If entities in the WECC are concerned about contract-path limitations reducing customer benefits in the market, the best solution would be to join a market where they are well-interconnected with other market members.
- **Fast Start Pricing.** The market clearing engine used for Markets+ includes fast start pricing (FSP) while the California Independent System Operator's (CAISO's) market clearing engine

(used for EDAM) currently does not.[1] Some stakeholders in the WECC have provided analysis suggesting that FSP has a large impact on market prices and the associated revenue collected by fast start generators in the market. However, detailed analyses conducted by the independent market monitors of the Midcontinent Independent System Operator (MISO), the Southwest Power Pool (SPP), and the Independent System Operator of New England (ISO-NE) all conclude that FSP has a *de minimus* impact on market prices. Based on that evidence, we conclude that FSP, or the lack of FSP, will not have a material impact on customer outcomes for Markets+ or EDAM members. This is particularly true for the vertically integrated utilities in the WECC that typically own or control enough generation assets to serve their own load.

- **Look Ahead and Optimized Real-Time Commitment.** The market clearing engine used by CAISO for the Western Energy Imbalance Market (WEIM) includes a four-hour look ahead period that enables it to optimize real-time unit commitment (RTUC) decisions for generation resources in the market that can cycle on and off in four hours across the entire market footprint. The market clearing engine used by SPP for the Western Energy Imbalance Service (WEIS) does not rely upon a similar look ahead period and does not perform real-time unit commitment, nor does the Markets+ tariff indicate that this will change with the implementation of the new market. These additional features of the WEIM optimization will allow it to find lower-cost and more operationally responsive solutions relative to the Markets+ real-time clearing that will not perform unit commitment and relies on manual real-time unit commitment decisions. While the look ahead feature provides an advantage of the WEIM over the real-time optimization of Markets+, it does not affect day-ahead market operations, where both EDAM and Markets+ optimize unit commitment and day-ahead dispatch.
- **Regional Economic Procurement of Imbalance and Flexibility Reserves.** In both EDAM and Markets+, members will be able to hold fewer load-following reserves due to the increased regional diversity in renewable generation and load. The magnitude of that benefit will depend on the size and geographic reach of the market footprint and the amount of diversity in renewable generation and load among market participants. The market with the largest footprint and greatest diversity of load and renewable generation resources will be able to deliver the largest diversity benefit and related cost savings to customers. The two markets will procure (the reduced quantities of) load-following reserves on a market-wide

[1] The CAISO market clearing engine does allow for block-loaded resources to set prices, which is a limited form of FSP applicable to that type of resource. The CAISO also procures Flexibility Ramp Product that compensates flexible resources, including resources with fast start capabilities. *See* California Independent System Operator, *Open Access Transmission Tariff*, Effective August 1, 2024, Section 44.

(rather than BAA-specific) basis. This allows the markets to procure the reserves from the most economic resources in the entire footprint (subject to deliverability limitations). Extending market-wide procurement to other reserve types in either EDAM or Markets+ would likely further reduce costs for customers.

- **Seams Optimization.** Markets+ will implement intertie trading at all points along its seam with neighboring markets and utilities while, under EDAM, intertie trading is only activated if market members elect to do so and at the CAISO BAA border. Intertie trading will allow for more economic transactions at the market seam that are then optimized within the market clearing engine, which will enable more efficient outcomes for market participants. The automatic inclusion of intertie trading at the Markets+ seam is likely to deliver benefits to market participants, and similar broad availability of intertie trading would be an improvement to the EDAM design.
- **GHG Pricing Mechanisms.** The Greenhouse Gas (GHG) pricing mechanism used in EDAM builds off the mechanism currently used in the WEIM, with added features to adapt it for day-ahead market operations. The EDAM approach benefits from ten years of operational experience and iterations with the CAISO, regulators, market participants, and stakeholders. The experience of the last ten years and our own forward-looking simulation analysis indicates that the WEIM/EDAM approach is effective at delivering customer savings while limiting leakage,[2] which could otherwise reduce the effectiveness of GHG regulations. Therefore, stakeholders in EDAM have more certainty that the GHG pricing mechanism will achieve efficient outcome while minimizing leakage. On the other hand, the Markets+ approach provides more options for market participants on how their resources are offered into GHG pricing states. As a result, market outcomes will be heavily dependent on the options chosen by Markets+ members and how regulators respond to outcomes in the market. Based on the description of its GHG options described in the tariff and stakeholder discussions, there will be few constraints to reduce leakage if most Markets+ members choose to make all their capacity available to the GHG pricing states. However, if most members choose to let the merit order determine which of their resources are available to

[2] Leakage describes the substitution of power from GHG-emitting resources located inside a jurisdiction that prices GHG emissions (GHG pricing states) with power from GHG-emitting resources located in jurisdictions that do not price GHG emissions. This occurs when the market clearing engine dispatches power from non-emitting resources outside a GHG pricing state to serve load inside a GHG pricing state (which results in less generation from emitting resources inside that GHG pricing state) but replaces the export of the non-emitting resource into the GHG pricing state with generation from an emitting resource outside GHG pricing states. While emissions inside the GHG pricing state are reduced, total market-wide emissions do not decrease; the market only reshuffles emitting and non-emitting resources. This phenomenon is also referred to as secondary dispatch, resource reshuffling, redispatch, among other terms. For consistency we refer to it as leakage throughout this whitepaper.

GHG pricing states, this will likely reduce leakage but may also eliminate many economic transactions in the market and result in a less efficient market outcome.

- **Congestion Revenue Allocation.** In both the EDAM and Markets+ the market operators will collect congestion revenues and allocate the revenues to market participants. However, the two markets have different approaches on how they will allocate those revenues to market participants. The EDAM approach will allocate congestion revenues back to the participating BAA and defer to each participant on how they will allocate the collected revenues to their transmission customers. The EDAM design will focus on both physical congestion within each BAA member's system (EDAM Congestion Revenues) and contact-path congestion between BAA members (EDAM Transfer Revenues). EDAM Transfer Revenues will be allocated to entities that have transmission rights between BAAs. The Markets+ approach will focus on each binding constraint in the market and allocate congestion revenues collected for that constraint to the rights holders on that constraint. This allocates congestion revenues directly to participating utilities' transmission customers. Neither approach is likely to affect the overall congestion revenues collected in the market, but specific market participants may be allocated a larger share of the congestion revenue under one approach compared to the other. For example, market participants that have a lot of long-term transmission rights on other participants systems may collect more congestion revenues under the Markets+ approach, while vertically integrated utilities with load obligations may find the EDAM approach to be more flexible in keeping their native customers whole if they are exposed to higher prices in the market due to congestion while also sharing congestion revenues with long-term transmission customers. If all EDAM members decide to suballocate congestion revenues to the holders of long-term transmission rights on constrained facilities, the two market designs will yield very similar outcomes.

Our review of the market design features in Markets+ and EDAM in this whitepaper provides evidence, where available, on the potential impact of each approach on market outcomes and customer saving due to these market design features. While some of the design differences between Markets+ and EDAM will impact market outcomes and overall market efficiency, they are unlikely to have a material effect on customer savings. Various analyses of customer benefits from market participation indicate that the largest drivers of customer savings will be the markets' the diversity of load and generation resources available in the markets, and the transmission connectivity between participating members, which all lead to increased economic trading and lower curtailments in the market.[3]

We hope this analysis of market design differences offers helpful takeaways for stakeholders in both markets on where the respective designs can be improved in the future, and help the region focus its efforts on developing the markets to enhance the overall efficiency and outcomes for customers.

3 Tsoukalis, et al., *Extended Day-Ahead Market Participation Benefits Study*, December 2023, pp. 26–31. Accessed at https://www.brattle.com/wp-content/uploads/2024/01/Extended-Day-Ahead-Market-Participation-Benefits-Study.pdf; Tsoukalis et al., *NV Energy Day-Ahead Market Benefits Studies, Comparative Benefits for NV Energy of Joining EDAM vs Markets+*, February 2024, p. 24. Accessed at https://www.brattle.com/wp-content/uploads/2024/03/NV-Energy-Day-Ahead-Market-Benefits-Studies.pdf; Energy and Environmental Economics (E3), *Western Markets Exploratory Group: Western Day-Ahead Market Production Cost Impact Study*, June 2023, pp. 23–24. Accessed at https://www.bpa.gov/learn-and-participate/projects/day-ahead-market;

II. Flow-Based vs. Contract Path-Based Optimization

Regional market clearing engines optimize unit commitment and economic dispatch decisions subject to transmission availability and other constraints. The term "flow-based optimization" is often used to indicate that a market clearing engine enforces only physical transmission constraints, while the term "contract path optimization" is often used to indicate that the market clearing engine accounts for both physical constraints and contractual transmission rights. Some stakeholders have suggested that Markets+ will rely solely on flow-based optimization, while the EDAM will continue the WEIM's practice of relying on both flow-based and contract path-based optimization. However, the complex nature of transmission rights in the WECC will require both markets to recognize contract path limitations based on how much transmission capacity is made available to the market. This is consistent with both markets' tariff language filed with the Federal Energy Regulatory Commission (FERC), which indicate that both markets plan to recognize contract-path transmission constraints where appropriate.

Pure flow-based optimization only enforces physical system constraints such as individual line ratings and interregional interface flow limits in the market clearing engine.[4] The resulting unit commitment and dispatch decisions use the transmission system's full physical transfer capabilities, producing the most efficient solution for delivering low-cost power to loads. Flow-based optimization is a central component to all regional power market clearing engines.[5] In some instances, market administrators impose additional contract path constraints to reflect the fact that only a portion of the regional grid's physical transmission capability is available to the market. Regional markets apply these constraints when non-members hold contractual transmission rights on assets that are also partially controlled by market members or when transactions executed within their market could cause parallel flows with unintended, costly, and potentially harmful impacts on neighboring systems.

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4 A flow-based market optimization aims to "match the scheduled transactions and actual power flows as closely as possible." H. Chao, S. Peck, S. Oren, and R. Wilson, *Flow-Based Transmission Rights and Congestion Management*. *The Electricity Journal*, October 2000, pp. 38–58. https://oren.ieor.berkeley.edu/pubs/flowbase.pdf.

5 "The AC Optimal Power Flow (ACOPF) is at the heart of Independent System Operator (ISO) power markets and vertically integrated utility dispatch." Federal Energy Regulatory Commission, *Optimal Power Flow and Formulation Papers,* June 2020. Accessed online at https://ferc.gov/industries-data/electric/power-sales-and-markets/increasing-efficiency-through-improved-software-0.

The tariff language filed with the FERC indicates that both the EDAM and Markets+ will primarily rely on flow-based optimization, like most regional markets in the U.S., but will apply contract path constraints in their market clearing engines when necessary to respect the rights of non-member entities and the impact of their market on neighboring systems. For example, the Markets+ tariff section 2.1.2 states that:

> The Market Operator will employ a Simultaneous Co-optimization Methodology to perform the following tasks to clear the Day-Ahead Market for each hour of the upcoming Operating Day, while recognizing transmission system security constraints, Service Flow Constraints, and the Resource operating parameter constraints submitted as part of the Day-Ahead Market Offers….[6]

Where a Service Flow Constraint is defined as:

> An operating constraint limit that respects each Markets+ Transmission Contributor's and each Markets+ Transmission Service Provider's transmission capability. Service Flow Constraints will be continuously activated in the Simultaneous Co-optimization Methodology to constrain the least cost dispatch to the transmission capability made available for use in Markets+.[7]

In other words, the Markets+ clearing engine will consider Service Flow Constraints that reflect contractual transmission rights made available by its members.[8]

Had a purely flow-based market optimization been proposed, it is likely that the FERC would have required EDAM or Markets+ to include contract path-based constraints in their market clear engines, since multiple parties commonly hold rights to use transmission capacity on the same physical assets in the WECC. Ignoring contract path rights in regional market clearing engines can result in commitment and dispatch decisions that create negative outcomes for neighboring entities. For example, a market dispatch solution using a transmission asset beyond the contracted capacity can create congestion on the asset and impair the utilization of other

6 Southwest Power Pool, Inc., *Markets+ Tariff*, Section 2.1.2, March 29, 2024.

7 Southwest Power Pool, Inc., *Markets+ Tariff*, Section I.1.S—Definitions, March 29, 2024.

8 The EDAM tariff indicates that its clearing engine will consider contract path constraints in its optimization. Specifically, Section 33.7.2 states that "The CAISO will model individual constraints for each EDAM Transfer scheduling limit available on an EDAM Internal Intertie based on the transmission capacity made available under Section 33.18 and will enforce the scheduling limit for an EDAM Transfer in the Day-Ahead Market." Section 33.18 describes procedures for EDAM members to volunteer their contractual transmission rights into the market. California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Section 33.7.2, Docket ER23-2686-000, August 22, 2023.

parties' transmission rights. This congestion could not only preclude other rights holders from using the asset but force a re-dispatch in the neighboring system and potentially reduce revenues of resource owners and increased costs for load in neighboring systems.

An example of the consequences of ignoring contract path limitations in market-based dispatch is provided by the integration of Entergy into MISO (now known as MISO-South) in the early 2010s. MISO initially dispatched its system without contract path constraints between Entergy and its Midwest service territory (MISO-North), despite limited MISO contract path transmission between the two regions. This dispatch created substantial parallel flows on the neighboring systems, leading SPP[9] to file a complaint with the FERC stating that "significant intentional, unscheduled incremental power flows are crossing SPP's system without any corresponding reservation, service agreement, or compensation."[10] Ultimately a solution was reached that imposed a limit on transfers between the MISO-South and MISO-North service territories, with FERC explaining that "MISO will take certain actions to limit or control its dispatch based on agreed upon operating limits without reaching the System Operating Limits (SOL) on the transmission systems of any of the parties in real-time."[11] This arrangement persists today, with the MISO market clearing engine obeying a contract-path limit between the MISO-North and MISO-South service territories.[12]

While stakeholders have raised concerns that the use of contract path constraints in the market clearing will result in inefficiencies in market outcomes, the MISO-South integration example and the FERC's ruling imposing a contract path limit between MISO-North and MISO-South demonstrates the negative consequences of *not* applying contract path constraints where appropriate and that the FERC will likely mandate the alleviation of such negative consequences. If stakeholders are concerned about the inefficiencies created by the application

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9 The Tennessee Valley Authority (TVA) and PJM Interconnection LLC (PJM) filed similar complaints. Federal Energy Regulatory Commission, *Order Approving Merger and Acquisition and Disposition of Jurisdictional Facilities, and Granting Petition for Declaratory Order,* Docket Nos. EC12-145-000 and EL12-107-000 at 100, June 20, 2013.

10 Southwest Power Pool, Inc., *Complaint and Request for Fast Track Processing and Motion to Consolidate*, Docket No. EL14-21-000, January 28, 2014.

11 Federal Energy Regulatory Commission, *Order Approving Operations Reliability Coordination Agreement*. Docket No. ER13-2162-000, October 10, 2013, ¶ 9.

12 FERC notes that "Entergy Arkansas, Ameren Corporation (Ameren), and Associated Electric Cooperative, Inc. (Associated Electric) are parties to an interconnection agreement under which they share the capacity of the 500/345 kV transformers on a high-voltage interconnection. The direct contiguous tie capability between Entergy Arkansas and Ameren is approximately 1,000 MW of the 1,500 MW total capability of the interconnection (i.e., the 1,000 MW contract path limit)."
Federal Energy Regulatory Commission, *Order Accepting Tariff Revisions, Subject to Condition,* Docket No. ER16-56-000, January 21, 2016, fn 13.

of contract path constraints in the markets, the best way to limit their use would be for the entire WECC to join the same market. This would bring all the physical transmission assets under the control of a single market operator, thereby reducing the need for contract path constraints. Moving towards a joint transmission tariff or a full regional transmission organization (RTO) would further reduce, and possibly eliminate, the need for contract path constraints altogether.

III. Fast Start Pricing

Fast start pricing (FSP) refers to the inclusion of the start-up and no-load costs from fast start resources in the formation of market prices. The Markets+ tariff filed with the FERC indicated that its market clearing will include FSP, which is consistent with SPP's market engine.[13] The EDAM will be cleared using the CAISO's market engine, which does not currently include standard FSP. The CAISO market engine allows for fully block-loaded resources to set prices, while FSP would extend that to fast start resources that have a minimum generation level greater than zero.[14] Some stakeholders have presented analyses suggesting that FSP has a substantial impact on market prices and revenues collected by generation resources that can come online quickly ("fast start resources"). However, evidence from several U.S. markets, including SPP, indicates that FSP has a very minimal impact on market prices, impacts relatively few hours, and does not materially increase the market revenues of fast start resources.

Regional markets set energy and ancillary service prices based on the marginal cost of serving incremental load or procuring incremental operating reserves, accounting for line losses and transmission constraints. Except during periods of very high renewable energy production, market prices are typically set based on the marginal cost of thermal resources. The marginal cost of thermal resources is determined primarily by their variable costs, such as fuel and variable maintenance costs. Thermal resources also have startup and no-load costs, which do not typically contribute to their marginal cost of serving load because they are incurred regardless of the operating output of the plant. Many thermal resources operate continuously

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[13] The Markets+ tariff indicates that the market clearing engine will produce both a dispatch and a pricing solution. The pricing solution amortizes fast start resources' startup and no-load costs over their minimum runtime and relaxes the minimum generation constraint to ensure that these resources can set prices. Southwest Power Pool, Inc., *Markets+ Tariff*, Section 3.1, March 29, 2024.

[14] The CAISO has an ongoing initiative on price formation enhancements that is exploring the application of FSP in its markets. *See* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Price-formation-enhancements.

for many hours or days and have marginal costs that are typically below market clearing prices, which allows them to recover their startup and no-load costs over their entire running periods, regardless of whether those costs are accounted for in market prices.

The same is not true for fast start resources, which can start quickly to provide surge capacity but may be called on to operate for as little as an hour or less, due to their higher operating costs. Given their short runtimes between starts, fast start resources' startup and no-load costs account for a large portion of their per-MWh cost of generation relative to longer-running thermal resources. However, fast start resources typically have high minimum dispatch levels, precluding them from setting market clearing prices under legacy approaches to market price formation. Thus, fast start resources have typically been eligible to receive out-of-market uplift payments to compensate for unrecovered costs.

Multiple markets devised different approaches to FSP to create more efficient price signals that properly account for the full marginal cost of fast start resources. Under FSP, the market operator conducts the typical market clearing optimization, then follows it up with a "pricing run" in which certain constraints are relaxed to allow fast start resources to set prices. FSP has been a feature of multiple US market clearing engines for years, coming into effect in MISO on March 1, 2015,[15] in ISO-NE on March 31, 2017,[16] and SPP on May 18, 2022.[17]

Analyses by the MISO independent market monitor (IMM) and the ISO-NE's internal market monitor (ISO-NE IMM), and SPP's market monitoring unit (MMU) indicated the overall frequency and magnitude of the price impacts of FSP were very small. The PJM IMM has also indicated that FSP potentially undermines the objective of reducing production cost, and its implementation in the PJM market has distorted efficiency.[18]

A year after implementation in MISO, the IMM determined that FSP affected only around 7.2% of real-time clearing intervals, impacting market-wide real-time prices by an average of only

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15 Federal Energy Regulatory Commission, *Order Conditionally Accepting Tariff Revisions,* Docket No. ER15-684-000, February 27, 2015.

16 Federal Energy Regulatory Commission, *Tariff Revisions to Fast Start Resource Pricing and Dispatch*, Docket No. ER-15-2716-001, October 19, 2015.

17 Federal Energy Regulatory Commission, *Compliance Filing Revising Fast Start Pricing Practices,* Docket No. ER-20-644-001, October 27, 2020.

18 Monitoring Analytics, 2021 Quarterly State of the Market Report: January through June, August 12, 2021, p. 114. Monitoring Analytics, PJM Members Committee Webinar, July 22, 2024, p. 8.

$0.03/MWh in 2015.[19] In addition to the small impact on real-time prices, the MISO IMM concluded that FSP had virtually no impact on day-ahead energy prices.[20] A year later, the MISO IMM again found similar outcomes that FSP affected only around 7.7% of real-time clearing intervals, impacting market-wide real-time prices by an average of $0.01/MWh in 2016.[21] The MISO IMM, again, found no impact on 2016 day-ahead market prices.[22]

Similarly, the SPP MMU found that FSP had only very small impacts on market prices, which increased fast start resources' day-ahead energy revenues by around 1.5% and real-time energy revenues by around 0.5%—a negligible impact on fast start resource compensation.[23] ISO-NE IMM's analysis of FSM found larger impacts, although that analysis is limited to the first eight months after FSP came into effect. It found that in the eight months after FSP came into effect, average system energy prices increased by 11%, or $2.72/MWh, with 42% of intervals seeing a price impact.[24] The ISO-NE IMM noted a marked reduction in generator make-whole payments after the implementation of FSP and attributed over half of the reduction to FSP. [25]

The real-world experience from these markets is in stark contrast to analyses from a whitepaper released by Powerex (PWX) and the Public Power Council (PPC). The analysis in that whitepaper, conducted by Energy GPS, suggests that during 2017–2020 the impact of FSP would have resulted in average energy price impacts of $15–$23/MWh and $1.2–$2.0 billion in

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19 The Market Monitor's report states that accounting for the startup and no-load cost of fast start units that are already running affected 6.3% of market clearing intervals, producing an average price increase of $0.08/MWh. On the other hand, allowing offline fast start units to set prices altered prices in 0.9% of market clearing intervals, producing a $0.11/MWh decrease in real-time energy prices by reducing or eliminating shortage pricing outcomes. These opposite impacts net out to a $0.03/MWh <u>decrease</u> in average real-time energy prices. Potomac Economics, *2015 State of the Market Report for The MISO Electricity Markets*, June 2016, Section V.B.

20 *Ibid.*

21 Potomac Economics, *2017 State of the Market Report for The MISO Electricity Markets*, June 2017, Section V.B.

22 *Ibid.*

23 The SPP MMU noted that around 25% of real-time market intervals were affected by fast start pricing logic updates but did not specify the extent of those effects and whether they increased or decreased energy prices. Southwest Power Pool Market Monitoring Unit, *State of the Market 2022*, May 15, 2023, Section 3.1.3.

Southwest Power Pool Market Monitoring Unit, *State of the Market: Fall 2022*, February 6, 2023, Section 6.

24 ISO New England Inc. Internal Market Monitor, *2017 Annual Markets Report*, May 17, 2018Section 8.1.
ISO New England Inc. Internal Market Monitor, Summer *2017 Quarterly Markets Report*, December 20, 2017, Section 5.3.

25 The ISO-NE IMM report states that generator uplift payments decreased from $73 million in 2016 to $52 million in 2017 as there were fewer localized reliability commitments in certain areas and as fast start pricing came into effect. The IMM estimates that around $11.9 million of the $21 million total reduction in uplift payments arose due to fast start pricing. ISO New England Inc. Internal Market Monitor, *2017 Annual Markets Report,* May 17, 2018, Sections 1.1, 1.3.

additional annual market revenues to generation resources.[26] The analysis informing this whitepaper calculated price fast start units' impacts on energy prices as the difference between the marginal cost of starting and running peaking units and the average energy price at regional pricing hubs (NP15 and SP15 in CAISO, plus the Southwest and Northwest regions). The study did not simulate a counterfactual market commitment and dispatch solution for the CAISO market to validate this impact, which falls short of the analytical rigor of the analysis conducted by the independent market monitors for the MISO, SPP, and ISO-NE markets. Furthermore, the study does not differentiate between locational marginal prices (LMPs) at individual nodes and averaged hub prices, inappropriately concluding that localized price impacts due to peaking unit startups can directly set regional market prices. Fast start pricing would have an effect on LMPs at the specific node where a peaking unit is located and other nodes that are not congested relative to the peaking unit node. Hub prices like the NP15 and SP15 are designed to represent regional market conditions and are therefore average energy prices from numerous nodes on the power grid. It is inappropriate to conclude that a localized nodal price impact due to fast start pricing would also have a significant impact on hub electricity prices. The averaging involved in computing hub prices would dilute the impacts of localized fast start pricing. This effect is apparent when comparing the results from the PWX and PPC whitepaper (projecting large price impacts) to the evidence presented by several market monitors, showing only minimal price impacts based on the real-world FSP experience from regional markets in the eastern U.S. This real-world experience in other market is consistent with the much smaller impacts estimated in the CAISO FSP's analysis.[27]

While the evidence from eastern power markets demonstrates that the impact of FSP is very modest, the impact on specific market participants may vary. Market participants that are long on generation may earn slightly more revenue in a market with FSP, although the evidence from MISO suggests that FSP may decrease market prices if the impact of FSP reduces the frequency of scarcity events. Market participants that are short on generation or have high load in hours affected by FSP would face slightly higher net power costs to serve their customers. However, most WECC utilities have relatively balanced load and generation because they conduct individualized resource planning efforts designed to align long-term supply and demand. Therefore, for most utilities in the WECC it is unlikely that FSP (or the lack of it) would markedly increase or decrease the cost or benefit of participating in a regional wholesale

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[26] Powerex and Public Power Council, *The Importance of Fast Start Pricing In Market Design: Including The Cost Of Starting And Operating Natural Gas Peaking Units In Wholesale Market Prices,* June 2022.

[27] The California Independent System Operator, "Analysis of Fast Start Pricing for ISO's Real-Time Market," December 18, 2023. Accessed at https://www.caiso.com/documents/presentation-faststartpricing-dec18-2023.pdf.

market. Further, FSP will have minimal impacts on resource investment because its price impacts are modest and most investment decisions in the WECC are made by vertically integrated utilities through integrated resource planning efforts.

IV. Look Ahead and Real-Time Commitment

The look ahead period, in the context of market clearing, refers to the forecast of system conditions beyond the specific intervals that are being optimized in each solution of a market clearing engine. All market clearing engines include some look ahead period because it allows market operators to serve demand more reliably in the current intervals while positioning the system to maintain efficient and reliable operations under anticipated future system conditions. The CAISO's real-time operations that are used to clear the WEIM, which all EDAM members will participate in as their real-time market,[28] includes a four-hour look ahead period. The WEIM's four-hour look ahead also enables real-time unit commitment (RTUC) in its market optimization algorithm.[29] The SPP real-time market clearing engine, as used in the WEIS today, and as described in the Markets+ tariff does not include a look-ahead nor does it perform unit commitment, relying instead on manual short-term unit commitment decisions by market members. The SPP market clearing process does include an optimized or reliability unit commitment (RUC) that operates intra-day every four hours, after the day-ahead market and before real-time.[30]

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28 EDAM participation will only be open to WEIM members. The CAISO's EDAM tariff transmittal letter states that "pursuant to its Extended Day-Ahead Market (EDAM) initiative, the CAISO proposes tariff revisions to extend access to its day-ahead market to balancing areas in the WEIM that elect to participate in the day-ahead market." California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market Transmittal Letter*, Docket ER23-2686-000, August 22, 2023.

29 The EDAM tariff states that "Once per hour, near the top of each Trading Hour, immediately after the FMM and the RTUC for the same interval is completed the CAISO performs a Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast of CAISO Demand over a 270-minute time horizon to commit Short Start Units, with Start-Up Times greater than the time period covered by the RTUC described in Section 34.3. In any given Trading Hour, the STUC may commit resources for the third fifteen-minute interval of the current Trading Hour and extending into the next four (4) Trading Hours. The STUC looks ahead over a period of at least three (3) hours beyond the Trading Hour for which the RTUC optimization was run." California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket ER23-2686-000, August 22, 2023, Section 34.6.

30 The Markets+ tariff states that "following execution of the Simultaneous Co-Optimization Methodology, the Market Operator will communicate the following [Real-Time Balancing Market] results to Market Participants for only their specific Resources prior to the start of the applicable Dispatch Interval: (a) Resource Dispatch Targets; and (b) Cleared Flexibility Reserve Products. (c) Cleared attributed GHG MWh quantities for Internal

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We expect EDAM members to see improved real-time market efficiency and reliability relative to Markets+ members because of the WEIM's optimized RTUC process. By definition, centrally optimized RTUC of EDAM members' generation resources would find more economically efficient commitment solutions to address emerging market conditions. Compared to de-centralized and manual real-time unit commitment processes, the WEIM's RTUC solution analyzes all possibilities in the market footprint subject to system constraints, which allows for the lowest-cost generation capacity feasible to be committed in real-time while obeying all system constraints and minimizing congestion and loss impacts. Further, using a four-hour look ahead to optimize RTUC helps the market operator to address reliability concerns and changing system conditions, including variability in renewable resources and load more proactively, by procuring supply, ramping, and reserve capacity.

Without centralized optimization, the manual real-time unit commitment decisions made by Markets+ members will likely be less efficient. These manual commitments may produce increased transmission congestion and will be more reactive by nature as they are made without the benefit of an extended (multi-hour) look ahead optimization based on forecasts of real-time system conditions throughout the entire market footprint.

While there is limited evidence available from the CAISO or other markets on the impact of a longer look ahead period and optimized RTUC, we anticipate that the four-hour look ahead and regionally optimized RTUC process in WEIM will be able to achieve a lower-cost market outcome and improved reliability for members and their customers than manual real-time unit commitment decisions made under Markets+. Adding multi-hour look ahead to its real-time optimization to enable the real-time market engine to perform unit commitment is a market design enhancement that Markets+ members may want to consider in the future.

V. Regional Economic Procurement of Imbalance and Flexibility Reserves

One way participating in a regional wholesale market enables customer benefits is through reduced reserve requirements and more efficient procurement of reserves. In EDAM and

GHG Resources and Specified Source Resources, (c) Cleared attributed Import Interchange Transaction MWh by GHG zone; and (d) Unspecified Source Imports by GHG zone." The tariff makes no mention of unit commitment decisions being a result of the Real-Time Balancing Market Simultaneous Co-Optimization Methodology. Southwest Power Pool, Inc. *Markets+ Tariff*, March 29, 2024, Section 2.3.1.3.

Markets+ customers will see this benefit with respect to Imbalance Reserve and Flexibility Reserve, respectively. This occurs in two ways. First, regional market participation lets individual members hold fewer operating reserves without sacrificing reliability because the diversity of load and renewable resources across the market footprint is greater than within each member's service territory. Members of both the EDAM and Markets+ will be able to benefit from the net load diversity in the market and hold fewer imbalance or flexibility reserves. Second, regional markets can also procure reserves collectively for the entire footprint (across all members) based on the relative economics of all the resources available in the market that can provide those reserve types, subject to transmission and deliverability constraints. Procuring reserves from potentially lower-cost resources outside of a member's service territory can thus potentially lower the cost of holding reserves relative to self-supply. Both EDAM and Markets+ will provide customers with these benefits by implementing market-wide reserve products that address uncertainty between day-ahead net load forecasts and real-time actuals.

Under the EDAM, this reserve product is called the Imbalance Reserve Requirement. It is calculated based on the 2.5th and 97.5th percentiles of "the anticipated levels of upward and downward Net Load Forecast [accounting for load, wind, and solar] deviations between the Day-Ahead Market and the Fifteen-Minute Market, respectively, within a specified confidence interval."[31,32] Imbalance reserve requirements are calculated for each individual BAA and the whole market. The difference between the sum of all BAAs' requirements and the market-wide requirement is referred to as the "Diversity Benefit" and is proportionally allocated among EDAM member BAAs to reduce individual imbalance reserve requirements.[33] The geographic diversity of net load and the market-wide "Flexibility Reserve Product" under Markets+ would enable similar operational savings to those described above for the EDAM.[34]

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[31] California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket ER23-2686-000, August 22, 2023, Section 31.3.1.6.1.

[32] The EDAM tariff transmittal letter states that "the CAISO has modeled calculation of the imbalance reserve requirement based on its existing methodology for establishing flexible ramping product requirements in the real-time market." California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket ER23-2686-000, August 22, 2023, Section 3.a, p. 69.

[33] The EDAM tariff states that "for each Balancing Authority Area participating in the Day-Ahead Market, the CAISO reduces the Balancing Authority Area's hourly Imbalance Reserves Requirement by its proportional allocation of the Diversity Benefit for EDAM." California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket ER23-2686-000, August 22, 2023, Section 31.3.1.6.1.

[34] The Markets+ tariff states that "Flexibility Reserve Products include Short-Term Flex Up, Short-Term Flex Down, and Mid-Term Flex Up." Southwest Power Pool, Inc. *Markets+ Tariff*, Section I.1.F—Definitions. March 29, 2024. The Markets+ tariff states that "the Market Operator will calculate the amount of Flexibility Reserve Products required for the Operating Day, on both a Markets+ Footprint and Reserve Zone basis." Southwest Power Pool, Inc., *Markets+ Tariff*, March 29, 2024, Section 7.3.

Both EDAM and Markets+ will also conduct market-wide procurement of these two specific reserve types (Imbalance Reserve in EDAM and Flexibility Reserve in Markets+). Markets+ reserve procurement will be structured on a zonal basis to ensure that all Flexibility Reserves procured in the market will be deliverable when deployed.[35] Reserve requirements will be calculated on a footprint-wide level and a zonal level to determine appropriate local procurement targets within each zone.[36] Similarly, in EDAM, Imbalance Reserve will be procured for the entire footprint subject to deliverability constraints.[37,38]

Therefore, as currently designed, both markets will deliver cost savings to customers through market-wide procurement of Imbalance or Flexibility Reserves, allowing the market to benefit from net load diversity between market members. Stakeholders in both markets should consider extending market-wide procurement to other reserve types and Ancillary Services, which would likely increase customer savings.

VI. Seams Optimization

Most regional markets in the U.S. allow markets participants to offer buy and sell bids for imports and exports at their seams (known as intertie trading), which provides a clear price signal for the market clearing engine to dispatch imports or exports along with internal generation and load and achieve a more efficient market outcome. The Markets+ design requires intertie trading on all members' systems if they form part of the external seam of the market, if the market participants submitting an intertie bid procure transmission from the

[35] The Markets+ tariff states that "the Market Operator will identify the need for Reserve Zones within the Markets+ Footprint through Reserve Zone studies that identify constrained areas that may require a minimum amount of Flexibility Reserve Products procurement and/or that may be limited to a maximum amount of Flexibility Reserve Products procurement to ensure market- wide procurement of Flexibility Reserve Products is deliverable when deployed." Southwest Power Pool, Inc., *Markets+ Tariff*, March 29, 2024, Section 7.3.

[36] The Markets+ tariff states that "the Market Operator will calculate the amount of Flexibility Reserve Products required for the Operating Day, on both a Markets+ Footprint and Reserve Zone basis." Southwest Power Pool, Inc., *Markets+ Tariff*, March 29, 2024, Section 7.3.

[37] California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket ER23-2686-000, August 22, 2023, Section 31.

[38] The CAISO also procures Flexibility Ramp Product market-wide across the entire WEIM. *See* California Independent System Operator, *Open Access Transmission Tariff*, Effective August 1, 2024, Section 44. This capability will be extended to the EDAM.

source to sink prior to submitting their bids.[39] While the CAISO allows for intertie bids and optimizes them in their market clearing engine, the same process will not exist at the seam of the EDAM outside of the CAISO BAA unless members whose systems form part of the market seam opt in.[40]

The more efficient intertie trading offered through the Markets+ design will likely increase benefits for market members. A 2023 Brattle study found that optimized real-time trading across market seams would make 20–30% of the total value of interregional transmission available to transmission rights holders and regional power market customers.[41] The responsiveness of centrally optimized seams trades to market conditions allowed market operators to unlock additional transmission value that would not have been accessible to bilateral traders. Evidence from multiple market monitors shows that power flows are often inconsistent with energy price differentials across market seams, causing regions with high energy prices to send power to regions with low energy prices.[42] These inconsistencies arise because system conditions and cross-seam energy price differentials change in the time between scheduling and execution of bilateral trades.[43] Allowing for better-optimized trading

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39 The Markets+ tariff states that "Market Participants may submit offers to sell Energy into the Day-Ahead Market, Real-Time Balancing Market (RTBM), or both, delivered from a source located outside of the Markets+ Footprint. Import Interchange Transaction Offers will be evaluated based on the external source as identified on the e-Tag." It also states that "An Export Interchange Transaction Bid is required to have an associated transmission service reservation(s) from the source identified in the e-Tag to the applicable External Interface." Southwest Power Pool, Inc., *Markets+ Tariff*, March 29, 2024, Section 4.3.1.

40 The EDAM tariff states that "Except for resource-specific resources with an obligation to serve Demand in the EDAM Area described in Section 33.30.8, a Scheduling Coordinator for a designated resource associated with network integration transmission service of an EDAM Transmission Service Provider, or a resource located outside of the EDAM Area at an EDAM External Intertie with the CAISO Balancing Authority Area, may not submit Economic Bids at EDAM External Interties or EDAM Internal Interties unless the submission of Economic Bids has been enabled in accordance with Section 29.34(i)(2)." California Independent System Operator. *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket ER23-2686-000, August 22, 2023, Section 33.30.3.

41 Pfeifenberger, DeLosa III, Gonzalez, Bay, Chum (The Brattle Group, Brattle), *The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission*, October 2023. https://www.brattle.com/wp-content/uploads/2023/10/The-Need-for-Intertie-Optimization-Reducing-Customer-Costs-Improving-Grid-Resilience-and-Encouraging-Interregional-Transmission-Report.pdf

42 The PJM IMM found that in 2022, energy price differences between PJM and NYISO changed signs 3.1 times per day on average. Real-time price differences across this seam changed almost 48 times per day, on average, in 2022. Real-time price differences between PJM and MISO changed signed almost 63 times per day, on average, in 2022.
Monitoring Analytics, *2022 State of the Market Report for PJM,* March 9, 2023, Table 9-30.

43 Analyses by PJM's IMM show that 2022 power flows were inconsistent with price differences during 4,176 hours (or 48%) of the year. These price differences across the MISO-PJM seam exceeded \$10/MWh during 3,182 hours; yet during 1,570 (49%) of these hours, market flows were inconsistent with those price differences, exporting power from the higher-priced market to the lower-priced market. Similarly, on interties

Continued on next page

across seams that is responsive to market conditions and prices would create more efficient outcomes for market participants.

Optimizing intertie trading by default in Markets+ will facilitate more efficient trading at the seams. On the other hand, the EDAM opt-in structure may limit market benefits to customers. If all EDAM members opt into optimized intertie trading, we anticipate market benefits to increase. We therefore recommend that EDAM members consider enabling intertie trading.

More broadly, given the potential for greater customer benefits and higher reliability during shortage conditions, we recommend that both markets consider further collaboration to increase the efficiency of trading across their seams. Possibilities for collaboration include joint operating agreements, co-optimized seam management, or even a joint real-time energy imbalance market.

VII. GHG Pricing Mechanisms

The EDAM and Markets+ market designs include constraints in their market clearing engines and other mechanisms to ensure that the market accounts for the price of GHG emissions when it transfers power into states that have GHG pricing policies and the specific emissions from the resources that the markets deem to serve load in those states.[44] The mechanisms in the two markets differ significantly, with the EDAM building off the mechanism already in place in the WEIM, while Markets+ aims to implement a new design. There are potential pros and cons in each approach. Specifically, because the EDAM approach builds off the WEIM, it benefits from ten years of experience, scrutiny, and a series of improvements made to the mechanism

between PJM and NYISO, 2022 market flows were inconsistent with price differences during 3,463 hours (or 40%) of the year. Price differences exceeded $10/MWh during 4,178 hours; yet flows were inconsistent with those price differences during 1,667 (40%) of these hours. This pattern was also confirmed by Potomac Economics, which noted in the MISO 2021 State of the Market Report that, going across the RTO seams, "more than 40 percent of the current…transactions are ultimately unprofitable."
Monitoring Analytics, *2022 State of the Market Report for PJM*, March 9, 2023, Tables 9-27 and 9-29.
Potomac Economics, *2021 State of the Market Report for the MISO Electricity Markets*, June 2022, p. 90.

44 There are several other aspects of GHG accounting and reporting related to regional power markets that these GHG pricing mechanisms do not address. For example, several states in the WECC have GHG reduction policies that do not include an explicit price on GHG emissions. Utilities in those states cannot be assured that the GHG pricing mechanisms included in the EDAM and Markets+ clearing engines will produce market outcomes that are compliant with their state policies. There are initiatives currently under way for Markets+ and the EDAM to develop additional GHG accounting practices and protocols to address these issues. This whitepaper only addresses the impact of the GHG pricing mechanisms, as stated in the Markets+ and EDAM tariff language.

developed through engagement between the CAISO, the California Air Resource Board (CARB), market participants, and other stakeholders. The Markets+ approach is new, having been developed largely from scratch in the last two years. It does not build off an existing approach and therefore does not benefit from the same operational experience, regulatory scrutiny, and incremental improvement that the WEIM/EDAM approach does. Nor are there ten years of data on its performance on which we can judge its effectiveness. However, as a novel approach, the Markets+ approach provides more flexibility for market participants than the EDAM approach, but with the added flexibility comes more complexity, uncertainty, and risk in market and emissions outcomes depending on what options market participants choose.

The EDAM approach is defined by two constraints added to the market clearing engine and a pre-market simulation (the GHG reference pass) that informs those constraints. The GHG reference pass simulates the market without any transfers of energy from non-GHG pricing states to GHG pricing states and establishes a baseline level of dispatch for all resources outside of GHG pricing states and a baseline level of net exports from each BAA outside of GHG pricing states.[45] These two outcomes of the GHG Reference Pass are inputs into the two constraints used during market clearing.

The first constraint limits how much output from each generation resource located outside of GHG pricing states can be sold into GHG pricing states (attribution). The constraint limits GHG attribution to the lesser of three components: 1) the MWs offered by the resource for sale into the GHG pricing states, 2) the difference between the upper economic limit and its level of dispatch in the GHG reference pass, and 3) the resource's Day-Ahead energy schedule as determined by the final market clearing.[46] The second constraint imposes a limitation on the sum of GHG attribution for all resources located in the same EDAM member BAA (outside of GHG pricing states). The constraint limits the sum of GHG attribution inside each member BAA to the quantity of net exports from that BAA that are incremental to the BAA's net exports in the GHG reference pass.[47]

The EDAM approach allows market participants to opt-out of selling into GHG pricing states, by submitting an offer of zero MWs eligible for sale into the GHG pricing states. However, all resources that submit an offer with a positive number of MWs available for sale into the GHG

[45] CAISO Tariff Section 33.32,2,3. In the WEIM, a resource's Base Schedule serves the same purpose of establishing a baseline level of production as an input into constraints in WEIM's real-time market clearing engine. The GHG reference pass was developed for the EDAM, as Base Schedules (or something comparable) will be available for use in day-ahead market clearing.

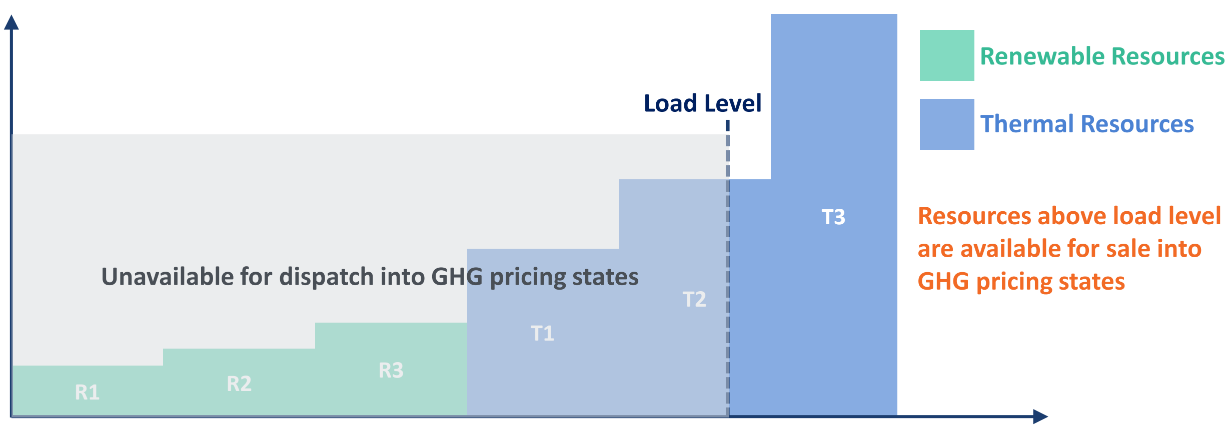
[46] *Id.*, Section 33.32.2.2.

[47] *Id.*, Section 33.32.5.

pricing states are treated the same based on the same set of constraints. In this way, the EDAM approach differs from the Markets+ approach that provides for multiple options for resources to be eligible to sell into the GHG pricing states.

The Markets+ approach provides participants with generation resources located outside GHG pricing states two options for offering those resources into GHG pricing state.[48] Market participants can select between the Resource Owner and Merit Order options. The Resource Owner option allows generation owners to determine prior to market clearing how much capacity from each of their resources will be offered into GHG pricing states. If a market participant selects the Merit Order, the market will, for each hour in the market clearing, create a supply stack based on the offers made into the market for all their generation resources and only offer resources above their expected load into GHG pricing states. See Figure 1 for a simple example of the Merit Order approach.[49]

FIGURE 1: EXAMPLE OF MARKETS+ MERIT ORDER APPROACH'S DETERMINATION OF ELIGIBILITY TO SELL INTO GHG PRICING STATES



As in the EDAM approach, Markets+ will employ an additional simulation to accompany the market clearing engine, called a GHG Threshold Run, that establishes a baseline level of generation for all resources located outside the GHG pricing state. There are two main ways in which the Markets+ GHG Threshold Run differs from the EDAM GHG Reference Pass.

- First, the EDAM GHG Reference Pass does not allow any power to be sold from non-GHG pricing states to GHG pricing states, which produces a baseline level of dispatch for resources in the non-GHG pricing states, assuming that they are not used to serve load

48 Certain generation resources physically located outside of GHG pricing states may qualify to be treated as in-state resources based on regulations in the GHG pricing states (known as Type 1 resources). The two options described in this whitepaper apply to generation resources located outside GHG pricing states that do not meet the criteria to be treated as internal by a GHG pricing state (Type 2 resources).

49 Southwest Power Pool, Inc., *Markets+ Tariff*, March 29, 2024, Attachment K, Section 3.

inside GHG pricing states, while allowing for market optimization to occur outside the GHG pricing states. The Markets+ GHG Threshold Run does not impose limits on transfers into GHG pricing states, so the baseline dispatch it determines may include leakage where renewables outside the GHG pricing states are transfers into the GHG pricing states and backfilled with thermal resources outside GHG pricing states. This reflects the fact that the Markets+ GHG Threshold Run serves a different purpose than the EDAM Reference Pass Run. The EDAM Reference Pass is meant to establish a baseline dispatch level free of leakage to help prevent it in the final market clearing. The Markets+ approach primarily relies on the Resource Owner or Merit Order approach to limit leakage, which are applied prior to the GHG Threshold Run.

- Second, the EDAM GHG Reference Pass establishes a baseline level of generation for each resource outside GHG pricing states, and only capacity above that level for that resource can be attributed to the GHG pricing state in the final market clearing run. Under the Markets+ approach, the total amount of baseline dispatch established by the GHG Threshold Run is eligible for attribution to the GHG pricing states in the final market clearing, if that capacity has been offered under the Resource Owner approach or clears the Merit Order approach.[50]

Figure 2 and Figure 3 illustrate two examples of how the Markets+ and EDAM approaches differ. Figure 2 shows an example with a 100 MW resource located outside GHG pricing states. In this example, the entire capacity of this resource is available to sell into GHG pricing states, either because all its capacity was offered that way by the resource owner (in the EDAM or in Markets+ under the Resource Owner approach) or because, in Markets+, it cleared the Merit Order approach. The Markets+ GHG Threshold Run and the EDAM GHG Reference Pass dispatch the resource at 85 MW. In Markets+ that means the final market clearing would be free to attribute up to 85 MW from this resource to GHG pricing states if its dispatch level is at least as high as the quantity attributed, but its final market clearing could not attribute more than 85 MW to GHG pricing states even if the final dispatch of this resource was above 85 MW. In EDAM, up to 15 MW from this resource could be attributed to GHG pricing states, though only if the final dispatch of that resource is greater than 85 MW baseline dispatch from the GHG Reference Pass.

[50] *Ibid*.

FIGURE 2: MARKETS+ VS. EDAM GHG SURPLUS CALCULATION EXAMPLE 1

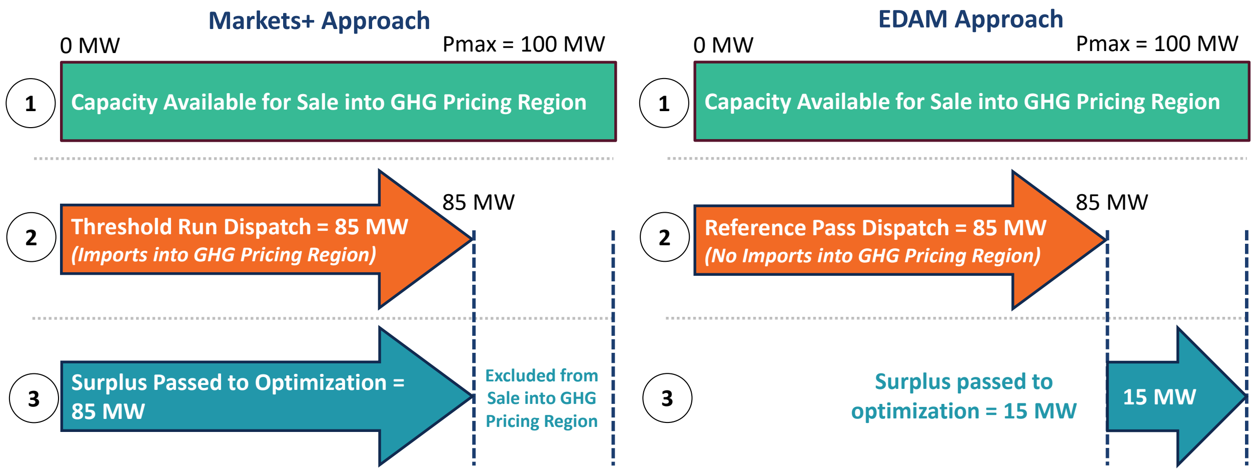
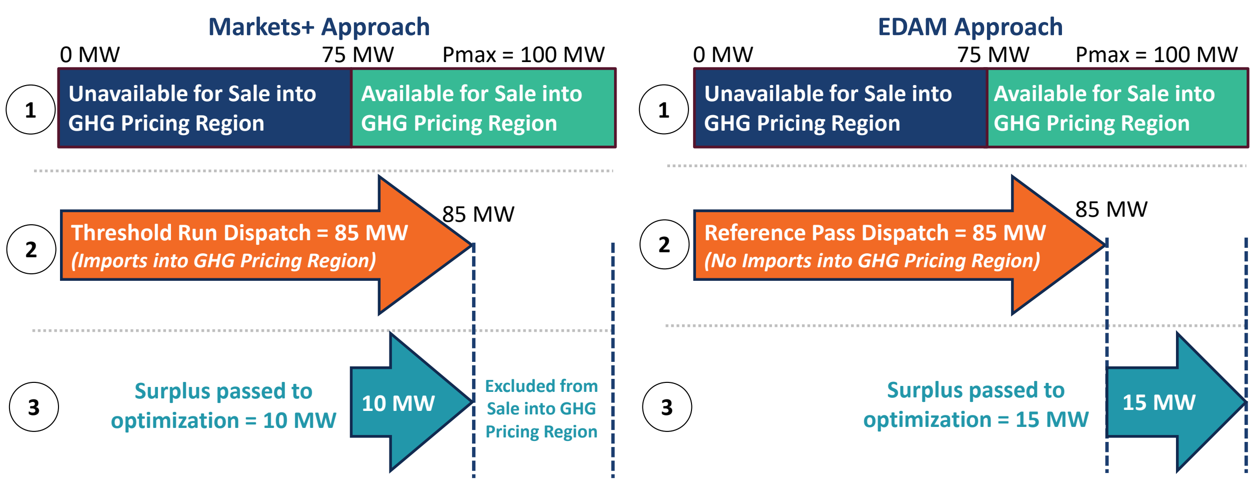


Figure 3 shows an example with a 100 MW resource, but where 75 MW of the resource is unavailable for sale to GHG pricing states, either because it was not offered or did not pass the Merit Order approach. The EDAM GHG Reference Pass and the Markets+ Threshold Run both dispatch the resource at 85 MW, the same as in Figure 2. The outcome in the EDAM approach is the same, up to 15 MW of the resource is available for attribution to GHG pricing states. In the Markets+ approach, only up to 10 MW are available for attribution to the GHG pricing states, which represents the difference between the GHG Threshold Run dispatch level and the amount of capacity unavailable for sale into GHG pricing states from the Resource Owner or Merit Order approach.

FIGURE 3: MARKETS+ VS. EDAM GHG SURPLUS CALCULATION EXAMPLE 2



As illustrated in Figures 1 through 3, the two approaches will produce different outcomes with respect to the amount of resources that can be sold into GHG pricing states and the amount of leakage potential created, which would impact the cost to serve load and the revenues received by generators in the respective markets. Given the option for market participants in Markets+

to select the Resource Owner approach or the Merit Order approach, the expected outcomes will vary significantly relative to the EDAM approach. We summarize a few important take aways for stakeholders in the WECC on the likely outcomes under each approach:

- The Merit Order approach under Markets+ is likely to be more restrictive with respect to the attribution of sales into GHG pricing states than the EDAM approach, which may lead to less leakage as well as higher cost outcomes for customers. For example, Figure 1 shows that under the Merit Order approach, resources with the lowest offers and self-scheduled resources into the market will not be eligible for sale into GHG pricing states, with renewable resources likely to be first in the merit order. The Merit Order approach will likely reduce attribution of renewables from non-GHG pricing states to GHG pricing states and help reduce leakage, because most renewables will not be available for sale into the GHG pricing states. However, the Merit Order approach could also restrict the potentially efficient sale of power from thermal assets into GHG pricing states. In Figure 1, we see that thermal resource T1 and part of T2 are eliminated by the Merit Order approach from selling into GHG pricing states. It may be feasible to achieve lower emissions and a lower-cost outcome for customers by selling the output of T1 into a GHG pricing state (accounting for GHG costs), backing down an inefficient and expensive thermal resource in a GHG pricing state, and using a lower-cost thermal resource in another area of the market to serve load outside the GHG pricing states. By restricting the use of T1 the market may end up relying on a higher-cost and higher-emitting resource inside a GHG pricing state, which would lower energy market revenues for T1, increase costs for customers in the market, and increase emissions. In addition, Figures 2 and 3 illustrate that none of the capacity above the level dispatched in the GHG Threshold Run is available for sale into GHG pricing states, even if the final market clearing run would have found it efficient to dispatch that resource at a higher level and attribute more of its output into GHG pricing states.
- Under the Resource Owner approach, the Markets+ approach may allow for significantly more leakage compared to the EDAM approach. Figure 2 illustrates the two reasons why this is can happen. First, the GHG Threshold Run does not include any constraints on what can be transferred between non-GHG pricing states and GHG pricing states. Second, because all the capacity dispatched in the GHG Threshold Run can be attributed to GHG pricing states in the final market solution if the resource is available for the sale into the GHG pricing states after the Resource Owner or Merit Order approach is applied. For example, if a Markets+ member makes all their capacity available for sale into the GHG pricing states under the Resource Owner approach, including all their renewable resources, the GHG Threshold Run will face no restrictions to limit leakage, and would be free to dispatch all that member's renewables, backing off emitting resources in GHG pricing states, and replacing them with other emitting resources outside the GHG pricing states to

find the lowest-cost feasible solution. All that renewable capacity could then be attributed to GHG pricing states without restriction while thermal resources outside GHG pricing states are used to serve that member's load. We expect regulators in GHG pricing states would find this outcome inconsistent with their policy objectives and would require changes to the GHG pricing structure in the market or develop restrictions on what resources Markets+ members can offer into their states.

The examples above illustrate the trade off between achieving the lowest-cost outcomes in the market and reducing leakage and illustrate how outcomes in Markets+ are likely to differ greatly with respect to this trade off depending on how members choose to participate and may be volatile if members frequently switch between the Resource Owner and Merit Order approaches for their resources. The market outcomes under the EDAM approach with respect to leakage are more certain, as the market rules give fewer options for participating than the Markets+ and will likely be in line with what has been experienced in the WEIM over the last several years. In fact, the trade off between achieving low-cost market outcomes and reducing leakage was recognized by the CARB in their 2016 critique of the WEIM structure. The CARB claimed that the initial WEIM structure implemented in 2014 focused only on least-cost dispatch and did not do enough to mitigate leakage.[51] The WEIM approach was subsequently modified to include constraints on market optimization to reduce the potential for leakage and the EDAM market rules include new constraints that aim to further reduce reshuffling (e.g., implementation of the Base Schedules constraints in the WEIM, the GHG Reference Pass in EDAM, and the aggregate BAA GHG Attribution constraint to be applied in EDAM).[52] Our analysis of the EDAM approach indicates that it minimizes reshuffling while delivering benefits to customers compared to the WEIM.[53]

Each market's approach to GHG pricing has specific advantages and disadvantages. The advantages of the EDAM approach are that it builds off the GHG pricing approach used in the WEIM, which has been in use for ten years and has benefited from several iterations and refinements with regulators, stakeholders, and market participants. The approach has been effective at limiting leakage, while still providing the flexibility for the market to identify resource dispatch opportunities that provide customers with cost reductions. The Markets+

[51] California Independent System Operator. Regional Integration California Greenhouse Gas Compliance. September 6, 2016. pp. 6–7. Accessed at https://www.caiso.com/documents/agenda-presentation-regionalintegrationcalforniagreenhousegascompliance-sep6_2016.pdf

[52] California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket ER23-2686-000, August 22, 2023, Sections 33.32.2.3 and 33.32.5.

[53] Tsoukalis, et al. *Extended Day-Ahead Market Benefit Study.* August 30, 2024. p. 5. Accessed at https://www.brattle.com/wp-content/uploads/2023/09/Extended-Day-Ahead-Market-Benefit-Study.pdf.

proposed approach has the advantage of providing market participants more flexibility in how they offer their resources for sale into GHG pricing states. However, this flexibility comes with the disadvantage of uncertain market outcomes and the possibility for either higher cost outcomes for customers or leakage, depending on how market participants choose to offer their resources for sale into GHG pricing states.

VIII. Congestion Revenue Allocation

In regional wholesale markets, payments from load are usually larger than payments to generators because transmission congestion tends to raise prices in load pockets and lower prices at locations with a large amount of generation. Therefore, market administrators typically collect more money than they distribute, and re-allocate these "congestion revenues" back to market participants. Markets+ and the EDAM have proposed to implement different approaches for allocating congestion revenue back to market participants. Some market participants may do better under Markets+'s proposed approach while others will do better under the EDAM's proposed approach. Both approaches may end up being very similar, depending on how the BAAs in the EDAM choose to suballocate congestion revenue to their transmission customers.

The Markets+ approach focuses on the contribution of each individual constraint in the market on system-wide congestion. The holders of transmission rights on binding constraints are directly allocated a share of the congestion revenue in the market proportional to the impact of that constraint on total market congestion.[54,55]

The EDAM differentiates between congestion revenues due to physical congestion ("EDAM Congestion Revenues") and contract path congestion between two market members ("EDAM

54 The Markets+ tariff defines "Congestion Rent" as the "revenue collected by the Market Operator resulting from binding transmission constraints in the Day-Ahead Market that will be allocated to Congestion Rent Eligible Transmission Service Reservation (CRETSR) Holders and Markets+ Transmission Service Providers," where the CRETSR is "the Megawatt (MW) quantity of Firm Point-to-Point Transmission Service, Conditional Firm Point-To-Point Transmission Service, Network Integration Transmission Service, and/or Legacy Transmission Service of a monthly or longer service increment that spans the full applicable calendar month, that has not been opted out, and is available for use by Markets+." Southwest Power Pool, Inc., *Markets+ Tariff*, March 29, 2024, Section I.1.C – Definitions.

55 The Markets+ tariff states that "A CRETSR Holder's Total Congestion Rent Allocation in an hour is calculated as follows: CRETSR Holder's Total Congestion Rent Allocation = the sum of that CRETSR Holder's Congestion Rent Allocations for all binding transmission constraints." Southwest Power Pool, Inc., *Markets+ Tariff*, March 29, 2024, Section 9.2.14.

Transfer Revenues"). Like congestion revenues collected in RTO markets around the US, **EDAM Congestion Revenues** are the difference between payments from load and payments to generators inside each EDAM member BAA. They are collected on a BAA level and allocated back to each member BAA.[56] Congestion collected on transfers between the EDAM member BAAs when their system marginal energy prices are different are called **EDAM Transfer Revenue**. It is calculated as the difference between the system marginal energy prices of the two transfer parties multiplied by the size of the transfer and is allocated to the two transferring BAAs or to the holders of transmission rights on the path between the two BAAs, if that arrangement is established by the EDAM entity BAAs.[57] Each EDAM member BAA will follow its own process for suballocating congestion and the transfer rents they are allocated by the CAISO.

There are two key takeaways when comparing the two approaches. First, neither approach should significantly alter the total amount of congestion revenue collected in the market. The amount of congestion revenue collected in the market, including both congestion caused by physical transmission limitations and congestion caused by contract path limitations between members, will reflect system conditions such as the generation mix and how much transmission is made available to the market, and is unlikely to change based on different methods of allocating it to market participants.

Second, the two approaches may not end up materially different, depending on the suballocation approaches implemented by EDAM member BAAs. One reason is because EDAM members have the incentive to retain their third-party transmission customers, maximize the transmission available to the market, and offset the annual transmission revenue requirements (ATRR) for their native load. Compensating third-party transmission customers that make their rights available to the EDAM through the suballocation process would help to achieve those three goals, and we expect many EDAM BAAs to do so. Therefore, we do not expect either

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[56] The EDAM tariff states that "For each Settlement Period of the DAM, the CAISO will calculate the contribution of each Balancing Authority Area in the EDAM Area to the Marginal Cost of Congestion at each resource location and intertie in the EDAM Area for each Balancing Authority Area based on the location of the Transmission Constraints in each Balancing Authority Area, EDAM Interties, and constraints enforced outside of the EDAM Area needed to manage that Balancing Authority Area's responsibilities. The CAISO will distribute the Congestion Charge revenue collected from the Transmission Constraints in each Balancing Authority Area in the EDAM Area … to the applicable Balancing Authority Area within which the Congestion occurred. An EDAM Entity will ensure that Congestion revenue allocated to its EDAM Entity Scheduling Coordinator is further allocated by all applicable EDAM Transmission Service Providers as may be detailed in the EDAM Transmission Service Provider tariff and business practices." California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket ER23-2686-000, August 22, 2023, Section 33.11.1.2.

[57] California Independent System Operator, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket ER23-2686-000, August 22, 2023, Section 33.11.1.1

congestion allocation approach to make a significant difference for most utilities in the WECC. Another reason is because most utilities in the WECC conduct their own resource planning and, when feasible, favor locating resources on their own transmission systems to avoid purchasing long-term rights on other utilities' transmission systems. Therefore, most WECC utilities do not have a lot of long-term transmission contracts on other utilities' systems, implying that receiving the congestion revenues according to ownership of transmission rights (the Markets+ approach) will be similar to receiving congestion from within their own BAA (the EDAM approach). However, some load serving entities may find the EDAM approach more flexible for offsetting the loss of short-term wheeling revenues in the market and keeping their native load customers whole.

On the other hand, market participants with a lot of transmission rights outside of their own BAA would likely see a higher congestion revenue under the Markets+ allocation approach compared to a load serving entity that does not have a lot of transmission outside of their BAA.

We do not expect that either market's congestion revenue allocation approach would affect market-wide outcomes, and while the EDAM approach does not explicitly require BAAs to compensate third-party transmission customers, EDAM BAAs are likely to do so. Thus, while we expect largely similar market outcomes for individual BAAs in both the EDAM and Markets+, some differences may arise for individual transmission customers and load-serving entities.

IX. Conclusions

This whitepaper provides a review of several design features of the EDAM and Markets+ proposed day-ahead markets in the WECC. We assess how these design features may impact customer benefits in one market compared to the other, and where available and appropriate provide evidence from other jurisdictions. While some of the design differences between the markets will likely impact market outcomes and overall market efficiency, they are unlikely to have a material effect on customer savings. Customer benefits will be driven by the availability of transmission between market members and the diversity of load and generation resources available in the markets.

The key conclusions for stakeholders in the WECC for each element of market design assessed in this whitepaper are summarized below:

- **Flow-Based vs. Contract Path-Based Optimization.** Both the EDAM and Markets+ will conduct flow-based optimization while respecting their members' contract rights through contract path-based constraints. There is no evidence suggesting that one of the two day-ahead markets will be more or less inhibited by contract path-based constraints, implying that market outcomes are unlikely to materially differ due to contract path constraints.

- **Fast Start Pricing.** Markets+ includes FSP while the EDAM currently includes a limited form of FSP. Analyses conducted by the independent market monitors of MISO, SPP, ISO-NE conclude that FSP has a *de minimus* impact on market prices. Therefore, FSP is unlikely to have a material impact on customer outcomes in Markets+ or the EDAM.
- **Look Ahead and Optimized Real-Time Commitment.** The WEIM includes a four-hour look ahead that enables optimization of commitment decisions for short-cycle time resources in real-time, while the market clearing engine used in the WEIS does not include a similar look ahead and does not perform unit commitment. This will likely enable WEIM to find lower-cost solutions for customers relative to the real-time imbalance market in Markets+.
- **Regional Economic Procurement of Imbalance and Flexibility Reserves.** In both the EDAM and Markets+, members will be able to hold fewer load-following reserves due to the increased regional diversity in renewable generation and load. Each market will procure load-following reserves on a market-wide basis (rather than the BAA-specific basis). This will allow the markets to procure reserves from the most economic resources in the footprint, subject to deliverability constraints, which will likely result in a more efficient, lower-cost outcome for customers. Stakeholders in EDAM and Markets+ should consider extending market-wide procurement to other types of reserves, which would likely provide additional customer cost savings.
- **Seams Optimization.** Markets+ will implement intertie trading at all points along its seam. In the EDAM, intertie trading is only activated if market members elect to do so. The automatic inclusion of intertie trading in Markets+ will allow for more economic transactions at the market seam and create more efficient outcomes for market participants. If all market members in the EDAM enable intertie trading, we would anticipate similar efficiencies.
- **GHG Pricing Mechanisms.** The GHG pricing mechanism used in the EDAM builds off the mechanism currently used in the WEIM for the last ten years, which provides more certainty for stakeholders that it will achieve an efficient market outcome while minimizing leakage. The approach used in Markets+ provides more options for market participants, which implies that outcomes will be heavily dependent on how market members choose to participate.
- **Congestion Revenue Allocation.** In the EDAM and Markets+, congestion revenues will be allocated to market members. In the EDAM, congestion revenues will be allocated to the

participating BAAs, which will decide how to suballocate revenues. In Markets+, congestion revenues will be allocated to entities that control rights on congested constraints. Certain market participants may prefer one approach, depending on their obligations to native load and the location of their long-term transmission contracts. If all EDAM members suballocate congestion revenues to the holders of long-term transmission rights on constrained facilities, the two market designs will likely yield very similar outcomes.

We hope this analysis of market design differences between Markets+ and the EDAM will prove helpful for stakeholders in the WECC, as they make decisions on market participation and work to improve the market designs in their respective markets to improve outcomes for customers.