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NPC and SPPC

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of an Amendment to their 2025-2027 Energy Supply Plan to Participate in the Extended Day-Ahead Market.	Docket No. 25-10___

VOLUME 3 OF 3

TESTIMONY AND TECHNICAL APPENDIX

ANNA MCKENNA

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy

Extended Day-Ahead Market Energy Supply Plan Amendment
Docket No. 25-10___

Prepared Direct Testimony of

Anna McKenna

<u>Introduction of CAISO</u>

1. Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Anna McKenna. I am the Vice President of Market Design & Analysis for the California Independent System Operator ("CAISO"). My business address is 250 Outcropping Way, Folsom, California 95630. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra") (together, "NV Energy").

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF MARKET DESIGN & ANALYSIS?

A. As Vice President of Market Design & Analysis, my responsibilities include the development of market design policy through an open and transparent stakeholder process, the production of short-term forecasts for load, variable energy resources and uncertainty used in operations and in the markets, market performance validation and market issues management, validation of market parameters, market analysis, the development of market strategy, governance process for market design changes, and support for the integration of new

Western Energy Imbalance Market ("WEIM") and Extended Day-Ahead Market ("EDAM") entities. Additionally, I am responsible for California regulatory affairs.

3. Q. WOULD YOU PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE?

A. I completed my Bachelor of Arts with Majors in Industrial Relations and Economics in 1986, and my Honors and Master of Arts in Economics in 1990 and 1992, respectively, all at McGill University in Montreal, Quebec, Canada. I completed my Juris Doctorate at the Washington College of Law, American University in 1999. From 1993 to 1996, I worked as an analyst at the International Food Policy Research Institute in Washington, D.C., modeling and evaluating market linkages in agricultural markets in Western Africa. From 1999 to 2000, I served as an associate at the law firm of Betts and Holt, a small energy boutique firm where we represented municipal utilities in the PJM Interconnection and Canadian Petroleum Producers Association in energy matters before the Federal Energy Regulatory Commission (FERC) and State agencies. From 2000 to 2005, I was an associate at the law firm of Troutman Sanders, LLP in Washington, D.C., where I represented an independent transmission system operator as legal counsel in development of energy markets and market-based congestion management policies and other FERC-related matters. I prepared and filed tariff provisions, and developed and presented alternative policy proposals. I also provided legal representation for electric utilities, electric generators, natural gas pipeline companies, and natural gas pipeline customers. During my time at Troutman Sanders, I served as lead outside counsel for the Midcontinent Independent System Operator on numerous matters related to the development of their markets and transmission tariff provisions. Since 2005, I have been part of CAISO. Until 2020, when I transitioned to my current role, I was inside counsel representing CAISO in numerous regulatory and business matters which included being lead counsel and obtaining FERC approval of the bulk of CAISO's market design changes. My accomplishments over my tenure as counsel include:

- Development of and transition to the market redesign and technology upgrade to implement a full two-day locational marginal pricing market, the development and implementation to the Western Energy Imbalance Market, and market development of day-ahead market enhancements and the extension of the day-ahead market to participants in the Western Energy Imbalance Market;
- Resolution of seams issues with neighboring balancing authority areas related to pricing and modelling of flows and exchanges;
- Resolution of complex congestion revenue rights and other congestion management issues;
- Enhancements of resource start-up and minimized load costs to better reflect fuel-related operating costs in resource bids and optimized dispatch supply resources in CAISO markets; and
- Market rule and program enhancements to reliably integrate renewable resources in CAISO operations and the markets.

In my current role, among other things, I served as the Vice President overseeing the completion of the of EDAM market rules, the filing and regulatory process at FERC, enhancements to the day-ahead market to integrate the Imbalance Reserve Product to better manage uncertainty in the day-ahead market, and related filings to transition the CAISO balancing area into the EDAM, and the resolution of congestion revenue allocation among EDAM areas.

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony, I provide an overview of the design of CAISO's EDAM. I discuss the status of commitments of Western balancing authorities expected to participate in EDAM and the interconnectivity and diversity of resources of that footprint. I also address several of the criteria identified in the Commission's Order in Docket No. 23-10019 including:

- Resiliency of the market to physical threats, such as wildfires;
- Interoperability of CAISO's EDAM market with existing resource planning structures, including the Western Resource Adequacy Program ("WRAP"), NV Energy's integrated resource planning process and energy supply plan, and state resource adequacy requirements;
- Explanations of the market monitoring function and the dispute resolution process;
- Overview of congestion rent and transfer payment allocations;
- Transparency of the CAISO market data: (1) type and location of the data currently available; (2) type and location of the data that will be available after NV Energy joins; (3) how the Commission can access that data; and (4) frequency with which the data will be available to the Commission; and

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

- Greenhouse Gas ("GHG") issues including compliance for states with price-based programs, steps to mitigate "leakage" and emission tracking of resources purchased in the day-ahead market.

5. Q. PLEASE PROVIDE AN OVERVIEW OF CAISO.

A. CAISO was created in September 1996 as a nonprofit public benefit corporation with the passage of California Assembly Bill 1890 that restructured the state's power market. CAISO began grid operations in March 1998. In 2009, following the California energy crisis in 2000-2001, CAISO implemented its Market Redesign and Technology Upgrade reforms, introducing the current day-ahead and real-time market format. CAISO manages the flow of electricity across the high-voltage, long-distance power lines for the grid serving 80 percent of California and a small part of Nevada (the Valley Electric Association). CAISO's peak load of 52,061 MW was recorded on September 6, 2022. The next highest peak was 50,270 MW on July 24, 2006. In addition, through its RC West function, CAISO serves as NERC Reliability Coordinator for 25 BAs and 40 transmission operators including NV Energy. These are illustrated in Figure 1.

Figure 1

RC West Entities

__The Western Energy Imbalance Market__

6. Q. PLEASE DESCRIBE THE DEVELOPMENT AND EVOLUTION OF THE WESTERN ENERGY IMBALANCE MARKET.

A. In late 2011, commissioners from 12 western state regulatory commissions formed a group (the “PUC-EIM Group”) to explore issues related to an energy imbalance market in the West. In March 2012, CAISO provided the PUC-EIM group with a conceptual proposal under which CAISO would provide energy imbalance services through its existing market platform to balancing authorities that choose to participate. By leveraging its market platform, CAISO could offer a solution with less risk and lower costs than could be achieved by creating an entirely new market design and infrastructure. Participants would pay a one-time, up-front fee to cover the cost of CAISO modeling, licensing and other preparatory work. Once the balancing authority's participation in the WEIM was operational, it would pay ongoing fees based on its level of participation consistent with CAISO's grid management charge structure.

In April 2013, PacifiCorp signed an Implementation Agreement to be the first external balancing authority to participate in the CAISO WEIM. Between April 2013 and November 2013, CAISO developed the design for the WEIM and the proposed tariff revisions and agreements through an extensive stakeholder process. On February 28, 2014, CAISO filed proposed tariff changes with FERC. The WEIM went live with PacifiCorp on November 1, 2014. In December 2015, NV Energy became the second balancing authority to join WEIM, followed by others over the years.

Today the WEIM has grown to 22 participants across 11 states providing service to over 80 percent of the Western Interconnection. Black Hills Energy and PowerWatch (formerly BHE Montana) will join WEIM in 2026. The Imperial Irrigation District will join both WEIM and EDAM in 2028.

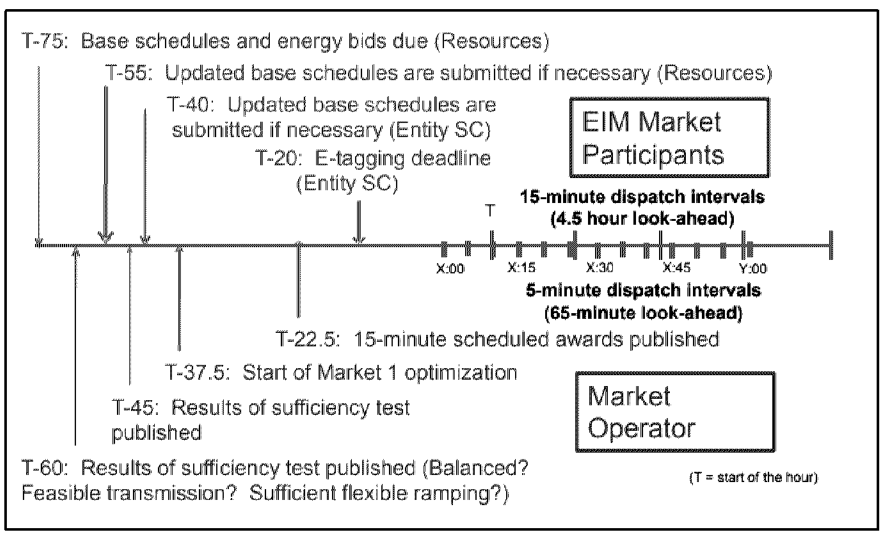
7. Q. PLEASE DESCRIBE THE WEIM.

A. The WEIM consists of a set of rules and procedures under which CAISO makes its real-time market available to other balancing authorities to more efficiently and seamlessly dispatch resources while managing congestion and meeting imbalance energy needs. The WEIM provides a platform under which participants' resources can be economically dispatched throughout the WEIM footprint enabling more efficient management of generation and load imbalances and more effectively supporting reliable operations.

The WEIM's automated dispatch system—using a detailed transmission system model of the market footprint—performs a security-constrained, economic dispatch every 5 and 15 minutes to find the most economical solution to serve load as well as security constrained unit commitment every 15 minutes. Additionally, the WEIM optimizes over a multi-interval look ahead, anticipating system needs and conditions which enables the dispatch and commitment or resources ahead of time to efficiently manage system and congestion. WEIM measures deviations from balanced base schedules submitted by WEIM participants before the operating hour. Figure 2 illustrates the WEIM timeline.

Figure 2

WEIM Timeline



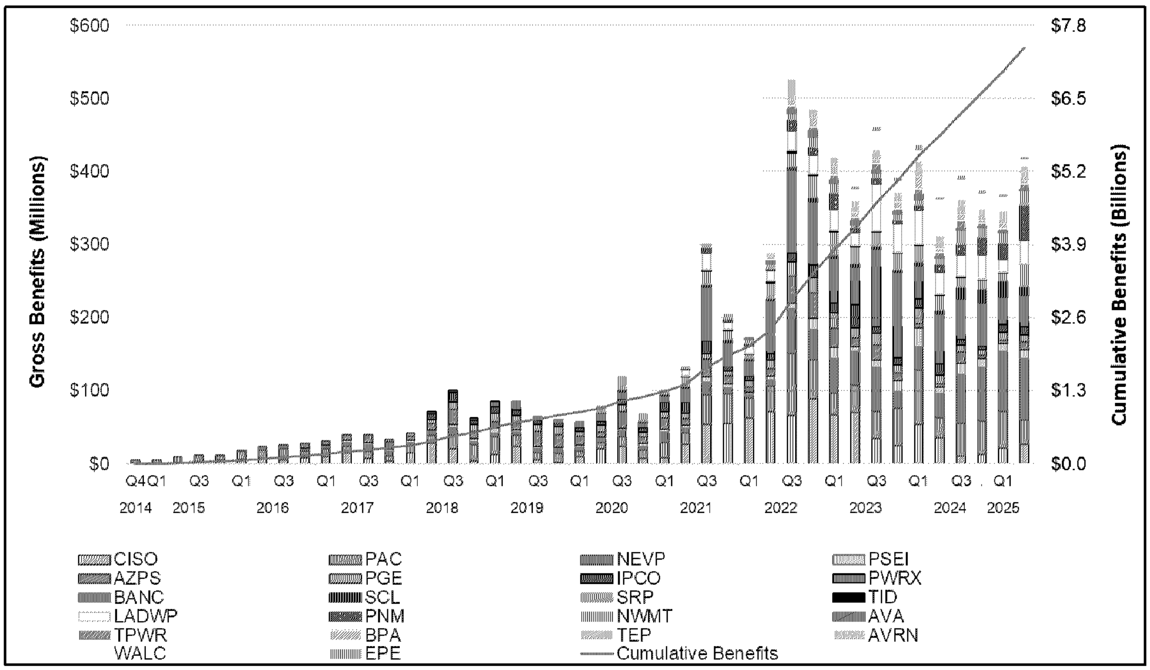
WEIM participation is limited to real-time market operations. Unlike a CAISO participating transmission owner, the WEIM Entity maintains all reliability, planning and transmission control and revenue recovery functions.

8. Q. WHAT ECONOMIC BENEFITS HAS WEIM ACHIEVED FOR CUSTOMERS IN THE WEST?

A. As of the second quarter of 2025, CAISO estimates that the WEIM has produced $7.41 billion in savings for customers of its participating balancing authorities. The distribution of those savings across the years is illustrated in Figure 3.

Figure 3

WEIM Economic Benefits



Since joining the WEIM in 2015, NV Energy customers have accrued an estimated $828 million in savings.

9. Q. HOW HAS WEIM PROVIDED RELIABILITY BENEFITS TO UTILITIES DURING STRESSED SYSTEM CONDITIONS?

A. The WEIM enhances grid reliability by facilitating efficient and optimized energy trading between participating balancing areas on a 15-minute and 5-minute basis, improving the ability to optimally dispatch energy from where it is available to where it is needed every 5 minutes to respond to unexpected grid events and manage transmission congestion. WEIM entities have access to an array of sophisticated tools that enable improved situational awareness and coordination across WEIM balancing areas. The real-time market optimizes transfers of energy among the participating areas seamlessly by balancing supply and demand across the entire footprint considering transmission constraints. The WEIM has a one to four hour look ahead that anticipates future needs and commits or positions resources to be ready to serve those needs within that time horizon, across the entire market footprint. This eliminates the need for bilateral arrangements for transfers and enables reliable grid operations for all participants by moving power from where it is available to where it is needed across the WEIM footprint. The expansive WEIM footprint optimizes the transmission connectivity among the participating areas and is the driver of these reliability benefits across what is now the bulk of the Western interconnection.

Grid operators in the WEIM are provided with increased visibility and enhanced situational awareness of grid conditions, which enables them to more efficiently balance supply and demand, particularly during stressed grid conditions. The value of the WEIM is most evident during stressed grid conditions as it identifies the necessary transfers to meet load across the participating areas, considering the state of the grid across the larger footprint, thereby reducing the need for emergency exchanges. WEIM provides access to a wide pool of supply across the market footprint and considers diverse load requirements. The WEIM spans across a large geographic area with a diversity of weather conditions and non-coincident load requirements. This provides all participants with access to more economic and physically feasible options to better manage the grid conditions.

Over the last decade, we have seen these reliability benefits at play during Western heatwaves and wildfire conditions that jeopardized grid reliability. For example, the Bootleg wildfire in Oregon in July 2021 led to the derate of the Pacific AC Intertie, which significantly limited imports into California and exports to the Northwest. The WEIM was able to leverage supply diversity across the participating balancing areas and quickly redispatched generation across other available transmission paths to support reliability and continue to serve demand where it was needed.

Another example of the reliability value of the diversity of supply in the WEIM and its support of grid resilience is the September 2022 heatwave which gripped California, and during which the CAISO balancing area established its all-time peak demand. The WEIM redispatched available generation across other participating balancing areas – from the Northwest and Desert Southwest – to help support service to load and avoid load shed.

A similar heatwave in the summer of 2023 created stressed grid conditions in Arizona, with severe heat over a prolonged period. During this period, the

WEIM provided real-time access to diverse supply on a 15-minute and 5-minute basis from across the other balancing areas participating in the WEIM, from California and the Northwest. Access to this supply, across critical peak periods of the day when solar supply is reduced, helped the Arizona WEIM entities maintain grid reliability within their balancing areas.

More recently, in January 2024, the Northwest faced challenging grid conditions due to a severe cold weather event. During the storm, supply in the Northwest was limited and conditions were further exacerbated by transmission line outages. The real-time market efficiently redispatched available generation across the 22 interconnected WEIM balancing areas, delivering generation from the Desert Southwest region, from California and other areas to support reliable grid operations under these extreme conditions, while respecting all provided transmission limits.

10. Q. HOW HAS THE WEIM EVOLVED TO ENHANCE RELIABLE OPERATIONS?

A. Through the collaborative stakeholder process, CAISO and participating WEIM entities developed an important enhancement in 2023 that strengthens reliability by enabling the ability to transfer energy more readily during stressed conditions (i.e., the assistance energy transfer product). When a WEIM balancing area has not met its resource sufficiency evaluation, its transfers are limited to the last level of transfers it experienced prior to the failure. The failing entity can still participate in the WEIM, but it is limited. The resource sufficiency evaluations are necessary to ensure participants bring sufficient resources to meet their load and uncertainty to the market so that the

WEIM can then optimize load and supply efficiently, economically, and reliably. The WEIM entities noted that failures of the resource sufficiency evaluation may coincide with times their systems may be most at risk. WEIM entities advocated that accessing additional transfers during these constrained conditions may be critical for reliability and entities should have access at an additional surcharge. The assistance energy transfer product is optional and leverages the WEIM market to support reliability in challenging grid conditions, avoiding the need to trigger emergency energy transfers between balancing areas.

11. Q. DO WEIM AND EDAM ENHANCE THE ABILITY TO RESPOND TO PHYSICAL THREATS SUCH AS WILDFIRES?

A. Yes. As illustrated during the Bootleg wildfire event in 2021 that derated one of the most significant transfer paths in the West, the Pacific AC Intertie, the interconnectivity of the market, increased supply, and security constrained modeled dispatch can move energy quickly to respond to contingencies. The market reduces the risk of a single point of failure, providing access to a geographically and technologically diverse supply and demand that can be delivered across different transmission paths across a robustly interconnected market footprint. The market can also help facilitate flow management across constrained paths by enforcing associated transfer limitations based on the additional information that is available in real-time. EDAM will extend this capability to the day-ahead timeframe, enhancing the available tools to manage transmission derates and loss of generation.

Extended Day-Ahead Market

12. Q. PLEASE PROVIDE AN OVERVIEW OF CAISO'S EXISTING DAY-AHEAD MARKET.

A. CAISO's existing day-ahead market is a financially binding market that clears physically feasible hourly energy demand and supply and procures ancillary services requirements across the 24 hours of the next day. The day-ahead market consists of four steps: (1) bid submission; (2) market power mitigation of the submitted bids to supply energy, ancillary services, and residual unit commitment ("RUC") capacity; (3) the Integrated Forward Market ("IFM"); and (4) the RUC process. In the IFM, participants can submit either economic bids submitted for both supply and demand or price-taker bids referred to as self-schedule. Generation resources offer separate bids to supply energy, ancillary services, and RUC capacity. The RUC process optimizes supply bids against load forecast for each hour of the next day to ensure sufficient resources are committed to serve load reliably the next day. The day-ahead schedules produced by these processes determine the starting point for the real-time market the next day. The real-time market accepts new bids and produces imbalance energy schedules to meet actual load requirements.

Scheduling coordinators for load serving entities ("LSE") submit bids for load in the day-ahead market by 10:00am Pacific Standard Time ("PST") of the day prior to the operating day. Participants can submit bids for supply and demand, including exports, imports, and wheel-through transactions. After bids have been submitted, CAISO conducts a market power mitigation screen that identifies and mitigates potentially uncompetitive supply bids to ensure the market prices that result from the IFM are competitive.

The IFM is a financial market where bid-in supply clears against bid-in load and ancillary service requirements; it co-optimizes energy and ancillary service procurement for each operating hour of the following trading day and minimizes overall procurement costs while respecting transmission constraints and resource constraints, such as minimum run time and start-up time. After the market power mitigation run, CAISO clears supply and demand bids, which include bids mitigated through the market power mitigation process, in the IFM and issues schedules for energy and ancillary services. There are two runs in the IFM. The scheduling run determines the physically feasible resource schedules. The pricing run then produces market-clearing prices for energy (locational marginal prices or "LMPs") and ancillary services.

The final step of the day-ahead market is the RUC, through which capacity is procured to fill any gaps between the physical supply that cleared the IFM and the physical supply needed to meet CAISO's demand forecast. The resulting market awards and schedules are then published by 1:00pm PST the day prior to the operating day. Currently, the existing day-ahead market is operated only within the CAISO balancing area. The EDAM will extend this day-ahead market platform to optimize hourly energy schedules in the day-ahead collectively for CAISO and any WEIM Entity balancing area that chooses to participate voluntarily.

13. Q. HOW WAS EDAM DEVELOPED?

A. WEIM entities expressed interest in participating in a day-ahead market with CAISO on a voluntary basis. Entities recognized that the benefits that have been enjoyed in the WEIM can be enhanced by the ability to optimize load and resources in the day-ahead when there may be a broader range of options than are available in the more limited real-time markets. CAISO facilitated an extensive, open and transparent stakeholder process to consider the design of a day-ahead market that can be extended to WEIM participants. The stakeholder effort extending over a period of three years involved:

- Sixty working group meetings;
- More than 20 workshops, proposal and tariff meetings;
- Over 130 sets of written stakeholder comments;
- Four design proposal iterations; and
- Numerous additional meetings and briefings with stakeholders and regulators.

The EDAM design is memorialized primarily in Section 33 of the CAISO Tariff, has been approved by FERC, and is slated for implementation in May 2026.

14. Q. WHAT ARE THE CORE ELEMENTS OF EDAM?

A. Extending the day-ahead market across the West allows for optimized commitment of diverse generation in the day-ahead timeframe across a robustly interconnected market footprint to serve the next day's forecasted load. It provides incremental economic, reliability, and environmental benefits, while permitting participants and their regulators to retain key responsibilities over resource planning, transmission planning, and reliability operation functions.

EDAM market operations occur primarily across three timeframes: (1) before the day-ahead market, or "pre-market;" (2) within the day-ahead market; and (3) after the day-ahead market. First, in the pre-market timeframe, the EDAM activities center on preparing for the optimization of the day-ahead market by addressing transmission availability, accounting for legacy transmission contracts and transmission ownership rights, and ensuring each balancing authority area has sufficient resources to support its own obligations. Prior to executing the day-ahead market run, each EDAM Entity will be subject to a resource sufficiency evaluation ("RSE") that evaluates supply made available to the day-ahead market against the entity's next-day demand obligations.

Second, in the day-ahead market timeframe, all resources and load in an EDAM balancing authority area will submit an economic bid or self-schedule in the day-ahead market based on their availability and operational circumstances. This differs from the current load and resource participation model in the WEIM, where a base schedule reflects the planned operation of loads and resources in the day-ahead time frame. Through the IFM and RUC processes, the EDAM will optimize the transmission capability and generating resources offered into the day-ahead market to identify efficient resource commitments and energy transfers between EDAM balancing areas to meet scheduled and forecasted load across the footprint.

Resources located outside of an EDAM balancing authority area may fully participate in the day-ahead market if they are pseudo-tied or dynamically scheduled into an EDAM balancing authority area or are otherwise a designated network resource to serve load in an EDAM balancing authority area under the terms of the EDAM Entity's Open Access Transmission Tariff ("OATT"). Other contracted supply located outside of the EDAM area can self-schedule at the interties of non-CAISO balancing authority areas but cannot economically bid, which is consistent with the WEIM today.

Third, after the day-ahead market has run, the market results are published by 1:00pm PST informing market participants of the resulting unit commitments and day-ahead schedules. All day-ahead market schedules are financially binding and will be settled accordingly.

15. Q. HAS THE EDAM TARIFF BEEN APPROVED BY FERC?

A. Yes. CAISO filed the EDAM Tariff along with proposed enhancements to the day-ahead market on August 22, 2023, in FERC Docket No. ER23-2686. In an order issued on December 20, 2023,[1] FERC accepted in part, subject to condition, and rejected in part, CAISO's filing. The only component FERC initially rejected was the EDAM access charge, and it was rejected without prejudice to the submittal of a future filing in which CAISO provided additional support for this element of EDAM. CAISO made that filing in Docket No. ER24-1746 on April 12, 2024. FERC accepted the EDAM access charge in an order issued on June 11, 2024.[2] Accordingly, CAISO has the FERC approvals necessary to commence EDAM operations.

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1 *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210 (2023).
2 *Cal. Indep. Sys. Operator Corp.*, 187 FERC ¶ 61,154 (2024).

In the December 20, 2023 Order, FERC found:

> DAME and EDAM have the potential to yield significant benefits to the voluntary WEIM and EDAM participants. CAISO has demonstrated that its proposal presents a just and reasonable regional solution to expand the benefits of day-ahead market participation to existing WEIM participants and new entrants to both WEIM and EDAM. Moreover, we find that EDAM has the potential to optimize the use of existing transmission and resources across a larger footprint in the West, which will provide economic and reliability benefits to participants. Additionally, by leveraging a larger and more diverse set of resources across the Western Interconnection, we expect that DAME and EDAM will help CAISO and other EDAM participants to manage the impacts of increasing variable energy resources and extreme weather events in the region.[3]

16. Q. WHICH ENTITIES HAVE EXPRESSED INTEREST IN PARTICIPATING IN EDAM?

A. CAISO has executed EDAM Implementation Agreements with: (1) PacifiCorp; (2) Portland General Electric; (3) the Balancing Area of Northern California, which includes the Cities of Redding, Roseville and Shasta Lake, the Modesto Irrigation District, the Sacramento Municipal Utility District, the Trinity Public Utilities District, and the Western Area Power

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[3] *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210 at P 42; *see also PacifiCorp*, 192 FERC ¶ 61,197 (2025) (order accepting PacifiCorp's OATT amendment to participate in EDAM) and *Portland Gen. Elec. Co.* 192 FERC ¶ 61,195 (2025) (order accepting Portland General Electric Company's OATT amendment to participate in EDAM).

Administration–Sierra Nevada Region; (4) the Los Angeles Department of Water and Power; (5) the Imperial Irrigation District, (6) Turlock Irrigation District; and (7) the Public Service Company of New Mexico.

Other Western balancing areas have also publicly indicated intent or interest to participate but have not yet executed an EDAM Implementation Agreement. PowerWatch (formerly BHE Montana) has expressed an interest in joining EDAM after it joins WEIM, currently scheduled for May 2026. Idaho Power Company has announced that it is leaning toward EDAM as its preferred day-ahead market. Additionally, the Arizona Generation & Transmission Cooperative—which serves the majority of retail load in the Western Area Power Administration's Lower Colorado balancing authority area—expressed its interest in joining EDAM.

17. Q. WHEN IS EDAM EXPECTED TO GO-LIVE?

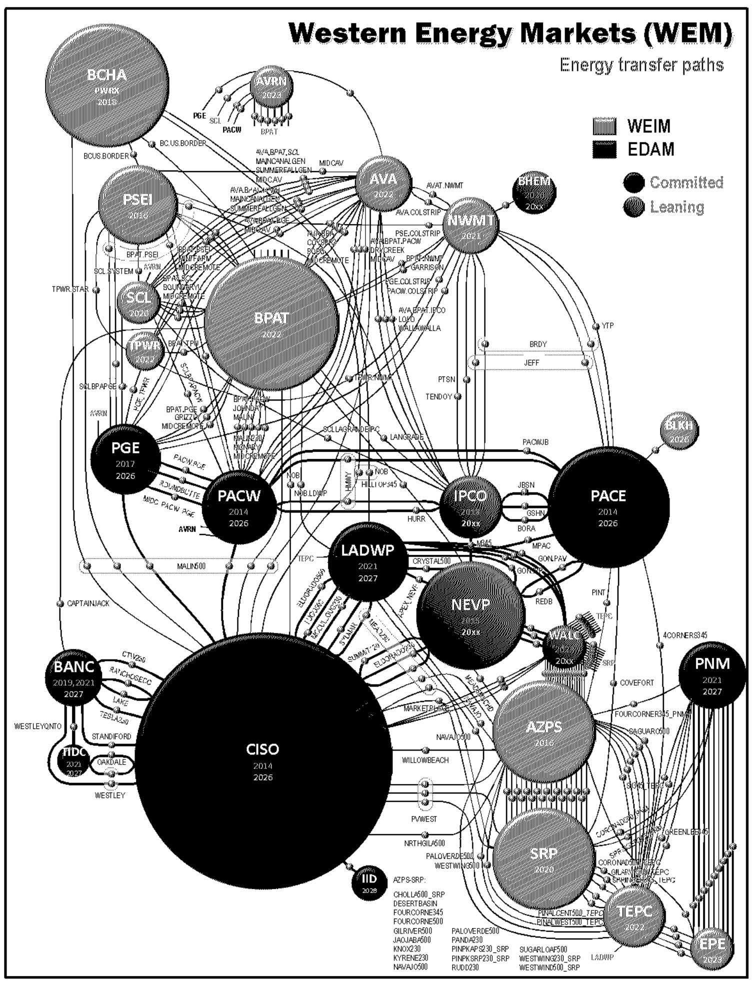
A. The EDAM is targeted to launch in May 2026, with PacifiCorp as the first EDAM Entity. Portland General Electric is expected to commence operations in Fall 2026. The Balancing Authority of Northern California, the Los Angeles Department of Water and Power, Turlock Irrigation District, and the Public Service Company of New Mexico are expected to join in Fall 2027. Imperial Irrigation District, and hopefully NV Energy, would enter EDAM in Fall 2028.

18. Q. PLEASE DESCRIBE THE CONNECTIVITY THAT EXISTS WITH THESE POTENTIAL EDAM PARTICIPANTS.

A. CAISO has significant interconnectivity with NV Energy and other EDAM participants. In addition, the announced EDAM participants with signed implementation agreements have significant interconnectivity with each other. This robust transmission interconnectivity is illustrated in Figure 4 below.

Figure 4

Western Energy Markets (WEM)



The entities which have executed an EDAM Implementation Agreement represent approximately 42 percent of the load in the Western Interconnection. With the addition of NV Energy and the other entities which have indicated their intent or interest in participating in the EDAM, this would represent close to 50 percent of the load in the Western Interconnection. The participation of these entities provides significant and robust transmission interconnectivity across the EDAM footprint, enabling robust and efficient energy transfers between the balancing areas and providing cost savings for the utilities and their consumers.

19. Q. HOW DOES THE EVOLUTION OF THE EDAM AFFECT THE WEIM FOOTPRINT AND CONNECTIVITY?

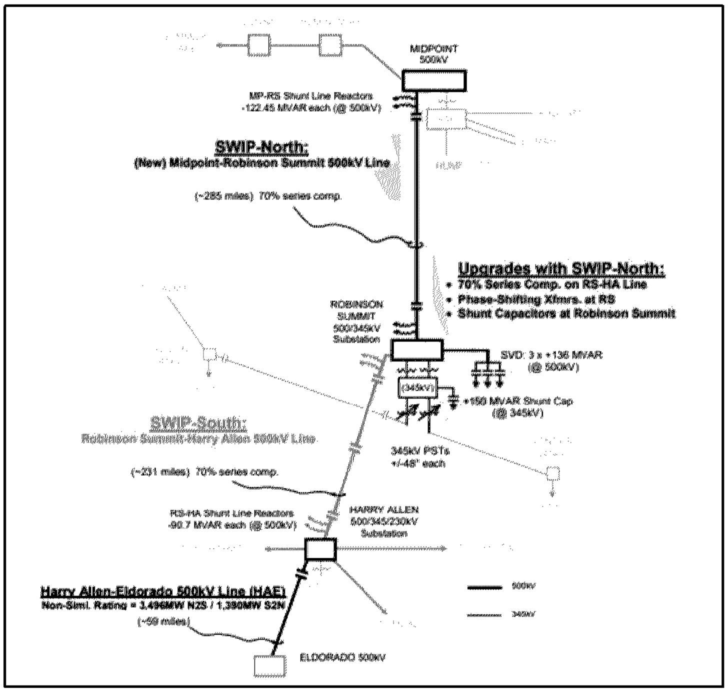
A. Entities can remain in the WEIM without transitioning participation to the EDAM. Therefore, the WEIM will continue to serve as the critical mechanism to economically and reliably optimize the robust diversity of supply and demand over a highly interconnected transmission network. At the start of EDAM, the WEIM footprint will remain the same, except with two additional new WEIM entrants launching participation in May 2026. However, like today, the WEIM will cover less than 10 percent of total energy in the market footprint because entities participating in the WEIM plan for the bulk of their needs through bilateral transactions as they set-up for their day-ahead operations through their individual protocols. Because of this separate and disparate process, these entities enter the WEIM without the benefit of co-optimizing their load, resources and use of transmission. This approach to planning and set-up will also be the case with EDAM. Nevertheless, as long as the WEIM footprint stays together, we can expect the same reliability benefits and the economic benefits that now exceed $7.4 billion. Also, EDAM benefits are expected to be incremental to the WEIM benefits.

20. Q. IS CAISO PARTICIPATING IN ANY INTERREGIONAL PROJECTS THAT WILL ENHANCE THIS INTERCONNECTIVITY AND PROMOTE ADDITIONAL SUPPLY DIVERSITY?

A. Yes. CAISO has entered into a Development Agreement with Great Basin Transmission, LLC ("Great Basin") to facilitate development of the Southwest Intertie Project-North ("SWIP-North"). FERC approved the agreement in Docket No. ER25-543-000 on January 21, 2025. The project consists of: (1) a new 285-mile, 500 kilovolt (kV) transmission line (the SWIP-North Line) that will run from the existing Midpoint substation located near Twin Falls, Idaho to the existing Robinson Summit substation located near Ely, Nevada; (2) expansion of the Midpoint and Robinson substation facilities to accommodate the interconnection and operation of the SWIP-North Line; (3) a new 70-percent series compensation for the SWIP-North Line; and (4) the existing ON Line, a 231-mile, 500 kV transmission line, that runs from the Robinson Summit substation to the Harry Allen substation located near Las Vegas, Nevada. CAISO customers will ultimately fund approximately 77 percent of the total cost of the project through a transmission access charge based on, in part, the transmission revenue requirement to be submitted to the Commission by Great Basin. CAISO's transmission access charge is the combination of the approved transmission revenue requirements of all of CAISO's participating transmission owners. The relationship between SWIP-North, ON Line, and the existing CAISO DesertLink (Harry Allen to El Dorado) Line is shown in Figure 5.

Figure 5

SWIP Project Diagram



WECC has approved a path rating for the SWIP-North Line of 2,070 megawatts (MW) in the north-to-south direction and 1,920 MW in the south-to-north direction. CAISO understands that, in accordance with the Second Amended and Restated Transmission Use and Capacity Exchange Agreement between NV Energy and Great Basin, completion of the SWIP-North Project will trigger a capacity allocation that will result in Great Basin receiving 1,117.5 MW north-to-south and 1,072.5 MW south-to-north on SWIP-North with NV Energy holding the balance.

Importantly, the upgrades for SWIP-North expand the existing capacity on the ON Line. Great Basin Transmission South, LLC, an affiliate of Great Basin, already owns 1,117.5 MW north-to-south and 1,072.5 MW south-to-north capacity on the existing ON Line. Great Basin will become a CAISO Participating Transmission Owner ("PTO") meaning its capacity allocation will be turned over to CAISO for use in the CAISO market for both the SWIP-North and ON Line entitlement rights.

SWIP-North is not the only project in development. CAISO has received FERC approval for a new Subscriber PTO Model to deliver generation from out-of-state resource developers to California without increasing the transmission revenue requirement of the transmission access charge. The transmission project is financed through a FERC-approved subscriber process. The facility is then turned over to the CAISO operational control and is within the CAISO balancing area.

Two Subscriber Participating Transmission Owner projects are underway to accommodate the wind resources in Wyoming (TransWest Express) and New Mexico (SunZia). CAISO received an application from TransWest Express on September 16, 2022, and filed the Applicant Participating Transmission Owner Agreement with FERC on January 13, 2023, in Docket No. ER23-838 and approved by FERC on March 14, 2023. TransWest Express filed the Subscriber Participating Transmission Owner Tariff for TransWest Express with FERC on September 22, 2023, in Docket No. ER23-2917-001, and it was approved on March 12, 2024. On January 24, 2024, CAISO received an application from SunZia to place its high-voltage direct current ("HVDC") transmission facilities in New Mexico and certain transmission rights in Arizona under the CAISO operational control as a Subscriber PTO. The

SunZia application was approved by the CAISO Board of Governors in May 2024 and by FERC on September 4, 2024, under Docket No. ER24-2471-000. TransWest Express consists of a 405-mile, 3,000 MW HVDC transmission line from Wyoming to the Intermountain Power Project ("IPP") in Delta, Utah, and then a 267-mile, 1,500 MW 500 kV AC transmission line from IPP to TWE Crystal and an interconnection to CAISO's Harry Allen to Eldorado 500 kV transmission line. The Project will initially consist of the HVDC line from Wyoming to IPP with 1,500 MW of capacity and the 500 kV AC line from IPP to TWE Crystal and the interconnection to the Harry Allen to Eldorado 500 kV transmission line. TransWest Express expects to be in commercial operation in 2030. Subsequently, the capacity of the HVDC line from Wyoming to IPP will increase to the full 3,000 MW.

SunZia is a 552-mile HVDC bi-pole transmission facility with a limit at the point of interconnection of 3,021 MW of wind generation in New Mexico, with the total generation build out of 3,650 MW. A total of 2,131 MW is currently planned for delivery to California via Pinal Central to the Palo Verde substation using entitlements across Arizona. SunZia expects to be in commercial operation in mid-October 2025.

These projects meet the integrated resource plan projected by the California Public Utilities Commission needed for diversity to meet the load and will bring significant quantities of diverse renewable resources into the CAISO market.

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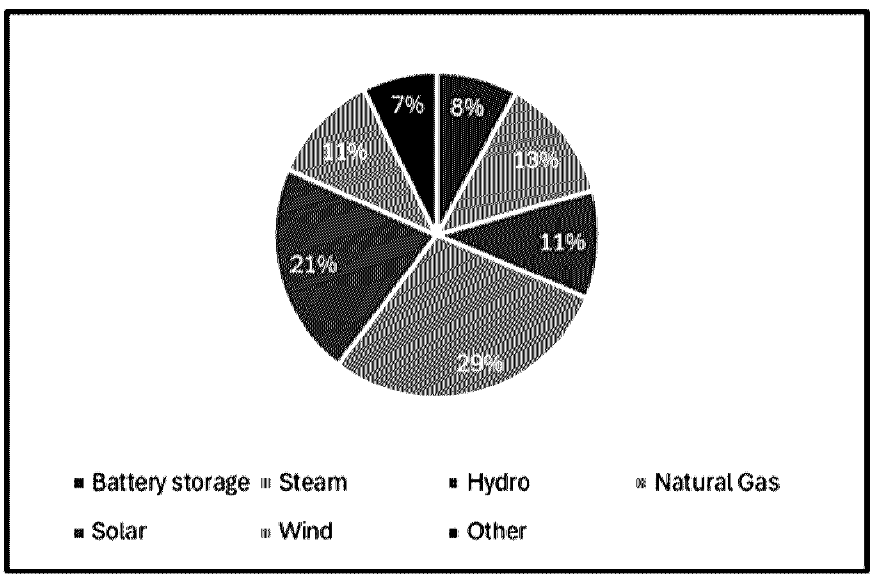
21. Q. DOES THE PROJECTED EDAM FOOTPRINT CONTAIN A DIVERSE SET OF RESOURCES?

A. Yes, the projected EDAM footprint represents a very diverse set of resources. Based on the WECC long term reliability assessment annual study, approximately 160,000 MW of installed generating capacity is located within balancing authority areas that have executed EDAM Implementation Agreements and have expressed a leaning toward the EDAM, including NV Energy.[4] The projected EDAM footprint represents nearly 50 percent of the demand and approximately 50 percent of the installed generating capacity in the Western Interconnection.

Figure 6 illustrates the diversity of the resource fleet in the projected EDAM footprint by generation technology type.

Figure 6

Estimated EDAM Resource Diversity



[4] https://www.wecc.org/program-areas/reliability-planning-performance-analysis/reliability-assessments.

The robust resource diversity composition allows the market to optimally commit and dispatch the least cost generation across different periods of the day to serve demand across the footprint, much as the WEIM has done to date. Solar generation for example, while it represents approximately 21 percent (nearly 34,000 MW) of the installed capacity in the projected EDAM footprint, represents nearly 80 percent of the solar installed capacity in the Western Interconnection. Similarly, wind generation represents approximately 11 percent (over 17,000 MW) of installed capacity of the projected EDAM footprint, which is approximately 45 percent of the installed wind capacity in the Western Interconnection. Natural gas resources, which particularly help provide flexible capacity, represent approximately 29 percent (over 46,000 MW) of the installed generating capacity in the projected EDAM footprint which also represents approximately 55 percent of the total installed natural gas capacity in the Western Interconnection. And for one last comparison, battery storage resources represent approximately 8 percent (nearly 13,000 MW) of the installed capacity in the EDAM footprint, which represents approximately 80 percent of the total battery storage installed capacity in the Western Interconnection.

This robust resource diversity, with a sizable amount of different technology-type resources, will enable the market to efficiently dispatch generation to serve demand cost effectively. The market can dispatch the broad pool of solar generation during the middle of the day, complemented by other types of renewable resources, to serve demand across the interconnected EDAM footprint. In the evening peak demand periods, as solar generation is decreasing output, the market has available a diverse set of generation, including battery storage, to meet the demand across the EDAM footprint supporting reliable operation of the grid and service to load.

Similarly, the load in the projected EDAM footprint represents approximately 50% of the load in the Western interconnection. While some of these balancing authority areas are summer peaking, other balancing authority areas can be considered as dual peaking with similar summer and winter peak loads. This load diversity will allow the EDAM, as it has with the WEIM today, to efficiently utilize and share generation across balancing authority areas and provide cost savings for utilities. When seasonal load in one EDAM balancing authority area peaks, there may be more generating resources available to serve load from other EDAM balancing authority areas where the load does not traditionally peak during that season.

EDAM Market Design

22. Q. PLEASE DESCRIBE THE DIFFERENCES IN THE PARTICIPATION MODEL BETWEEN WEIM AND EDAM.

A. The EDAM, as the name implies, represents an extension of the day-ahead market across balancing areas already participating in the WEIM, the real-time market. Thus, a balancing area participating in EDAM participates in both the day-ahead market and the real-time market. Participation in the WEIM represents participation in only the real-time market.

Participation in EDAM enables the market to efficiently position diverse generating supply through the day-ahead market to serve forecasted load across the footprint. Then, the real-time market may make additional adjustments to this plan and commit additional generation or decommit generation based on the changing load and supply conditions in the market footprint.

As a result of participation in the EDAM, all resources within the balancing area will participate and operate through the market by submitting economic bids or self-schedules. This allows the market to efficiently commit and dispatch a diverse pool of generation to serve demand in the footprint based upon how this generation is economically bid or self-scheduled in the market. This is different from WEIM participation today, which allows for participating and non-participating resources.

Additionally, in EDAM the full network transmission capability is modeled and made available to the market to support generation optimization and delivery across the market footprint and efficient energy transfers between EDAM balancing areas. In the WEIM today, availability of the transmission system to support the optimization is limited and supports only real-time market transactions.

Finally, in EDAM, both day-ahead and real-time market schedules resulting from the market optimization are settled with the appropriate scheduling coordinator and EDAM Entity for the day-ahead and the real-time market horizons. In WEIM, only real-time market transactions are settled and further settlement depends on whether the generation is a participating or a non-participating resource in the market.

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23. Q. IS JOINING EDAM EQUIVALENT TO JOINING CAISO?

A. No. A balancing authority that elects to participate in EDAM will remain responsible for maintaining the reliability of its balancing authority area, including meeting operating reserve and capacity requirements, scheduling, curtailment of the transmission facilities under its operational control, and manually dispatching resources to maintain reliability as is the case today with participation in the WEIM. Functional separation of participants in EDAM will remain similar to the WEIM, with each participating entity retaining its associated functions.

Participation in EDAM does not directly affect transmission planning, interconnection, integrated resource planning, or transmission access. Retaining these functions, along with administration of its Open Access Transmission Tariff (OATT), empowers participating entities to continue their organizational operation as they do today, while at the same time supporting their participation in a multi-balancing authority area day-ahead market. This participation model complements the WEIM and allows for coordinated participation, including a balancing authority area's continued participation only in the WEIM.

Participation in the EDAM does not modify NV Energy's integrated resource planning process or the state resource adequacy program.

<u>EDAM Resource Sufficiency</u>

24. Q. PLEASE DESCRIBE THE EDAM RESOURCE SUFFICIENCY EVALUATION.

A. Similar to the WEIM, CAISO expects balancing areas participating in the day-ahead market to demonstrate they have sufficient supply to meet next-day obligations, balancing and flexibility needs. The EDAM resource sufficiency evaluation ("RSE") embodies this same principle.

Under this structure, before the first run of the day-ahead market, each balancing authority participating in EDAM will be evaluated to determine if its resources offered into the market are sufficient to meet its projected needs in the day-ahead time horizon. Specifically, the EDAM RSE will review the demand obligations and supply options for each balancing area and determine whether there is sufficient supply offered into the market to satisfy the forecasted demand obligations, the forecasted imbalance reserve requirements intended to manage forecast uncertainty, and the forecasted ancillary service obligations. Results of the RSE will be provided to each balancing authority area on an advisory basis to assist the balancing authority in tracking its resource sufficiency prior to the binding run of the RSE at approximately 10:00am PST (i.e., immediately prior to running the day-ahead market).

The EDAM RSE recognizes the unique circumstances of balancing areas in the Western Interconnection. The EDAM does not require that entities enter a common resource adequacy and planning process and leaves it to each balancing authority how they conduct their long-term resource adequacy or resource planning programs. However, the reliability and economic benefits of being in the EDAM are enhanced by having sufficient resources to meet the demand, which then can be optimized across the diverse footprint. These minimum expectations are consistent with how prudent utilities operate their systems today in taking necessary steps to ensure it has sufficient generation to meet its next-day expected conditions. The EDAM resource sufficiency evaluation serves as the common mechanism to ensure near-term horizon day-ahead supply sufficiency without duplicating or supplanting the existing resource adequacy or resource planning programs. The uniform application of the EDAM RSE ensures each balancing authority can meet its own obligations before it engages in transfers with other balancing authorities in the EDAM area through the day-ahead market to reduce the cost of serving load within its system. By requiring each balancing authority area in the EDAM market footprint to demonstrate sufficient forward procured supply bid into the market each day, the EDAM RSE structure encourages entities to plan and to procure so they may have sufficient resources to meet their load. If all entities take such actions, the EDAM will find the least cost solutions for all participants. If entities repeatedly come in short, others will not be able to benefit from the supply of diverse resources, thereby undermining the benefits of EDAM for all. CAISO and market participants designed the EDAM RSE to work in harmony with, and not act as a replacement of, the integrated resource planning process overseen by the state commissions or local regulatory authority, and the WEIM RSE assessments performed in real-time.

25. Q. HOW WILL ENTITIES BE EVALUATED UNDER THE EDAM RSE AND WHAT ARE THE CONSEQUENCES IF THEY FAIL?

A. Under the design of the EDAM RSE, each balancing authority will be evaluated on an individual basis before accessing CAISO's day-ahead market to determine if its own resources offered to the market for optimization are sufficient to meet its forecasted need for energy, imbalance reserves, and ancillary services. Entities that do not cure their deficiencies prior to the binding assessment will be assessed surcharges tailored to the nature of failure.

Building upon the principles of the WEIM RSE, where the RSE tests are uniformly applied to a diverse group of balancing authorities, the EDAM RSE will apply uniformly to produce an hour-by-hour assessment of resource sufficiency, across a 24-hour horizon, for the day-ahead timeframe for each balancing authority area in EDAM. CAISO will perform "advisory" runs of the EDAM RSE and provide the results to each balancing authority every 30 minutes between 6:00am PST and 9:00am PST each day. CAISO will perform the final binding run of the EDAM RSE at approximately 10:00am PST.

To perform the evaluation, the EDAM RSE application will model an EDAM balancing area's entire load and supply on a single bus and perform a unit commitment optimization using all existing CAISO resource models. The optimal function of the EDAM RSE will be set to minimize the total cost as a means to determine the most efficient use of the varying resource types and capabilities made available to EDAM. By using existing market models in each hour of the day-ahead time horizon, the EDAM RSE application will establish the hourly requirements in the upward and downward direction for each balancing authority in the EDAM area across each of the three component parts, energy, imbalance reserves and ancillary services requirements, and will compare each balancing authority's requirements against the same balancing authority's EDAM RSE-eligible supply offered into the market. This supply can include contracted imports delivered to an EDAM balancing area, such as WSPP-Schedule C arrangements which must meet tagging requirements.

A balancing authority in the EDAM area will pass the final binding EDAM RSE if the volume of supply offered into the market meets all the component requirements in each hour of the day-ahead time horizon. Entities that do not satisfy the RSE may be assessed surcharges tailored to the specific circumstances, with *de minimis* failures exempt from surcharge. In recognition of the common demonstration of daily resource sufficiency, the passing EDAM entities will be "pooled" together and evaluated as a single group for purposes of the WEIM real-time market RSE. If a balancing authority in the EDAM area fails to satisfy all component requirements of the EDAM RSE, such entity remains eligible for inclusion in the pool if the market can resolve the insufficiency through supply procured in the IFM. If the market cannot resolve the insufficiency through the IFM, then the entity will not be placed into the pool, and it will be evaluated individually for purposes of the WEIM real-time RSE.

26. Q. WHAT ARE THE COMPONENTS OF THE RESOURCE SUFFICIENCY EVALUATION?

A. The EDAM day-ahead RSE compares that sufficient supply bids, whether economically bid or self-scheduled, have been submitted to the market to meet the EDAM balancing area's next-day obligations: (1) demand forecast; (2) imbalance reserves obligations, which consist of an assessment of load and supply uncertainty; and (3) forecasted ancillary service obligations.

The demand forecast component is the largest component of the RSE and is a representation of the expected next day demand within the EDAM balancing authority area. The second component, imbalance reserves obligations, considers the need for additional flexible generation bids to manage uncertainty that may materialize between the day-ahead and real-time associated with solar and wind generation forecasted output uncertainty as well as load forecast uncertainty for the balancing area. The third component, ancillary service obligations, considers the balancing area's determination of the amount of ancillary service needs across the next day. The day-ahead RSE is conducted for each hour across a 24-hour horizon evaluating the amount of supply bids and the balancing area's next-day obligations.

27. Q. WHAT ARE THE CONSEQUENCES OF FAILING THE RESOURCE SUFFICIENCY EVALUATION?

A. CAISO's Tariff sets forth the framework for the EDAM day-ahead RSE failure surcharge and provides for three types of surcharges: the EDAM RSE on-peak upward failure insufficiency surcharge, the EDAM RSE off-peak upward failure insufficiency surcharge, and the EDAM RSE downward failure insufficiency surcharge. Scheduling coordinators for EDAM entities that fail the EDAM RSE by more than a *de minimis* amount, including failing entities that cured their failure through the IFM, will be allocated the applicable EDAM RSE failure surcharge.

The EDAM RSE upward failure surcharges, in both the on-peak and off-peak periods, are categorized in three tiers based on the magnitude of the insufficiency:

- Tier 1: a *de minimis* RSE failure up to the higher of 10 MW or an amount that is less than or equal to one percent of the balancing authority area's upward imbalance reserve requirement for that hour.
- Tier 2: a RSE failure of a magnitude less than or equal to 50 percent of the EDAM balancing authority area's upward imbalance reserve requirement (but higher than a Tier 1 failure).
- Tier 3: a RSE failure of a magnitude greater than 50 percent of the EDAM balancing authority area's upward imbalance reserve requirement.

The EDAM RSE Downward Failure Insufficiency Surcharge is not tiered but will only be allocated if the failure quantity is greater than 10 MW. If the failure quantity in the downward direction is less than or equal to 10 MW, then there will be no surcharge during the applicable hour given the *de minimis* nature of the failure.

The RSE failure surcharges are intended to incent forward procurement of supply, coordination, and positioning of an EDAM balancing authority area to meet its next day obligations and not depend upon the procurement of supply of its neighbors. Revenue generated by the EDAM RSE failure surcharges will be allocated to the scheduling coordinators for the balancing authorities in the EDAM area that passed the EDAM RSE. Each entity allocated charges for an EDAM RSE failure, or otherwise allocated revenue associated with such surcharges, will distribute the charge (or revenue) in accordance with the provisions of its applicable tariff(s).

The EDAM RSE on-peak upward failure insufficiency surcharge addresses deficiencies during on-peak hours, which present the most severe risk associated with identified resource deficiencies in the day-ahead time horizon. To incentivize all balancing authorities in the EDAM area to demonstrate sufficient supply and flexibility in each of the 16 on-peak hours, the EDAM RSE on-peak upward failure insufficiency surcharge applies in all 16 on-peak hours during the day. This was a consensus decision with stakeholders, as all agreed that identified resource deficiencies during off-peak hours present a lesser degree of risk. Accordingly, the EDAM RSE off-peak upward failure insufficiency surcharge will yield a lower failure surcharge and will apply during the failed hour only. Likewise, the EDAM RSE downward failure surcharge will be allocated to the applicable scheduling coordinator in the failed hour only.

The EDAM RSE upward failure insufficiency surcharges are calculated as the product of three values to reflect: (1) the failure quantity, (2) the applicable surcharge price, and (3) a scaled adder for severe and persistent failures. If an entity has failed the RSE, then CAISO will first determine the failure quantity of the EDAM RSE on-peak upward failure insufficiency surcharge based on the failing entity's highest EDAM RSE hourly upward deficiency quantity during the 16 on-peak hours. Second, CAISO will determine the applicable surcharge price by the applicable trading hub price (e.g., Mid-Columbia or Palo-Verde), for the on-peak hours, and the LMP for the load aggregation point ("LAP") within that balancing authority area for the off-peak hours. For the on-peak hours, trading hubs will be used as they are appropriate price proxies for on-peak failures because they represent the cost the failing entity would bear as it sought additional supply to prevent the insufficiency. Third, the scaled adder is composed of two parts, with the EDAM RSE Failure Multiplier reflecting the severity of the failure and the EDAM RSE failure scaling factor reflecting the persistence of failures. The EDAM RSE failure multiplier reflects the severity of the failures, denoted by the three tiers discussed above. The EDAM RSE failure scaling factor reflects persistence and adds one percent to the EDAM RSE failure multiplier for every additional day during the preceding 30-day period in which the entity had a tier 2 or tier 3 failure in the upward direction. For example, seven failures over the preceding 30 days would increase the EDAM RSE failure multiplier of a tier 2 failure from 1.25 to 1.31. The EDAM RSE on-peak upward failure insufficiency surcharge will also include a credit to account for any of the 16 on-peak hours in which the entity satisfied the EDAM RSE. CAISO will determine the EDAM RSE on-peak upward credit as the product of the highest EDAM RSE hourly upward deficiency quantity and the load-weighted average LMP of the load aggregation point in the balancing area. If the EDAM RSE on-peak credit amount exceeds the surcharge amount, the EDAM RSE on-peak upward failure insufficiency surcharge will be capped at zero.

Like the on-peak surcharge described above, CAISO will calculate the off-peak surcharge as the product of three values to reflect: (1) the failure quantity, (2) the applicable surcharge price, and (3) a scaled adder for severe failures. Unlike the EDAM RSE on-peak upward failure insufficiency surcharge, which applies in each of the 16 on-peak hours, the EDAM RSE off-peak upward failure insufficiency surcharge applies only in the failed hour. As noted above, the off-peak surcharge price for the second component is based on the load-weighted average of the LMP of the LAP within the balancing authority area.

CAISO will calculate the EDAM RSE downward failure insufficiency surcharge as the product of two values to reflect: (1) the failure quantity and (2) the applicable surcharge price. CAISO will determine the failure quantity based on the EDAM RSE hourly downward RSE deficiency quantity during the failed hour, and the applicable surcharge price will be the marginal energy cost of the failing balancing area. We do not expect downward insufficiency to present a challenge across a more geographically diverse EDAM footprint and a scaled adder for severity is not included.

28. Q. PLEASE PROVIDE A DESCRIPTION OF THE IMBALANCE RESERVE PRODUCT.

A. The Day-Ahead Market Enhancements ("DAME") proposal approved by FERC at the same time as EDAM contained two new day-ahead market bi-directional products: (1) Imbalance Reserves and (2) Reliability Capacity. Imbalance Reserves is a flexible reserve product designed to address uncertainty in the net load (gross load minus variable energy resource generation) forecast between the day-ahead market and the real-time market, and to address real-time ramping needs not covered by hourly day-ahead market schedules. Imbalance Reserves will ensure the IFM schedules sufficient dispatch capability to meet net load imbalances between the day-ahead and real-time markets. A resource receiving an Imbalance Reserves award must be capable of adjusting their energy output on a 15-minute basis and must submit economic energy bids to the real-time market for its awarded capacity range.

Imbalance Reserves procurement will be co-optimized with the procurement of energy and ancillary services within the IFM. This will improve unit commitment, enhance market efficiency, improve the market's ability to meet real-time operational needs effectively across the market footprint, and increase the feasibility of exports scheduled in the day-ahead. It will also support the EDAM RSE by ensuring that each participating balancing authority area demonstrates it has procured sufficient capacity to manage load and supply uncertainty and meet operational flexibility needs. Imbalance Reserves are therefore a key element of EDAM's ability to optimize resources and maintain reliability across a multi-balancing authority area footprint.

CAISO will set the procurement targets for Imbalance Reserves Up and Imbalance Reserves Down based on the historical uncertainty in the day-ahead load, solar, and wind forecasts. This ensures the market procures flexible capacity that sits above and below the cleared day-ahead energy schedules. Initially, CAISO will set the uncertainty range at the 97.5th percentile and

2.5th percentile levels of forecast error, respectively, which will cover 95 percent of the historical range of uncertainty.

To procure the product, suppliers will submit separate price/quantity bids for Imbalance Reserves Up and Down that are subject to a $55/MWh offer cap. The market will procure Imbalance Reserves using a stepped demand curve, with each step designed to reflect the product's operational value. This mechanism allows the market to procure less than the full requirement if the cost exceeds the cap. The demand curve is also capped at $55/MWh.

CAISO will procure Imbalance Reserves on a nodal basis, using deployment scenarios to assess the deliverability of reserve awards, similar to those CAISO currently uses to procure the Flexible Ramping Product ("FRP") in the WEIM. The design includes configurable parameters, including a tunable "deployment factor" that controls what percentage of Imbalance Reserve awards must be deliverable, and the ability to activate or deactivate specific transmission constraints in the deployment scenarios. This flexibility allows the market operator (i.e., CAISO) to balance operational accuracy with computational efficiency and respond to observed market performance.

Because Imbalance Reserves are priced at a locational level and can affect congestion and energy prices, CAISO will apply local market power mitigation to Imbalance Reserve Up bids. Bids will be mitigated to the higher of the competitive locational price or a $55/MWh default bid to prevent suppliers from exercising local market power in constrained areas.

The deployment factor will determine how much of the Imbalance Reserves procured would have to be feasible in the scenario. This will ensure the optimization still aims to procure the minimum required quantity of Imbalance Reserves but will allow the optimization to procure a certain proportion that is not deliverable. The deployment factor for both up and down deployment scenarios will be established through the public and transparent stakeholder process on parameter validation currently underway. The actual values will be reflected in the business practice manuals that are open to all and are subject to a change management process that requires notice and a comment period before changing the parameters.

Resources will be subject to unavailability charges if they are unavailable to provide their day-ahead Imbalance Reserves award. The Imbalance Reserve product will go into effect with the launch of EDAM in May 2026.

29. Q. PLEASE PROVIDE A DESCRIPTION OF THE RELIABILITY CAPACITY PRODUCT.

A. The Reliability Capacity product will be procured in the RUC process to meet positive or negative differences between cleared physical supply in the IFM and the day-ahead net load forecast. While the current RUC process addresses this gap only in the upward direction, in the enhanced day-ahead market framework, there will be a bi-directional Reliability Capacity product.

Reliability Capacity Up replaces the existing RUC capacity product, covering situations where the IFM clears less physical supply than the forecast. Reliability Capacity Down is an entirely new feature that allows RUC to procure downward dispatch capability to address potential oversupply conditions if the IFM clears more physical supply than the forecast.

Suppliers can submit separate bids for Reliability Capacity Up and Down, each subject to a $250/MWh cap. A new market power mitigation pass will run before RUC to assess and mitigate Reliability Capacity Up bids. Awards are settled at the product's locational marginal price. Resources that receive Reliability Capacity Up or Down awards are obligated to submit economic energy bids in the real-time market for the quantity awarded.

Reliability Capacity differs from Imbalance Reserves in purpose and timing. While Imbalance Reserves are procured within the IFM to manage forecast uncertainty and ramping needs, Reliability Capacity is procured after the IFM to ensure that overall cleared supply aligns with the day-ahead load forecast. It addresses system-level supply-demand imbalances rather than forecast uncertainty. Together, these complementary products support a more reliable and efficient day-ahead market framework. The Reliability Capacity product will go into effect with the launch of EDAM in May 2026.

30. Q. WILL EDAM RETAIN THE CONCEPT OF ASSISTANCE ENERGY TRANSFERS?

A. Yes. WEIM assistance energy transfers will continue to be available as a tool to cure real-time insufficiency. Section 29.34(m) of CAISO's Tariff "freezes" transfers into a WEIM Entity that fails the real-time RSE. In Docket No. ER23-1534, CAISO proposed and FERC approved a means for a balancing area to voluntarily elect to receive assistance energy transfers through the

WEIM, rather than freezing transfers for a WEIM Entity failing the RSE, for an additional cost called the EIM assistance energy transfer surcharge. Revenues from this surcharge are allocated to all of the other balancing authority areas in the EIM area that have net exports and passed the upward capacity and flexibility tests in the RSE. The surcharge is set at the level of CAISO's bid cap at either $1,000/MWh or $2,000/MWh, depending on the prevailing system conditions, multiplied by a megawatt-hour quantity that equals the lower of: (1) the quantity of the upward capacity test or the upward flexibility test insufficiency for the EIM balancing authority area, whichever is higher or (2) the quantity of net EIM transfers into an EIM balancing authority area, excluding base transfers identified on all after-the-fact E-Tags. Revenue from the assistance energy transfers program is allocated to the entities that passed the RSE and are supplying the assistance energy.

assistance energy transfers serve as a useful insurance policy for balancing authority areas experiencing unexpected or extreme events. Recently CAISO filed at FERC to make the assistance energy transfers program a permanent market feature in Docket No. ER25-3491.

<u>EDAM – Transmission Availability</u>

31. Q. PLEASE DESCRIBE HOW TRANSMISSION IS MADE AVAILABLE IN EDAM.

A. The EDAM design maximizes the transmission made available to the market to support efficient transfers within and between participating balancing authority areas, while respecting existing transmission rights. EDAM harmonizes the OATT framework with the organized market where all transmission is available for optimization. A participating balancing authority area will provide information to CAISO regarding any applicable transfer constraints and the amount of transmission capacity available prior to the start of the day-ahead market.

CAISO will include the transmission facilities of an EDAM balancing area in the full network model that is to be used in clearing the market. This includes the modeling of any transmission limits or transmission constraints across the internal transmission network of the participating balancing area. The modeling of the full transmission system will enable the market to optimize delivery of energy across the interconnected transmission systems of the participating EDAM balancing areas supporting efficient market transfers and supporting the exercise of transmission rights within each balancing area.

Transmission capability at interties or interfaces between EDAM balancing areas is also made available to support energy transfers between these balancing areas and derive the benefits from optimized resource commitment and dispatch across a broad market footprint. This transmission capability at EDAM interties is made available to support market optimization in different ways both by transmission customers and the transmission service provider within the balancing area. Each EDAM Entity communicates to CAISO the total transmission capability, the transfer limit, that is available at the interties between EDAM balancing areas.

First, transmission capability across EDAM interties that supports delivery of owned or contracted resources are offered into the market and available to support the day-ahead RSE will establish transfers at the particular intertie between the EDAM balancing areas. This consists of firm or conditional firm priority point-to-point or network integration transmission service reserved under the respective OATTs of the EDAM Entities. As an example, to the extent generation is contracted in an EDAM balancing area to serve load in an adjacent EDAM balancing area, the firm transmission supporting that delivery across the specific EDAM intertie and supporting the RSE would be made available to support EDAM transfers at that particular intertie location.

Second, to the extent a transmission customer holds firm or conditional firm priority transmission rights at an EDAM intertie location and these transmission rights are not already made available as supporting the RSE or otherwise by the transmission customer, the transmission customer could elect to release that transmission capacity to the market prior to the day-ahead market operations (by 9:00am PST). The transmission customer in this instance commits to not exercise or utilize that transmission in the day-ahead or real-time markets for the period for which it is released, providing certainty of availability to the market for supporting market optimization. In return, the transmission customer releasing the transmission will receive a direct settlement from CAISO for any transfer revenue associated with the transmission rights that may accrue at the particular intertie during the period that the transmission is released to the market.

To the extent a transmission customer holding firm or conditional firm priority transmission rights does not schedule the use of their transmission rights by the time of the day-ahead market run at 10:00am PST, or otherwise the transmission capacity is not made available via the methods described above, it will be included in the establishment of transfer limits in the day-ahead market supporting efficient market transfers. Any transfer revenue that may be collected as a result of scheduling limits on the intertie associated with this transmission capacity will be allocated to the EDAM Entity to sub-allocate under the terms of their tariff.

The third method for transmission being made available at EDAM interties to support efficient market transfers is through the transmission service provider. To the extent there is available and unsold firm Available Transfer Capability (ATC) at the EDAM intertie, the EDAM transmission service provider makes this transmission capability available for supporting optimization and efficient market transfers. During the day-ahead market run process, from 10:00am PST to 1:00pm PST, the EDAM transmission service provider will pause sales of transmission service while the market is performing its function based on the transmission capability made available to the market. Following the finalization of the day-ahead market run at 1:00pm PST and publication of market results, the EDAM transmission service providers will resume sales of transmission capacity under the terms of their OATT. A transmission customer whose rights may have been released as ATC and optimized to support EDAM transfers at an intertie location may nonetheless submit a schedule exercising its rights after the close of the day-ahead market.

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<u>Preservation of OATT Rights and WRAP Interoperability</u>

32. Q. PLEASE EXPLAIN HOW EDAM ACCOMMODATES INTRA-DAY OATT SCHEDULING RIGHTS.

A. The EDAM enables and facilitates the exercise of firm and conditional firm priority point-to-point and network integration transmission service rights reserved under the transmission service provider tariff. These transmission rights will be registered with CAISO, as the market operator, to enable the exercise of these rights in the market through submission of a balanced source/sink self-schedule in the day-ahead market and/or in the real-time market. Entities can exercise these transmission rights through the submission of a self-schedule, and the market will recognize the priority of these rights and ensure they are honored as reservations of rights under the EDAM transmission service provider tariff.

To the extent these transmission rights are not exercised in the day-ahead market through the submission of a self-schedule associated with the registered transmission rights, the transmission customer will retain the ability to exercise these in the real-time market timeframe. CAISO will work with EDAM transmission service providers to accommodate balanced intra-day schedule changes associated with the exercise of specific firm transmission service rights in real-time. These firm transmission service rights include firm point-to-point, conditional firm point-to-point, and Network Integrated Transmission Service ("NITS").

EDAM recognizes existing transmission rights and legacy transmission contracts by providing three different avenues for customers to utilize those rights prior to the day-ahead market: (1) a transmission customer may use its rights for its own purpose by submitting a balanced self-schedule associated with registered transmission rights into the day-ahead market; (2) the transmission customer with firm point-to-point rights of a month or longer may elect to release its rights to the market for optimization and, in exchange, be eligible to receive an allocation of transfer revenues (to the extent that such revenues accrue across an interface); and (3) a transmission customer may choose neither to self-schedule nor release its transmission rights. Under the latter scenario, the capacity will be made available to the day-ahead market for optimization; however, the transmission customer retains its right to submit later an intra-day self-schedule associated with those rights.

Under the approved EDAM framework, CAISO will prioritize intra-day scheduling changes on firm transmission service equal with cleared day-ahead schedules. However, if directed by an EDAM transmission service provider, CAISO will grant some intra-day self-schedules market clearing priority in the real-time market over other real-time and day-ahead schedules. CAISO explained to FERC that this provision is aimed primarily to facilitate interoperability with the WRAP.[5] To the extent that there is a resulting market infeasibility associated with accommodating an intra-day self-schedule exercising its firm transmission rights, CAISO will defer to the EDAM Entity to inform the market operator (i.e., CAISO) on how to resolve this infeasibility between competing schedules.

[5] CAISO EDAM Order, 185 FERC ¶ 61,210 at P 313.

Accordingly, EDAM Entity firm transmission customers are not required to submit their self-schedules any earlier than under the *pro forma* OATT, and EDAM will attempt to accommodate any intra-day schedule changes. The market will also afford these schedules the market clearing priority as described above in order to seek to accommodate these intra-day schedule changes exercising firm transmission rights. Specifically, EDAM will attempt to accommodate any intra-day schedule changes via redispatch to address potential infeasibilities. If this is not possible, the transmission service provider could take action to mitigate an infeasibility if all schedules, including those submitted after the 10:00am PST scheduling deadline, cannot be accommodated.

Recognizing the need to allow flexibility for EDAM Entities to accommodate the unique circumstances around certain physical assets and/or contractual rights, CAISO's Tariff also gives the EDAM Entity discretion to hold back (i.e., "carve out") certain transmission from the market. CAISO referred to this in its EDAM filing as the ability to carve out certain transmission and explained that it expected such carve outs to be "rare" because the EDAM design depends heavily on making transmission capacity available to the market to reach efficient outcomes. More frequent or extensive transmission carveouts would create inefficiencies that would limit the benefits of EDAM to ratepayers. Determining the nature and extent of transmission carveouts is the transmission service provider's responsibility established under its tariff.

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33. Q. WHAT MECHANISM WILL CAISO EMPLOY TO PROTECT THESE EXISTING FIRM RIGHTS?

A. For properly qualified rights with notification, CAISO will provide a market clearing priority above cleared day-ahead EDAM transfer schedules on an EDAM transmission service provider system and, if redispatch or other actions by the host EDAM balancing authority area are unable to resolve the infeasibility in a timely manner, cleared day-ahead EDAM transfer schedules will be adjusted to make room for the schedules associated with the specific exercise of the qualified rights after the close of the day-ahead market.

With respect to which OATT rights exercised after the close of the day-ahead market, without condition, CAISO expects that the associated contract reference number ("CRN") submitted for registered transmission rights would be configured based on EDAM transmission service provider instruction to designate eligibility for the higher priority when the schedule is submitted after the close of the day-ahead market. Once the CRN has been configured in CAISO's systems, there is no additional test and CAISO does not have subsequent discretion to ignore the requested schedule change, provided CAISO has been properly notified of the updated schedule.

The first step will be to configure a CRN associated with a registered firm transmission service right as eligible for a higher scheduling priority in the real-time market and associated with a transfer system resource, as indicated by the transmission service provider. Once the CRN is appropriately configured, CAISO anticipates receiving any associated schedule changes after the close of the day-ahead market from the EDAM balancing area by T-

75 to align with its administration of EDAM legacy contracts and the submission of schedule changes, i.e., prior to the hour-ahead scheduling process. This schedule change before the hour-ahead scheduling process will fully account for the change in the real-time market and mitigate the potential for redispatch in the real-time market. After T-75 and up until T-40, the schedule change would be accounted for in the real-time market through the submission of a pre-hour schedule change submitted by the EDAM balancing area. This submission can be updated through the real-time market by the EDAM balancing area. These subsequent schedule changes after the real-time market runs, depending on the timing of the change, may be reflected in the 15-minute market solution, but otherwise would be accommodated as an operational adjustment, i.e., instructed imbalance energy, outside of the market clearing of the real-time market.

34. Q. IS EDAM INTEROPERABLE WITH WRAP?

A. Yes, the EDAM market design is interoperable with WRAP and enables WRAP members to deliver generation within or across the EDAM market footprint to meet their resource adequacy contractual obligations as well as meeting obligations in non-EDAM balancing areas.

Generation owned or contracted by an EDAM Entity to meet seasonal WRAP obligations can be offered into the day-ahead and real-time market to meet the EDAM balancing area RSE. The market will seek to optimize this offered supply and may commit or dispatch this generation. Similarly, to the extent that generation within an EDAM balancing area is owned or contracted by a WRAP participant located in a non-EDAM balancing area, this generation can be delivered to serve load of the WRAP participant through the submission of balanced self-schedules into the day-ahead and real-time market exercising its firm transmission rights.

A WRAP participant located in the EDAM market footprint can also meet its WRAP obligations in the operational timeframe. WRAP participants will be notified of their holdback or deficit requirements by 6:00am PST in the pre-schedule day (day prior to the operating day), which is ahead of the EDAM day-ahead market bid submission deadline at 10:00am PST. A participant which is deficit under the WRAP operational program may secure additional supply from other WRAP members or otherwise bilaterally contract for additional capacity, and this generation can be offered into the day-ahead market by 10:00am PST to meet the EDAM balancing area RSE. To the extent the WRAP participant in an EDAM area has a holdback requirement, it can elect not to submit a bid into the day-ahead market. Similarly, to the extent the WRAP participant in an EDAM area provides generation to a non-EDAM WRAP participant, it can do so in the operational timeframe and can submit a self-schedule into the market to export the generation to the non-EDAM balancing area.

WRAP participants can exercise their firm transmission rights to support WRAP activities within the EDAM market footprint. With respect to EDAM transmission service provider systems, a transmission customer may exercise its firm OATT transmission rights. These transmission rights may be internal to the balancing area, to or between EDAM balancing areas, to export generation to a non-EDAM balancing area or to wheel across the EDAM balancing area to a non-EDAM balancing area. The exercise of these transmission rights will be afforded a priority across an EDAM transmission service provider system consistent with its OATT without impacting the priority afforded the exercise of the OATT rights on other EDAM transmission systems. To the extent the transmission customer wanted to exercise its OATT rights across multiple EDAM transmission systems, its day-ahead or real-time market self-schedule would need to exercise the OATT rights across all of those systems in order to receive the available market scheduling priority across the full path. To the extent those rights are not exercised across the full path, the schedule would not be afforded the priority commensurate with exercise of the OATT rights as supported by CAISO's Tariff.

FERC concluded in its Order on CAISO's EDAM Tariff filing that the EDAM methodology of respecting firm OATT transmission rights accommodated the requirements of WRAP. Specifically, FERC stated:

> We agree that CAISO's proposed framework is compatible with WRAP. As discussed above, EDAM Entities will be able to notify CAISO what contract reference numbers are associated with WRAP, thereby indicating that a firm transmission customer's intra-day schedule should be afforded a higher priority than EDAM transfers. Once CAISO has been notified, it will give the schedule a real-time market clearing priority above cleared day-ahead EDAM transfer schedules without being subjected to a further test or exercise of discretion. Further, we find that the proposed EDAM provisions preserve the rights of firm transmission customers

> under an EDAM Entity's OATT and should therefore be compatible with WRAP participation. We also note CAISO's commitment to continue working with stakeholders to ensure that EDAM is compatible with WRAP participation.[6]

The EDAM design was established thoughtfully with market participants to support interoperability with WRAP and any other resource adequacy or resource planning programs in the West to support robust market participation.

<u>EDAM Congestion Rent and Transfer Payment Allocations</u>

35. Q. PLEASE DESCRIBE THE DIFFERENCES BETWEEN CONGESTION RENTS AND TRANSFER REVENUES.

A. CAISO models internal transmission constraints, internal transmission limits, and transmission transfer limits in the WEIM today, and will continue to do so in EDAM. If these internal transmission limitations or constraints are reached, the market will seek to commit generation in day-ahead or redispatch generation in the real-time market around the constraints or limitations. The marginal cost of congestion accounts for differences between the incremental cost to serve demand at different pricing locations as a result of internal transmission system constraint or limitations, whether generation or load locations, and CAISO settles these differences in payments and charges as congestion revenues. CAISO, as market operator, is revenue neutral and allocates these congestion revenues among participating balancing areas who further sub-allocate these under the terms of their tariffs.

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6 *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210 at P 313 (2023).

Transfer revenue, on the other hand, accrues as a result of scheduling limits being reached at transfer locations (interties) between participating balancing areas. The transmission capability across interties may have limitations due to the amount of transmission capability made available to the market across these transfer interfaces which sets a scheduling limit for the market to respect. When a scheduling limit is reached at a transfer location, the market will seek to commit and redispatch generation across the market footprint to manage this scheduling limit. This may create a price difference in the marginal energy component of the locational marginal prices between the two balancing areas. This price difference is referred to as transfer revenue and CAISO, as market operator, allocates these revenues to the participating balancing areas who further sub-allocate these under the terms of their tariffs.

In the WEIM today, CAISO settles the congestion and transfer revenue through one charge code on a net basis where the revenues accrued are offset by incurred congestion costs. This calculation accounts for congestion revenue accrued due to binding internal transmission limits and constraints as well as binding scheduling limits at transfer locations (interties) between participating balancing areas. With the implementation of EDAM, CAISO will separate settlement of congestion and transfer revenue into two distinct charge codes and processes.

36. Q. HOW DOES CAISO PROPOSE TO ALLOCATE TRANSFER REVENUE?

A. Transfer revenue which is collected by CAISO due to scheduling limits at interfaces (interties) between two EDAM balancing areas will be shared equally (50/50) between the two affected EDAM Entities. EDAM balancing areas can mutually agree to a different allocation percentage at an interface based on pre-existing arrangements and would inform CAISO of such an arrangement to facilitate settlement. The EDAM Entities can sub-allocate the received transfer revenue through the terms of its tariff. The EDAM Entities can mutually agree to an allocation share other than an equal 50/50 basis for transfer revenue at discrete interties, and CAISO will adjust the allocation share as indicated by these EDAM Entities.

37. Q. HOW DOES CAISO PROPOSE TO ALLOCATE CONGESTION REVENUE?

A. As initially approved by FERC, the EDAM design allocated congestion revenues associated with an internal transmission constraint to the balancing area where the constraint is located, including congestion revenues associated with parallel flows that may have accrued in an adjacent EDAM to the extent that the transmission constraint has a flow impact on schedules in the adjacent area.

CAISO subsequently initiated an expedited stakeholder process to evaluate this element of EDAM design informed by stakeholder input. CAISO recently proposed a change to congestion revenue allocation for day-one implementation of EDAM aimed at supporting transmission customers exercising their firm OATT transmission rights in delivering power without facing congestion cost risks they cannot effectively hedge.

FERC approved this enhancement on August 29, 2025, in FERC Docket No. ER25-2637.[7] Accordingly, congestion revenues will be allocated as follows:

- **Internal Congestion Revenue**: An EDAM balancing authority area will continue to be allocated internal day-ahead congestion revenues collected from binding transmission constraints within its BAA.
- **Parallel Flow Congestion Revenues**: CAISO will allocate a portion of day-ahead congestion revenues associated with parallel flows to the EDAM balancing authority area where the congestion revenues are collected, not only to where the transmission constraint is located. The amount allocated will be commensurate with the parallel flow related congestion costs of balanced self-schedules associated with eligible firm point-to-point, including conditional firm, and network integration transmission service transmission rights under the OATT, defined by registered CRNs in the CAISO Masterfile. These revenues will be further sub-allocated to transmission customers by the EDAM Entity under the terms of its OATT. This process does not apply to the CAISO balancing area.
- **Remaining Parallel Flow Congestion Revenues**: CAISO will allocate any remaining day-ahead congestion revenues associated with parallel flows (*i.e.*, unrelated to balanced self-schedules using firm OATT rights) to the EDAM balancing area where the transmission constraint is located.

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[7] *Cal. Indep. Sys. Operator Corp.*, 192 FERC ¶ 61,196 (2025).

38. Q. WHEN DOES CAISO EXPECT TO COMMENCE THE NEXT ITERATION OF CONGESTION RENT STAKEHOLDER PROCESS?

A. CAISO will monitor the performance and impacts of the congestion revenue allocation approach and will initiate the next phase of stakeholder processes in the fall of 2025, ahead of EDAM's launch in 2026. Initial focus will be on: (1) an enhancement to enable allocation of congestion revenues associated with parallel flow that does not depend on the submission of self-schedules associated with registered eligible firm OATT transmission rights and (2) developing a means for the CAISO balancing area to be allocated congestion revenues associated with parallel flows, resulting from a binding constraint in a neighboring EDAM balancing area.

CAISO has proposed the following activities and timelines to support continued engagement:

- Stakeholder working groups launching in the fourth quarter of 2025 prior to EDAM go-live. The working groups would evaluate near-term enhancements and a focus on long-term design, evaluating a spectrum of alternatives and consideration of long-term design principles.
- Stakeholder process lasting 12 to 24 months to evaluate long-term design. By the conclusion of this stakeholder process, CAISO will present a formal proposal to the governing entity for consideration. CAISO will provide quarterly updates to the WEM Governing Body and the CAISO Board of Governors on the status of the initiative, implementation timelines associated with designs considered, and reporting on market performance and data related to congestion within the EDAM footprint.

- Implementation in third year of EDAM operations. To the extent a proposal is approved, CAISO would file the supportive tariff revisions and strive to implement the design within the third year of EDAM operations, considering the structure and complexity of the approved design.

<u>EDAM Transmission Access Charge</u>

39. Q. PLEASE DESCRIBE THE EDAM TRANSMISSION ACCESS CHARGE.

A. The EDAM design also provides framework for historical transmission revenue recovery by EDAM transmission service providers reflecting the potential for reduced transmission sales. To avoid unintended cost shifts from beneficiaries of broader participation in EDAM to existing customers of an EDAM transmission service provider, CAISO proposed and FERC accepted the EDAM access charge design. The EDAM access charge will provide EDAM transmission service providers an opportunity to recover transmission revenues comparable to their historical cost recovery prior to their participation in EDAM. The EDAM access charge allows transmission service providers to recover three components:

(1) Historical transmission revenues from sales of short-term firm and non-firm transmission products of a month or less duration under the transmission service provider's tariff, and for historical wheeling access charge revenues for CAISO transmission owners;

(2) A portion of revenues associated with new approved transmission builds (i.e., network upgrade costs) that increase the transfer capability between EDAM balancing areas based on the proportional ratio of

historical short-term sales to the overall historical transmission revenues; and

(3) Revenues for use of the transmission system when wheeling through transfer volumes in an EDAM balancing area are greater than total import and export transfer volumes for the balancing area.

Recovery of these revenues will compensate EDAM transmission service providers for any historic, reduced transmission service revenues under EDAM compared with the revenues they earned prior to participation in EDAM in case the EDAM transmission service providers sell fewer short-term firm and non-firm transmission services because such services will be displaced by EDAM efficient energy transfers. In effect, the three components serve as a proxy to determine the benefits the broader market will receive from new entrants.

40. Q. HOW ARE THESE COSTS TO BE DETERMINED?

A. To determine the costs eligible for recovery through the EDAM access charge, EDAM transmission service providers will first calculate their recoverable revenue based on their average rate approved by FERC for the three years prior to joining EDAM. The costs recoverable through the EDAM access charge consist of the difference between the EDAM recoverable revenue and actual transmission recovered revenue eligible for recovery. The rate is static until changed by the transmission service provider , thereby incentivizing it to keep costs at or below the rate to avoid losses.

To ensure full transparency in the application of the EDAM access charges, CAISO proposes to require EDAM entities, on behalf of their EDAM transmission service providers, to provide CAISO with all documentation necessary to determine each component of the EDAM access charge by July 1 of the calendar year preceding each year the EDAM access charge will apply. CAISO will then publish on its website all documentation provided, allowing market participants to review the documentation for sufficiency and accuracy. At a minimum, EDAM entities' documentation will include: (1) the final order from the Commission or the local regulatory authority effecting the approved transmission rates, including any informational filings or postings under formula rates; (2) the sums for each recoverable revenue component and true-up; and (3) an authorized affidavit from each EDAM transmission owner attesting to the accuracy of the data provided, and that the EDAM transmission service provider will make reasonable efforts to ensure any recovery through the EDAM access charge will not result in any double recovery of costs. All data must be sufficiently granular to enable verification of the EDAM access charge rates by CAISO and market participants.

For each EDAM transmission service provider, CAISO will maintain on its website the current sum of each recoverable revenue component, the total true-up amount, and the total eligible recovery amount. CAISO also will maintain on its website each EDAM access charge, including the rate, the gross load, and the total eligible recovery amount in that balancing authority area, similar to how CAISO maintains data for its participating transmission service providers' transmission access charges. Further, CAISO will: (1) engage with prospective EDAM transmission service providers prior to implementation,

(2) facilitate annual reviews after submission of the required information and prior to the upcoming year, and (3) develop a comprehensive report on performance of the EDAM access charge based on the first three years of operation. CAISO also included a requirement in its tariff that it will conduct a holistic review of the EDAM access charge after three years of use.

CAISO will engage with EDAM transmission service providers/owners, CAISO transmission owners, and stakeholders to review the effectiveness of the EDAM access charge. CAISO will publish on its website a performance report on the EDAM access charge. The performance report will include without limitation: (1) an explanation of the impacts of the EDAM access charge on EDAM transmission service providers' revenue recovery and rates; (2) the performance of the EDAM access charge in managing cost shifts among customers; and (3) an analysis by CAISO of any other impacts or externalities.

41. Q. HOW ARE THE COSTS ASSOCIATED WITH THE EDAM ACCESS CHARGE ALLOCATED?

A. CAISO will allocate these costs to gross load across the EDAM area, a $/MWh rate. CAISO allocates the costs to gross load because load across the EDAM area ultimately and primarily benefits from the optimized transfers that will occur with EDAM participation across the market footprint.

Once collected through the EDAM access charge, CAISO will allocate revenues collected to EDAM entities on behalf of each EDAM transmission service provider located in its balancing area, in proportion to each EDAM transmission service provider's share of EDAM projected recoverable revenue shortfalls. For example, if EDAM transmission service provider A expected to recover $6 million from the EDAM access charge, and EDAM transmission service provider B expected to recover $4 million, and CAISO collected $12 million through the access charge, transmission service provider A would receive $7.2 million and transmission service provider B would receive $4.8 million. The same calculation would apply if CAISO recovered less than expected through the access charge. In either situation, the CAISO Tariff requires that any under-or-over-recovery be rolled into the next year's forecasted recoverable revenue from the access charge, thus keeping all transmission owners whole. CAISO has managed its own transmission access charge in the same way for years without issue.

This true-up will help right-size the EDAM access charge year-to-year based on expected collections and actual collections. Critically, the annual true-up corrects any inaccurate projections based on actual collections each year. The true-up thus protects ratepayers throughout the EDAM area from over- or under-collection, ensuring just and reasonable rates year-to-year. The true-up also mitigates any incentive for an EDAM transmission service provider to over-project its potential shortfalls because it will know that eventually it will be able to collect the correct amount, and therefore does not need to add any cushion for an inaccurate projection. Likewise, if an EDAM transmission service provider does over-project its necessary recovery based on historical data, the true-up provision will correct the projection in the next year.

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<u>EDAM and Greenhouse Gas (GHG)</u>

42. Q. PLEASE DESCRIBE HOW EDAM WILL ACCOUNT FOR GHG EMISSIONS.

A. EDAM's GHG accounting design reflects the WEIM resource-specific design to identify resources serving demand in GHG pricing areas. EDAM extends the existing WEIM framework where resources can voluntarily elect whether to submit a bid adder to signal a willingness to serve load in a GHG pricing area (*i.e.* California or Washington GHG pricing areas). This approach allows resource scheduling coordinators to recover their cost of compliance with a state's carbon pricing policy if they voluntary elect to serve load in a specific GHG pricing area. Resources located within GHG pricing areas do not submit bid adders but instead include the cost of compliance with any GHG program within their energy bids. Importantly, dispatch and pricing for resources located in non-GHG pricing areas (*e.g.*, Nevada), to serve load in non-GJHG pricing areas do not reflect GHG compliance costs.

EDAM will have an optimized GHG counterfactual. This will enable CAISO to identify reference schedules to reflect what dispatch would have occurred without GHG transfers. These reference schedules allow the market to identify an eligible MW value for EDAM resources located outside of a GHG regulation area to receive an attribution in the integrated forward market to serve demand in a GHG regulation area. This feature will help mitigate the potential for secondary dispatch (*i.e.*, backfill of other resources, which when it comes from a higher emitting resource, could result what some states refer to as "emissions leakage") and ensure low-cost energy is available to serve load in the EDAM balancing authority areas outside of GHG pricing areas.

EDAM will also include a GHG net export constraint to reduce the potential for secondary dispatch. This constraint prevents the attribution of transfers to a GHG pricing area to resources located in balancing authority areas outside of that GHG pricing area in intervals when those balancing authority areas are net importers or in excess of a balancing authority areas net transfers. The market will relax this constraint when any balancing authority area that overlaps with a GHG pricing area does not pass the RSE to avoid unnecessarily impacting grid reliability.

43. Q. HOW, IF AT ALL, CAN EDAM PROVIDE TRANPARENCY INTO GHG EMISSIONS IN STATES THAT HAVE NOT PRICED CARBON?

A. EDAM will also support utilities and states' evaluation of compliance with emission reduction programs in areas that have not priced GHG emissions. Currently, GHG accounting design has reflected price-based emissions policies, like those adopted by California and Washington. However, some climate policies seek to reduce emissions attributed to electric load without pricing carbon. In the context of EDAM and WEIM, CAISO has an ongoing stakeholder initiative focused on how CAISO may provide a means for reporting entities, including utilities, to assess which resources operated to support load in regions that do not price GHG as well as insight into the hourly residual emissions intensity when that utility is a net importer.

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<u>Other EDAM Design Elements</u>

44. Q. DOES EDAM SUPPORT PARTICIPATION FROM DISTRIBUTED ENERGY RESOURCES AND DEMAND RESPONSE AGGREGATORS?

A. Yes. EDAM supports participation from distributed energy resources and demand response aggregators through two models: non-participating demand response (load forecast adjustment) and supply-side participation of load curtailment & customer resources.

The load forecast adjustment model allows balancing authority areas to reduce or increase their forecasted load submitted to CAISO to represent their demand response event. This demand response is not market-dispatched or price-responsive; instead, the balancing authority area retains full control over how and when demand response is called upon. These adjustments are factored in the market's scheduling forecast. If actual load reductions exceed expectations, the resource may receive a positive settlement; underperformance may result in a charge. This model is appropriate for utilities that deploy demand response as a reliability or operational tool outside the market.

The second approach, via supply-side models, allows demand response aggregators and distributed energy resource providers to offer resources directly in the market. These resources are price-responsive and scheduled in day-ahead or dispatched in real-time based on the clearing of those economic bids in the market. Participation is more structured and includes two resource models:

- Proxy Demand Resources (PDR) is a market participation model that enables aggregation of customer load curtailment capabilities and bidding of that load reduction into the wholesale energy and ancillary services markets.
- Distributed Energy Resource Providers (DERPs) is a market participation model that allows for an aggregation of Distributed Energy Resources (DERs), inclusive of demand curtailment resources, to act as one "virtual" resource. This is CAISO's FERC Order 2222-compliant model.

These supply-side models may require telemetry and metering but allow full market participation and compensation based on performance.

45. Q. PLEASE EXPLAIN THE EDAM'S APPROACH TO VIRTUAL BIDDING.

A. Based on stakeholder input, the current EDAM design as approved by FERC will allow EDAM transmission service providers to enable virtual bidding in their balancing areas at the onset of their participation in EDAM, but will not mandate it. CAISO already allows virtual bidding within its balancing area and will continue to do so. No other incoming EDAM Entity has signaled the need for virtual bidding within its area. Once EDAM participation begins, stakeholders and CAISO will evaluate the need for a stakeholder process to determine a permanent virtual bidding design for the EDAM. The optional transition period will give EDAM transmission service providers, their customers, market participants, and regulators experience and comfort with day-ahead markets before enabling virtual bidding.

46. Q. PLEASE EXPLAIN THE EDAM'S APPROACH TO EXTERNAL RESOURCE PARTICIPATION.

A. The determination as to whether or not to enable external participation in the market is given to the EDAM participating balancing areas who maintain their NERC reliability obligations. FERC approved this approach, disagreeing with comments that CAISO should have a mechanism to enable economic bidding at external interties within the CAISO Tariff, rather than allowing economic bidding at interties to be enabled by the EDAM Entity under section 29.34(*i*)(2).

<u>EDAM Data Availability</u>

47. Q. PLEASE DISCUSS THE AVAILABILITY OF EDAM DATA.

A. CAISO produces and makes publicly available a significant amount of market information on its Website (<u>https://www.caiso.com</u>) and its Open Access Same-Time Information System ("OASIS") webpage (<u>https://oasis.caiso.com/mrioasis/logon.do</u>). CAISO's OASIS page contains a wide breadth of granular market data which market participants download on a daily basis. This includes outage information, demand forecasts, market prices, market results data, and transmission availability. With the implementation of EDAM, the OASIS page will scale that data to include EDAM-wide market information including after-the-fact RSE data.

Once the EDAM launches in May 2026, CAISO will produce monthly public reports on EDAM performance developed by the CAISO market analysis team. These reports will contain data on market trends, how the market is performing, and market congestion among others. Separately, CAISO will publish quarterly EDAM benefits reports as it does today with the WEIM which will include estimated economic benefits to participating entities.

CAISO also hosts a series of stakeholder forums to share market information, which will in the future include EDAM related information. For example, CAISO hosts a bi-weekly market update stakeholder call to discuss market results data and market trends. On a quarterly cadence, CAISO hosts a market planning and performance forum where CAISO staff discuss more broadly market trends and performance, and market activities, which will also include EDAM related trends and information.

Additionally, CAISO engages regionally in a variety of forums to disseminate the information included in its reports. The Regional Issues Forum discusses WEIM and EDAM issues and any other relevant stakeholder initiative;[8] ongoing policy initiatives are discussed in open stakeholder meetings;[9] the Release User Group discussions consider issues related to the software changes;[10] and the Technical User Group discussions evaluate solutions for technology- and process-based problems.[11]

The Department of Market Monitoring ("DMM") will also monitor EDAM related data. The DMM issues very informative annual and quarterly reports on market trends and market operations and provides updates to the WEM Governing Body and the CAISO Board of Governors, and reports on specific issues.[12]

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8 https://www.westerneim.com/Pages/Governance/RegionalIssuesForum.aspx.
9 https://stakeholdercenter.caiso.com/.
10 http://www.caiso.com/informed/Pages/MeetingsEvents/UserGroupsRecurringMeetings/Default.aspx.
11 https://www.caiso.com/meetings-events/topics/technical-user-group-tug.
12 https://www.caiso.com/market-operations/market-monitoring.

Settlements and Dispute Resolution

48. Q. WILL CAISO USE ITS EXISTING DAY-AHEAD MARKET PROCESSES TO SETTLE EDAM?

A. The EDAM will settle in accordance with the CAISO Tariff-based timelines and procedures associated with settlement of all market participant transactions. CAISO will assess and settle all day-ahead market charges in EDAM in the same manner as it does in the CAISO balancing area today; however, there are some unique dimensions to EDAM that necessitate additional EDAM-specific settlement provisions. These arise in the context of the RSE surcharge, the greenhouse gas accounting rules, and in the context of transfer and congestion revenues allocated between balancing areas.

EDAM will introduce approximately 53 new settlement charge codes versus the WEIM; such as illustrated in Figure 7.

Figure 7

Settlement Charge Codes

EDAM Entity	Merchant SC	Chg Code #	Chg Code Name
	X	491	Greenhouse Gas Emission Cost Revenue
	X	4515	GMC Bid Transaction Fee
X	X	4560	GMC Market Services Charge
X	X	4561	GMC System Operations Charge
	X	4563	GMC Transmission Ownership Rights Charge
X	X	6011	Day Ahead Energy, Congestion, Loss Settlement
?		6476	Real Time Assistance Energy Transfer Surcharge
X		6478	Real Time Imbalance Energy Offset - System
X		6479	Real Time Assistance Energy Transfer Allocation
X	X	6483	Hour-Ahead Scheduling Process Uplift Settlement
	X	6630	IFM Bid Cost Recovery Settlement
X	X	6636	IFM Bid Cost Recovery Tier 1 Allocation
X	X	6637	IFM Bid Cost Recovery Tier 2 Allocation
	?	6788	Real Time Market Congestion Credit Settlement
X	X	6806	Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation
X	X	6807	Day Ahead Residual Unit Commitment (RUC) Tier 2 Allocation
X		6947	IFM Marginal Losses Surplus Credit Allocation
	X	6984	RTM Net Marginal Loss Assessment per CAISO Agreement
X	X	7070	Flexible Ramp Forecast Movement Settlement
X	X	7071	Daily Flexible Ramp Up Uncertainty Capacity Settlement
X		7076	Flexible Ramp Forecast Movement Allocation
X	X	7077	Daily Flexible Ramp Up Uncertainty Award Allocation
X	X	7078	Monthly Flexible Ramp Up Uncertainty Award Allocation
X	X	7081	Daily Flexible Ramp Down Uncertainty Capacity Settlement
X	X	7087	Daily Flexible Ramp Down Uncertainty Award Allocation
X	X	7088	Monthly Flexible Ramp Down Uncertainty Award Allocation
	X	8071	Day Ahead Imbalance Reserve Up Settlement
X		8076	Day Ahead Imbalance Reserve Up Tier 1 Allocation
X		8077	Day Ahead Imbalance Reserve Up Tier 2 Allocation
X		8080	Resource Sufficiency Surcharge
	X	8081	Day Ahead Imbalance Reserve Down Settlement
X		8086	Day Ahead Imbalance Reserve Down Tier 1 Allocation
X		8087	Day Ahead Imbalance Reserve Down Tier 2 Allocation
X		8088	Resource Sufficiency Surcharge Revenue Allocation
	X	8310	Day Ahead GHG Settlement
X		8315	Day Ahead GHG Offset
X		8404	Day Ahead Energy Offset - System
X		8704	Day Ahead Congestion Offset
X		8800	Day Ahead RUC Reliability Capacity Up Settlement
X	?	8806	Day Ahead Reliability Capacity Up Tier 1 Allocation
X	?	8807	Day Ahead Reliability Capacity Up Tier 2 Allocation
X		8810	Day Ahead RUC Reliability Capacity Down Settlement
X	?	8816	Day Ahead Reliability Capacity Down Tier 1 Allocation
X	?	8817	Day Ahead Reliability Capacity Down Tier 2 Allocation
X	X	64600	FMM Instructed Imbalance Energy EIM Settlement
X	X	64700	Real Time Instructed Imbalance Energy EIM Settlement
X		64770	Real Time Imbalance Energy Offset EIM
	X	66200	Bid Cost Recovery EIM Settlement
X		#NEW#	Real Time Market GHG Offset
?		#NEW#	TRR Recovery Payment
?		#NEW#	TRR Recovery Charge
X		#NEW#	Day Ahead Transfer Revenue Settlement
X		#NEW#	RTM Transfer Revnue settlement
43	*31*	*53*	*Count of Charges*

49. Q. PLEASE DESCRIBE CAISO'S SETTLEMENT DISPUTE RESOLUTION PROCESS.

A. CAISO Tariff and processes establish opportunities and procedures for managing settlement disputes. Similar to the process employed for the WEIM today, the intake of settlement disputes initiated by EDAM participants in the day-ahead market will be subject to existing tariff section 11.29.8 and managed through the CAISO's customer inquiry, dispute, and information

("CIDI") system. EDAM participants follow these same settlement dispute resolution procedures, whereby most settlement disputes are resolved. Unresolved settlement issues and other disputes must also follow the dispute resolution procedures described in existing tariff section 13, which requires parties to engage in informal good-faith negotiations and mediation before resorting to arbitration. In addition, EDAM participants benefit from several transitional protective measures to mitigate market risks for a period up to six months after implementation which should reduce the potential for disputes.

<u>The CAISO Market Monitoring Process</u>

50. Q. PLEASE DESCRIBE THE CAISO'S MARKET MONITORING PROCESS.

A. The mission of CAISO's Department of Market Monitoring ("DMM") is to provide independent oversight and analysis of the CAISO's markets for the protection of consumers and market participants by the identification and reporting of market design flaws, potential market rule violations, and market power abuses. In accordance with FERC's requirements, the DMM reports to the CAISO Board of Governors. The DMM is managed through the DMM Oversight Committee, which consists of two CAISO Board of Governors members and a Western Energy Market Governing Body member as an observer.

DMM's core functions as defined in FERC regulations and the CAISO Tariff are to: (1) review and report on the performance of wholesale markets, including quarterly and annual reports; (2) evaluate existing and proposed market rules, and provide recommendations; and (3) notify FERC Office of

Enforcement when a market participant or CAISO has engaged in conduct that may require investigation. In addition, DMM performs functions related to inputs for market power mitigation.

DMM operates as an internal business unit of CAISO, with a staff of approximately 18 employees who have expertise in economics, data analysis, and engineering. DMM has access to all market and operational data.

Under Attachment P of the CAISO Tariff, DMM shall consider requests from a State Commission for specifically identified information or data concerning general market trends and the performance of the wholesale markets. DMM may deny a request when it determines, in its sole discretion, that complying with a request would be unreasonably burdensome or if it would interfere with the core market monitoring functions of DMM, although these restrictions do not apply to otherwise enforceable subpoenas, court orders, or any other form of compulsory process issued by, or on behalf of, a state Commission.

51. Q. PLEASE DESCRIBE HOW CAISO MITIGATES MARKET POWER.

A. CAISO allows market-based energy offers limited by an offer cap and subject to a local market power mitigation test that identifies potential for uncompetitive conditions. If uncompetitive conditions are identified, CAISO replaces market-based energy offers with the administratively calculated default energy bid which can be established through different processes.

The purpose of local market power mitigation is to mitigate the market effects of energy bids above marginal costs when a transmission constrained areas are structurally uncompetitive. An area is structurally uncompetitive when market participants can exert market power by submitting bids above marginal costs that set the market clearing price. The local market power mitigation market software includes a dynamic competitive path assessment that tests whether energy to relieve binding transmission constraints is competitive or non-competitive in the day-ahead and real-time markets.

When a resource's bid is mitigated, the CAISO market systems substitute the default energy bid (i.e., the cost-based marginal bid) for the resource's bid in the market clearing process, which may set the market clearing price, and uses the default energy bid to determine the resource's bid cost recovery compensation. Each scheduling coordinator can choose one of three options for calculating default energy bids for a resource: (1) the variable cost option; (2) the negotiated rate option; or (3) the LMP option. For a natural gas-fired resource subject to the variable cost option, the default energy bid is based on incremental fuel costs, which is determined by using gas prices published in natural gas price indices. All default energy bids under the variable cost option include an adder of 10 percent to the CAISO's calculation of costs based on the gas price indices. CAISO calculates default energy bids for the day-ahead and real-time markets, respectively, using the gas commodity price formulas.

Commitment cost offers (start-up bids, minimum load bids and transition bids) are not subject to dynamic mitigation but are limited to a cost cap and validation of commitment costs. The validation determines if the cost offers are within a reasonable range of CAISO's expectations of unit's costs (i.e., 125 percent of proxy costs. If suppliers submit cost-based commitment cost offers in excess of this range set by the cost cap, the commitment cost offers are adjusted down to the maximum allowable level.

52. Q. WHAT IS THE MARKET SURVEILLANCE COMMITTEE?

A. As defined in Appendix O of the CAISO Tariff, the Market Surveillance Committee ("MSC") is an independent advisory group of at least three industry experts experienced in economics with emphasis on antitrust, competition and market power. They are familiar with generation and transmission operations, legal issues in regulated operations, and gaming behavior in energy and other commodity markets. Unless a discussion involves confidential information, MSC meetings are open to the public. The MSC periodically produces written reports containing their recommendations. Importantly, the MSC provides review of developing policy proposals through public meetings to share their independent market expert perspectives and may also provide written opinions on proposals for consideration as these are presented to the governing entity for decision.

Currently, the membership of the MSC consists of: James Bushnell from the Department of Economics, at University of California, Davis; Scott Harvey of FTI Consulting; and Benjamin Hobbs of Hobbs Energy & Environment Decisions Research Group at the Johns Hopkins University.

Conclusion

53. Q. DO YOU HAVE ANY FINAL COMMENTS ON THE EDAM DESIGN?

A. CAISO fully expects that EDAM will represent an area of ongoing attention, particularly in the earlier years of operation, and remains committed to ensuring both a successful launch and ongoing improvement and design evolution. Further evolution of the market design will be informed by operational experience and input from the diverse stakeholder perspectives representative of the West, similar to how experience has driven the evolution of the WEIM. CAISO and its independent market monitor and experts will also monitor market operations and offer perspectives from its market experts when engaging participants, regulators, and other stakeholders in these efforts.

54. Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ANNA McKENNA, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: October 21, 2025

Anna McKenna

STACEY CROWLEY

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy

Extended Day-Ahead Market Energy Supply Plan Amendment
Docket No. 25-10___

Prepared Direct Testimony of

Stacey Crowley

Introduction

1. Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Stacey Crowley. I am the Vice President of External Affairs for the California Independent System Operator ("CAISO"). My business address is 250 Outcropping Way, Folsom, California 95630. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra") (together, "NV Energy").

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF EXTERNAL AFFAIRS.

A. As Vice President of External Affairs, my responsibilities include managing CAISO's engagement with external stakeholders across the Western Interconnection. This includes state, regional, and federal affairs, regional coordination and communications. In California, my responsibilities focus on legislative and executive branch affairs, while regulatory matters are managed separately. Additionally, I am responsible for supporting the governance processes for the Western Energy Markets (Western Energy Imbalance Market ("WEIM") and the Extended Day-Ahead Market ("EDAM") and facilitating engagement with stakeholder committees and current and prospective market participants. My responsibilities also include overseeing CAISO's overall digital presence, media relations and communications.

3. Q. WOULD YOU PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE?

A. In addition to my current responsibilities, during the 12 years that I have been at CAISO I have contributed to initiatives to evolve market governance, informing stakeholders and enhancing regional energy collaboration. These include development of the Western Energy Markets ("WEM") Governing Body and associated committees (the Body of State Regulators, the WEM Nominating Committee, and the Regional Issues Forum), and the growth of WEIM to include over 80 percent of the West. Prior to joining CAISO, I served as Director of the Nevada Governor's Office of Energy and as an energy policy advisor to Nevada Governor Brian Sandoval. Earlier in my career I practiced architecture for 15 years, focusing on environmentally responsible design and development. I hold a Bachelor of Science in Architecture from the University of Michigan and a Master of Architecture from the University of New Mexico.

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony, I provide an overview of governance, the state and stakeholder committees, relevant work of the West-wide Governance Pathways Initiative, the public tariff amendment process, opportunities for the

Commission to participate in the amendment process prior to a filing at the Federal Energy Regulatory Commission ("FERC"), status of the EDAM and applicable timeline for new entrants to join (implementation process), the EDAM Implementation Agreement, and the EDAM exit process.

<u>The CAISO Governance and Stakeholder Processes</u>

5. Q. PROVIDE AN OVERVIEW OF MARKET GOVERNANCE.

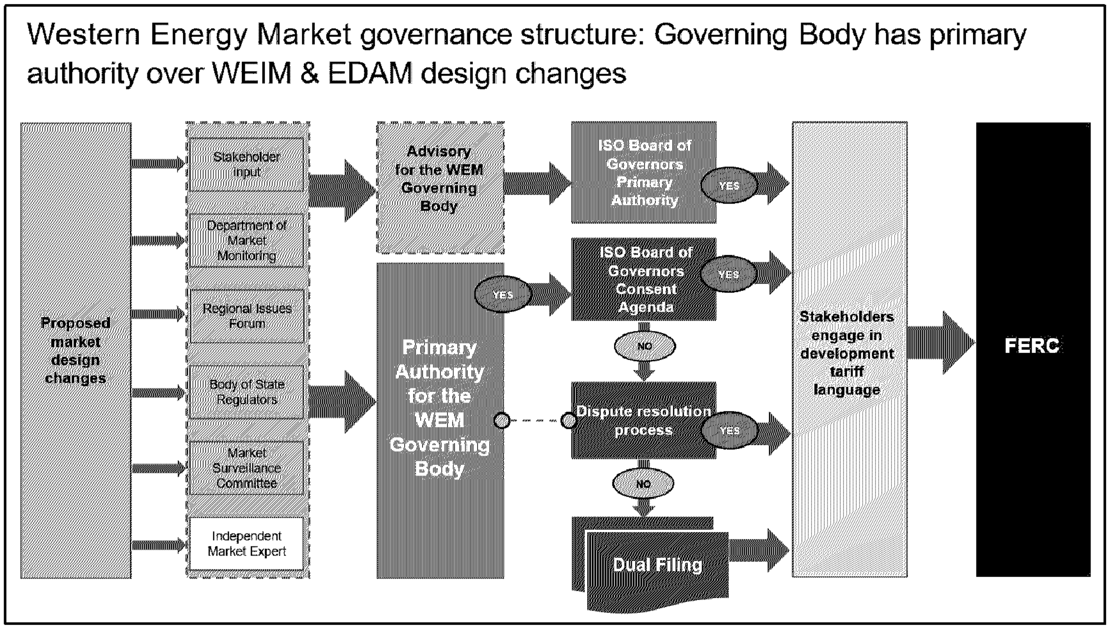
A. As of July 1, governance of the Western Energy Markets (including the WEIM and the EDAM) is under the primary authority of the WEM Governing Body. Through CAISO bylaws, the CAISO Board of Governors has delegated certain authority to the WEM Governing Body to approve or reject amendments to the tariff that apply to WEIM/EDAM, including those applicable to the WEIM/EDAM entity, balancing authority areas, or market participants within their balancing authority areas. The Charter for WEIM and EDAM Governance establishes the scope of the WEM Governing Body's authority over market rule changes and details the WEM Governing Body's responsibilities, and the administration of meetings and support from CAISO staff. As defined in the Charter, the mission of the WEM Governing Body is to "promote, protect and expand the success of the Western Energy Markets, meaning both the Western Energy Imbalance Market ("WEIM") and the Extended Day Ahead Market ("EDAM"), for the benefit of their participants as a whole and the consumers they serve, with due consideration of the interests of all participants in CAISO's real-time and day-ahead markets, including both participants transacting in CAISO's balancing authority area and participants transacting in WEIM/EDAM balancing authority areas (meaning the balancing authority areas of the WEIM/EDAM entities, collectively)."

Before consideration by the CAISO Board of Governors and the WEM Governing Body, CAISO staff uses a decisional classification framework to identify whether a particular initiative is subject to the primary authority of the WEM Governing Body or to the CAISO Board of Governors.[1] Issues that apply to WEIM or EDAM will be subject to the primary authority of the WEM Governing Body. The WEM Governing Body may provide advisory input over proposals that would apply to the real-time and/or day-ahead market but are not within the scope of its primary authority. And, as noted in Question 20, all market initiatives needing tariff changes are subject to a rigorous and public stakeholder process. Following approval, there is an additional stakeholder review of the tariff modifications before filing for FERC approval. See Figure 1 below for a graphical representation of the public stakeholder and decision-making process.

[1] https://www.westerneim.com/Documents/Decisional-Classification-Guidance-for-Handling-Policy-Initiatives-WEM-Governing-Body.pdf.

Figure 1

WEM Governance Structure



6. Q. **HOW IS THE CAISO BOARD OF GOVERNORS SELECTED?**

A. California State Law established CAISO as a non-profit, public benefit corporation to ensure reliability of electric service and the health and safety of the public.[2] A five-member independent Board is appointed by the Governor of California and confirmed by the state senate.[3] The CAISO Board of Governors reaches decisions based on a majority vote of its five members.

[2] *See* CAL. PUB. UTIL. CODE Article 3, §§ 345-352.7, available at: https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=2.3.&article=3.

[3] *See* CAL. PUB. UTIL. CODE § 337(a) ("The Independent System Operator governing board shall be composed of a five-member independent governing board of directors appointed by the Governor and subject to confirmation by the Senate.")

7. Q. **HOW IS THE WEM GOVERNING BODY SELECTED?**

A. The Selection Policy for the WEM Governing Body establishes the process for identifying and selecting members, subject to confirmation by the Governing Body itself.[4] It provides selection criteria, creates a stakeholder nominating committee, and includes timelines and other process steps, with the goal of concluding the selection process before the terms of the sitting members expire. The nominating committee has eight members, consisting of one representative each from the following sectors or groups: (1) WEIM and EDAM Entities, (2) participating transmission owners, (3) publicly-owned utilities, (4) suppliers and marketers of generation and energy service providers, (5) the Body of State Regulators, (6) the WEM Governing Body, (7) the CAISO Board of Governors, and (8) public interest or consumer advocate groups.

Each sector determines its own method of selecting a representative to serve on the nominating committee, and the term of service. The minimum term of service is one year. The nominating committee shall act on the consensus of its voting members. The representatives from the WEM Governing Body and CAISO Board of Governors are non-voting members.

If a Governing Body Member whose term is scheduled to expire has expressed a desire to be nominated for a new term, the nominating committee determines whether it wants to re-nominate the sitting Member without interviewing other candidates. If the nominating committee does not decide to proceed in this manner, then it determines which set of diverse qualities would best complement the remaining Members and asks an executive search firm to

[4] https://www.westerneim.com/Documents/Selection-Policy-WEM-GoverningBody.pdf.

identify at least two qualified candidates to interview, in addition to the sitting Member.

Optimally, the nominating committee's selections should ensure that the overall composition of the WEM Governing Body reflects a diversity of perspectives that may result from different areas of expertise, geographic background, ethnicity, gender and professional backgrounds, and life experience. Similarly, no one state or sub-region in the West should have excessive representation—meaning Members whose place of residence or work history tends to associate them with a particular Western state. The nominating committee strives to ensure that the Governing Body includes at least one Member with expertise in Western electric systems and markets. If the nominating committee can identify a qualified candidate with a Western background who has as strong overall experience and knowledge as the other candidates, and all other factors being equal, the nominating committee should prefer the candidate with a Western background.

The slate submitted by the nominating committee is subject to approval by the WEM Governing Body in a noticed public session. If the decision occurs before the end of the expiring terms, the WEM Governing Body member whose term is expiring will be recused from the approval decision. The WEM Governing Body must accept or reject the slate as a whole. If the slate is accepted, the nominees will become Members of the WEM Governing Body upon execution of a services agreement with CAISO.

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d/b/a NV Energy

8. Q. HOW IS DECISIONAL AUTHORITY SHARED BETWEEN CAISO'S BOARD OF GOVERNORS AND THE WEM GOVERNING BODY?

A. As noted in Question 5, the WEM Governing Body has "primary authority" to approve or reject a proposal:

> [T]o approve or reject a proposal to change or establish a tariff rule applicable to the WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within the WEIM/EDAM Entity balancing authority areas, in their capacity as participants in the WEIM/EDAM. The WEM Governing Body will also have primary authority to approve or reject a proposal to change or establish any tariff rule for the day-ahead or real-time markets that directly establishes or changes the formation of any locational marginal price(s) for a product that is common to the overall WEIM or EDAM markets. The scope of this primary authority excludes, without limitation, any other proposals to change or establish tariff rule(s) applicable only to CAISO's balancing authority area or to the CAISO-controlled grid.

The WEM Governing Body may provide advisory input over any proposals to change or establish tariff rules that would apply to the real-time and/or day-ahead market but are not within the scope of primary authority.

Under the primary authority construct, the WEM Governing Body must approve an initiative that will then be placed on the consent agenda for the CAISO Board of Governors. A dispute resolution process, as outlined in the

Charter for WEIM and EDAM Governance and shown in Figure 1 above, will be triggered in the event an item on the consent agenda is not approved by the CAISO Board of Governors that has been approved by the WEM Governing Body. The process includes holding a joint meeting where members that disagree with the proposal can articulate their concerns to help CAISO staff in identifying changes that could make it acceptable. After additional stakeholder proceedings, and if the dispute resolution process fails to result in a consensus proposal, then the tariff allows for the submission of two filings to FERC, under Section 205 of the Federal Power Act, presented in a single document, with one proposal representing the initiative as approved by the WEM Governing Body and the other representing the initiative as approved by the CAISO Board of Governors.[5] Alternatively, the CAISO Board of Governors alone may authorize a FERC filing if, and only if, the Board, by unanimous vote, makes a finding that the two bodies have reached an impasse and exigent circumstances exist such that a tariff amendment is critical to preserve reliability or to protect market integrity. There has never been an occasion to date under which either the dispute resolution process or the exigent circumstance process has been triggered.

9. Q. DOES THE WEM GOVERNING BODY HAVE ADDITIONAL INDEPENDENT SOURCES OF EXPERTISE?

A. Yes. The WEM Governing Body has authorization to retain the Western Energy Markets Governing Body Market Expert ("Market Expert") to provide explanations and technical opinions, as requested by the WEM Governing Body, to aid it in making well-informed decisions. As requested by the WEM Governing Body, the Market Expert produces reports and opinions and

[5] https://www.westerneim.com/Documents/Charter-for-WEIM-and-EDAM-Governance.pdf.

evaluates the fairness and efficacy of proposed market rule changes, business practices, market operations and price formation. The Market Expert helps the WEM Governing Body understand complex market topics and provides information on best practices from other markets. Dr. Susan Pope currently serves as this independent expert in support of the WEM Governing Body.[6]

10. Q. PLEASE DESCRIBE THE BODY OF STATE REGULATORS.

A. The Charter for WEIM and EDAM Governance also establishes the Body of Regulators ("BOSR") consisting of one commissioner from each of the state public utilities commissions in which a load-serving utility participates in the WEIM or EDAM, including both the CAISO Balancing Authority Area and any other Balancing Authority Area participating in either WEIM or EDAM. Each state public utilities commission selects its own representative to the body. When necessary, a state public utilities commission may select a representative who is not a commissioner. Currently, PUCN Chair Hayley Williamson serves as Nevada's representative to the BOSR.[7] Additionally, liaisons who represent three other sectors—consumer-owned utilities, public-owned utilities, and federal power marketing administrations—also participate in BOSR discussions. The BOSR is self-governing and membership in the BOSR does not restrict members from taking any position before FERC, CAISO or any other forum concerning matters related to CAISO or its markets.

[6] https://www.westerneim.com/Documents/SusanPope.pdf.
[7] https://www.westernenergyboard.org/western-energy-imbalance-market-body-of-state-regulators/eim-bosr-members/.

The BOSR provides a forum for state regulators to learn about the WEIM and EDAM, or other CAISO matters related to their jurisdictional responsibilities. The BOSR may express a common position in the stakeholder process or to the WEM Governing Body, stakeholders, or FERC.

11. Q. HOW IS BOSR FUNDED?

A. CAISO provides staff support to the BOSR. This includes facilitation of meetings, if requested by the BOSR, education and information about WEIM or EDAM and the activities of the WEM Governing Body, and reimbursement for travel expenses incurred by one representative from each state commission to attend meetings, to the extent reimbursement is requested and permitted under applicable state ethics rules.

In 2021, the BOSR entered into a Memorandum of Understanding[8] with the Western Interstate Energy Board ("WIEB"), an organization of 11 Western States and two Canadian Provinces, to provide additional expertise to assist in evaluation of stakeholder initiatives and market activities. Costs for the WIEB support are allocated to the state regulated market participants through individual funding agreements directly to WIEB, and the budget is reviewed annually.[9]

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[8] https://www.westernenergyboard.org/wp-content/uploads/2019/11/08-12-19-wieb-eim-bosr-mou-1.pdf.
[9] https://www.westernenergyboard.org/western-energy-imbalance-market-body-of-state-regulators/state-regulated-market-participant-funding-agreement/.

12. Q. ARE THERE OTHER AVENUES FOR STAKEHOLDER INPUT?

A. Yes. The Regional Issues Forum ("RIF")[10] is an additional avenue for providing information and opinions on different aspects of the market and soliciting stakeholder feedback and perspectives. The RIF is an independent, self-governing body that includes stakeholder representatives from the following sectors: EDAM Entities, WEIM Entities, CAISO participating transmission owners, public and consumer interest advocates, consumer-owned utilities, independent power producers and marketers, and federal power marketing administrations.

The role of the RIF has evolved since its creation in December 2015. In the spring of 2021, a revision to the Charter expanded the scope of RIF's purview to include ongoing CAISO stakeholder processes. The RIF is responsible for holding at least three public meetings annually and for reporting to the WEM Governing Body on the forum's activities. The RIF hosts a roundtable discussion at the beginning of CAISO's annual policy roadmap process, to discuss and develop their preferred priorities within the set of possible discretionary initiatives. Actions taken by the RIF are done by consensus, but where there are differing views, minority and majority positions may be documented and offered to the WEM Governing Body.

13. Q. WHAT IS THE WEST-WIDE GOVERNANCE PATHWAYS INITIATIVE?

A. The West-Wide Governance Pathways Initiative ("Pathways Initiative") was established in 2023 in response to a letter from regulators in five Western states on July 14, 2023. Their letter set forth a vision for "ensuring that the

[10] https://www.westerneim.com/Pages/Governance/RegionalIssuesForum.aspx.

benefits of wholesale electricity markets are maximized for customers across the entire Western U.S." and proposed the creation of a new entity "that could serve as a means for delivering a market that includes all states in the Western interconnection." The 2023 letter invited stakeholders and state regulators to collaborate in developing this concept, with the goal of maintaining and expanding upon "the benefits of WEIM and EDAM" while "avoiding a duplication of the investments and expenses of the market infrastructure that has already been created." In response, stakeholders representing a diverse set of utilities, consumer advocates, public power, labor, generators and power marketers, public interest organizations, and others have formed the Pathways Initiative Launch Committee ("Launch Committee"), which focused on developing potential options consistent with the state regulators' vision. The Launch Committee follows an iterative stakeholder process, whereby it uses working groups to develop and present written proposals for public stakeholder comment and then refines the proposals based on stakeholder input. In 2024, the Launch Committee set forth what it described as a stepwise approach to continued evolution of the governance over WEIM and EDAM. It adopted both a Step 1[11] and a Step 2[12] recommendation, intended to evolve the governance in sequence toward greater independence.

14. Q. HOW DOES CAISO INTERACT WITH THE PATHWAYS INITIATIVE LAUNCH COMMITTEE?

A. CAISO is not a member of the Launch Committee. Instead, CAISO staff serve as a technical resource for the Launch Committee and its working groups,

[11] https://www.westernenergyboard.org/wp-content/uploads/Step-1-Recommendation_Final-Draft-Update-5.28.24-1.pdf.
[12] https://www.westernenergyboard.org/wp-content/uploads/Pathways-Initiative-Step-2-Final-Proposal.pdf.

when requested, on topics where CAISO staff have relevant information or expertise.

15. Q. WHAT CHANGES DID PATHWAYS RECOMMEND AS STEP 1?

A. As of July 1, 2025, the governance changes proposed by the Pathways Initiative in its Step 1 proposal are now effective. They were transmitted to and jointly approved through a public process by the WEM Governing Body and the CAISO Board of Governors in October 2024, and necessary changes to the tariff were approved by FERC in April 2025.[13]

There are four elements to the Pathways Step 1 proposal:

- Element One - the Step 1 proposal recommends that the WEM Governing Body's role be elevated to "primary authority" for issues that apply to WEIM or EDAM. A proposal comes to the Governing Body first for review and approval, and if approved (by majority vote) is placed on a consent agenda for the CAISO Board of Governors. The CAISO Board of Governors has the option to simply approve the consent agenda item or to remove the matter from the consent agenda for a full discussion of the proposal. In either case, a majority vote in favor of the proposal would be required for approval. The "applies to" test for establishing the scope of rules within the CAISO Board of Governors and WEM Governing Body's previously shared joint approval authority remains unchanged under the Step 1 governance changes now in effect. Thus, under the primary authority framework, the determination of whether the WEM Governing Body has primary authority would be made using the same "applies to"

[13] https://www.caiso.com/documents/apr-2-2025-letter-order-accepting-tariff-amendment-pathways-step-1-er25-542.pdf.

test that has been in place for several years under the previous joint authority governance model. The shift from joint to primary authority would thus impact only the process the two bodies follow for initial consideration and approval of a proposal.

- Element Two - modifies the current dispute resolution process to include a dual-filing option. As generally described in Question 8 above, the governance structure for the western energy markets includes a multi-step dispute resolution process if there is an instance where one body votes in favor of a proposal within their shared authority and the other body votes against it. The process requires the proposal to be remanded back to CAISO staff for additional public stakeholder proceedings designed to develop a revised proposal that would then come back to the two bodies for review and approval. If both bodies do not approve the revised proposal, the revised proposal could not move forward for filing at FERC, except in a circumstance where the CAISO Board of Governors finds, by unanimous vote "that exigent circumstances exist such that a tariff amendment is critical to preserve reliability or to protect market integrity." In that event, a proposal approved only by the CAISO Board of Governors may be filed with FERC, and the WEM Governing Body would have the right to prepare a written statement or opinion stating its position on the proposal that would be included with the filing. The Step 1 governance changes retain the general structure of this previously existing dispute resolution process, including the CAISO Board of Governor's "exigent circumstances" authority, but has now added a "dual-filing" option as a second means for moving forward when the CAISO Board of Governors and WEM Governing Body are unable to agree on a single proposal for

FERC to consider. This dual-filing approach is modeled on a dual-filing process that ISO New England has developed for circumstances where the New England Power Pool Participants Committee supports an alternative to a tariff amendment approved by ISO New England. The WEM Governing Body and CAISO Board of Governors could each approve a differing proposal, and the two proposals would be filed at FERC as "coequal" proposals in a single document, with neither option presented as preferred over the other. FERC has the authority to approve either proposal, or potentially adopt elements of each proposal, using the just and reasonable standard set forth in Section 205 of the Federal Power Act. This dual-filing option is not available unless and until all steps in the dispute resolution process have been exhausted, including the remand to the stakeholder process to develop a revised single proposal for both bodies to consider. This requirement is intended to drive all parties towards a single proposal, wherever possible, with the dual-filing option serving only as a last resort if consensus cannot be reached. FERC accepted changes to the market tariff to enable this "dual-filing" option consistent with the Step 1 proposal in April 2025.[14]

- Element Three - augmenting language in the Charter for WEIM and EDAM Governance relating to consideration of the public interest. As part of the development of the Step 1 proposal, a group of Western state regulators, including California regulators, worked together with public advocate representatives to develop language that could be added to the Charter specifically to reinforce the importance of considering the interests of consumers across the WEIM and EDAM footprint and respecting state

[14] https://www.caiso.com/documents/apr-2-2025-letter-order-accepting-tariff-amendment-pathways-step-1-er25-542.pdf.

- and local regulatory authority. This language is now included in the Charter.
- Element Four - is the trigger for the Pathways Step 1 Proposal to take effect. The Launch Committee adopted criteria that would need to be met before the Step 1 governance changes would become effective. The changes would take effect when two conditions are satisfied: (1) execution of EDAM implementation agreements by utilities representing non-CAISO Balancing Authority Area load that is equal to or greater than 70 percent of CAISO Balancing Authority Area load; and (2) geographic diversity among the non-CAISO participants beyond PacifiCorp, the Balancing Authority of Northern California and Los Angeles Department of Water & Power, such that it includes at least one additional non-California entity each from the Northwest and the Southwest. These criteria were met on July 1, 2025, thereby triggering the effectiveness of the Step 1 governance change.

16. Q. WHAT IS THE STATUS OF THE PATHWAYS STEP 1 RECOMMENDATION?

A. The Step 1 governance changes are now in effect for all matters in the market tariff that apply to WEIM or EDAM. Pathways Step 1 was approved by the WEM Governing Body and the CAISO Board of Governors pursuant to their joint authority in August 2024. The changes necessary to the market tariff to effectuate the dual-filing option were accepted by FERC in April 2025. As of July 1, 2025, EDAM implementation agreements have been executed by PacifiCorp, Portland General Electric, the Balancing Authority of Northern California, the Los Angeles Department of Water & Power, Turlock Irrigation

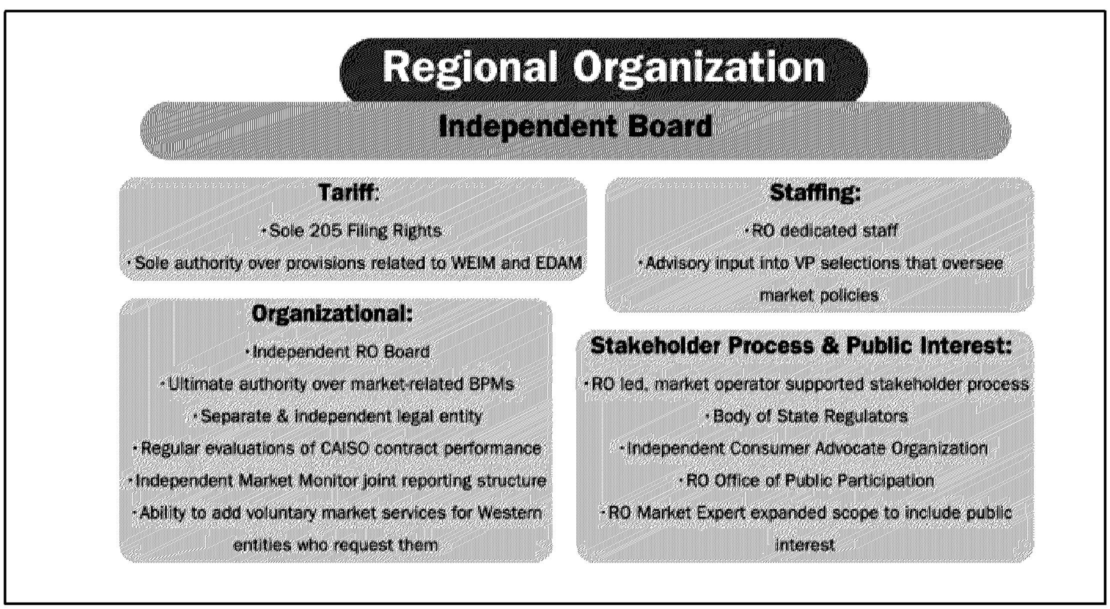
District, Imperial Irrigation District, and the Public Service Company of New Mexico. Collectively, these entities satisfy trigger criteria required by the Step 1 proposal.

17. Q. WHAT CHANGES DID PATHWAYS RECOMMEND AS STEP 2?

A. The proposal is two-fold: (1) create a new Regional Organization as a small organization with an independent policy-making board with *sole authority* over the WEIM and EDAM services that CAISO will continue to operate (referred to as "Option 2.0"); and (2) once in place, the Regional Organization would initiate a feasibility analysis on the potential steps for future evolution of the Regional Organization. The list of specific recommendations is included as the "Pathways Initiative Proposal Recommendations" in the final document, finalized in November 2024.[15] Figure 2 is a visual representation of the structure proposed for Step 2.

Figure 2

Pathways Step 2 Structure



[15] https://www.westernenergyboard.org/wp-content/uploads/Pathways-Initiative-Step-2-Final-Proposal.pdf.

Unlike the Step 1 changes however, Step 2 required a change in California law to enable California electric corporations to participate in energy markets governed by the Regional Organization and for CAISO to operate those markets on behalf of the Regional Organization.

18. Q. WHAT IS THE STATUS OF THE PATHWAYS STEP 2 RECOMMENDATIONS?

A. In early 2025, the Pathways Initiative Launch Committee established a Formation Committee comprised of a subset of its members to focus on development of the new Regional Organization as an independent corporation, consistent with the Step 2 proposal. Work continues to develop foundational documents and processes in order to stand up the Regional Organization. The Formation Committee provides monthly public updates and maintains a webpage hosted by the Western Interstate Energy Board with documents, presentations and recordings of the meetings.[16] The work of the Formation Committee has occurred in parallel with the effort to make necessary changes to California law to enable the Step 2 proposal.

A bill, Senate Bill 540 ("SB 540"), was introduced in the California Legislature on February 20, 2025, that would authorize CAISO and the electrical corporations whose transmission is operated by CAISO to use voluntary energy markets governed by an independent regional organization ("RO"), provided that specific requirements are met. Near the end of the legislative session, the bulk of the language from SB 540 was moved into Assembly Bill 825 ("AB 825"), with amendments which were supported by a large coalition of western energy industry organizations, labor, environmental

[16] https://www.westernenergyboard.org/wwgpi/.

and business groups. AB 825 was overwhelmingly passed in both the Senate and the Assembly on September 13, 2025.[17] The bill was then signed into law by California Governor Gavin Newsom on September 19, 2025. The bill enables the CAISO Board of Governors and the California Public Utilities Commission to take certain steps over the coming years, in coordination with the ongoing activities of the Pathways Initiative, in furtherance of establishing an independent RO.

19. Q. HOW DOES CAISO SEPARATE ITS RELIABILITY COORDINATOR FUNCTION FROM ITS BALANCING AUTHORITY RESPONSIBILITIES?

A. CAISO's RC West is the Reliability Coordinator of record for 25 balancing authorities and 40 transmission operators in the West. It oversees compliance with federal and regional grid reliability standards and can determine measures to prevent or mitigate system emergencies in day-ahead or real-time operations. RC West is overseen by the RC West Oversight Committee, comprised of representatives from the participating balancing authorities and transmission operators. There is a dedicated Director and team performing Reliability Coordinator functions. A dedicated webpage offers information and documents related to RC West.[18]

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[17] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202520260AB825.
[18] https://www.caiso.com/market-operations/products-services/rc-west.

<u>Stakeholder Process</u>

20. Q. PLEASE PROVIDE AN OVERVIEW OF CAISO'S STAKEHOLDER PROCESS.

A. CAISO maintains an open, transparent, and inclusive stakeholder process to support the development of market design and transmission planning policies. Meeting notices, documents, presentation and stakeholder comments are all posted on specific policy webpages, to ensure public access to all relevant information. Meeting notices are announced in advance and recorded to promote consistent engagement.

Through collaboration with a broad range of stakeholders—including market participants, utilities, regulatory agencies, industry organizations, and other interested parties—CAISO incorporates diverse perspectives and expertise. This inclusive approach is essential for the successful development and implementation of efficient market design, business practices, and infrastructure planning.

Through this public process, CAISO staff works closely with stakeholders to identify key issues and collaboratively develop policy solutions. These efforts culminate in formal proposals presented to the CAISO Board of Governors and the WEM Governing Body for approval.

Policy Initiative Lifecycle

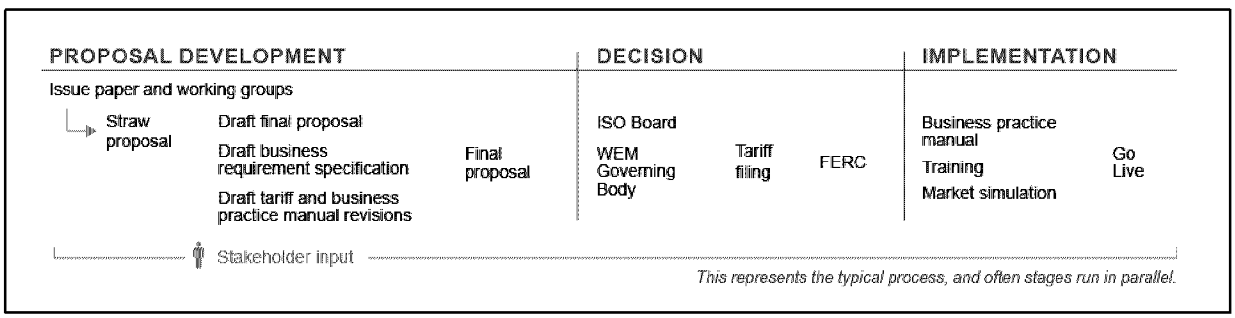
The typical lifecycle of a stakeholder policy initiative, illustrated in Figure 3, consists of three main phases: Proposal Development, Decision Making and Approval and finally Implementation.

It begins with identifying and prioritizing critical issues by convening stakeholder working groups and workshops to analyze data, explore business scenarios, define guiding principles, and draft problem statements. This collaborative phase is iterative and results in the development of several key documents: an issue paper, a straw proposal, a draft final proposal, and a final proposal.

As proposals evolve, CAISO staff work with stakeholders to draft tariff language as appropriate. Once finalized, the proposed tariff changes are submitted to FERC for approval, enabling implementation of the new policy.

Figure 3

CAISO Policy Initiatives – Stakeholder Process



A defining characteristic of CAISO's stakeholder process is its fully open, public, and transparent model. Any interested stakeholder may participate equally in the development of market and transmission planning policies—without the need for standing committees or designated member representation. Rather than being driven by formal membership structures, CAISO initiatives are issue-focused and inclusive.

To advance market policy changes, CAISO employs a mix of staff-led sessions, stakeholder presentations, and expert speakers. This collaborative approach ensures a wide range of perspectives contribute to mutually beneficial outcomes. Stakeholders may provide input during public discussions as well as through submission of written comments which shape ongoing iterative proposal development.

21. Q. HOW ARE INITIATIVES SELECTED FOR STAKEHOLDERING?

A. CAISO policy initiatives originate from a variety of sources, including:

- Federal Energy Regulatory Commission (FERC) orders
- Recommendations from the CAISO Department of Market Monitoring or the Market Surveillance Committee
- Issues identified through day-to-day market operations
- Feedback and requests submitted by stakeholders

Each year, CAISO conducts a *Policy Catalog and Roadmap* process to identify and prioritize new policy initiatives based on stakeholder requests and input. During this process, stakeholders are invited to submit policy proposals for consideration. These proposals are evaluated based on their alignment with CAISO's Strategic Plan, stakeholder interest, feasibility, urgency, and available CAISO resources. The outcome of this process is the *Policy Roadmap*, a multi-year work plan that outlines the policy initiatives CAISO intends to pursue over the next three years.

22. Q. WHO CAN PARTICIPATE IN THE STAKEHOLDER PROCESS?

A. Participation in CAISO's stakeholder process is open to all. There are no fees, membership requirements, or specific affiliations needed; any individual or organization with an interest is welcome to engage and contribute.

23. Q. CAN COMMISSION STAFF PARTICIPATE DIRECTLY IN THE STAKEHOLDER PROCESS?

A. Yes. Any government agency or regulatory body is welcome to participate. CAISO also frequently provides policy initiative updates to the BOSR, which is made up of regulators across Western states, for their questions and input. BOSR members and staff track relevant and active market policy development with the support of dedicated staff at WIEB, as described in Question 10, and they may also participate in dedicated training sessions provided throughout the year.

24. Q. HOW ARE WRITTEN COMMENTS USED IN THE STAKEHOLDER PROCESS?

A. CAISO values stakeholder feedback and actively incorporates written comments throughout the policy development process. After each major iteration of a proposal—such as the issue paper, straw proposal, and draft final proposal—CAISO invites stakeholders to submit written comments.

These comments serve several important purposes:

1. **Expanded Input**: They allow stakeholders to provide detailed explanations, insights, or concerns that may not have been fully addressed during meetings.

2. **Transparency**: Written comments clarify which entities support or oppose specific elements of a proposal, offering visibility to both CAISO staff and other market participants as these comments are publicly posted.
3. **Constructive Alternatives**: Stakeholders can suggest modifications or propose alternative solutions to improve or evolve policy proposals.
4. **Broader Review**: Comments are available for review by the Department of Market Monitoring, the Market Surveillance Committee, and the WEM Governing Body or CAISO Board of Governors, helping inform their considerations and decisions.

CAISO staff carefully review, summarize, and respond to stakeholder comments as part of the iterative proposal development process and stakeholder meetings. This feedback plays a critical role in shaping the evolving and final policy design that is ultimately presented for approval.

Finally, written comments and verbal comments are welcome during the decisional process for the WEM Governing Body or CAISO Board of Governors. There are opportunities for public comment at each of their open meetings, where both verbal and written comments may be considered.

__The EDAM Implementation Process and Exit Process__

25. Q. PLEASE DESCRIBE THE EDAM ONBOARDING PROCESS AND TIMELINE.

A. Each entity that seeks to become an EDAM entity and enable participation within its BAA must first execute an EDAM Implementation Agreement. The *pro forma* EDAM Implementation Agreement is Appendix B.31 of the CAISO tariff.

CAISO has divided the EDAM onboarding process into six separate tracks with their own scope, deliverables, milestones, meeting structures, and workshops:[19]

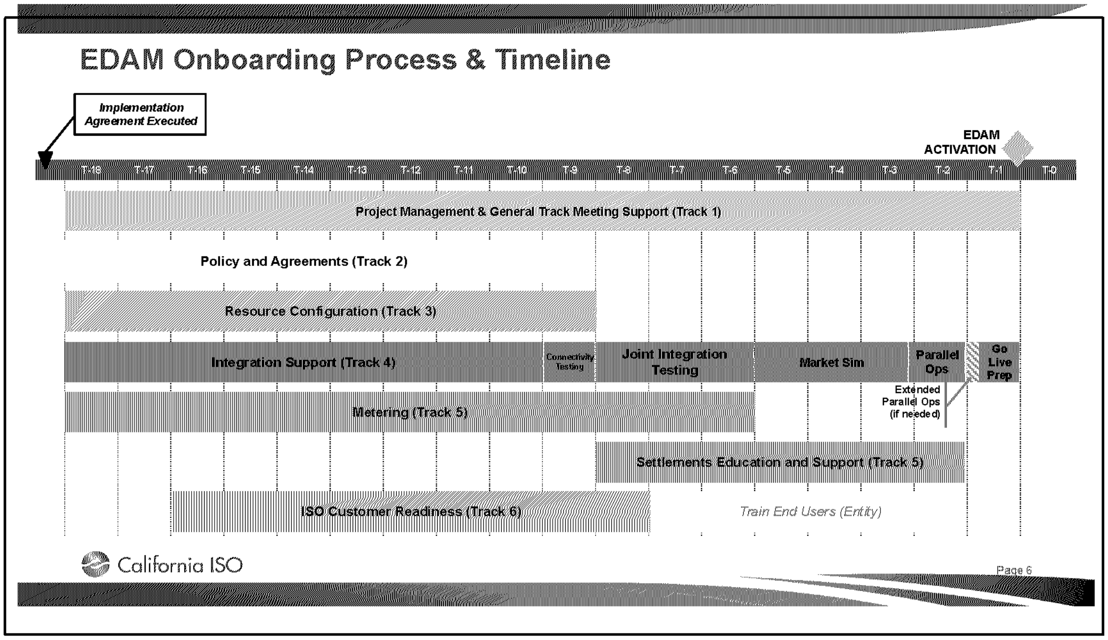
- Track 1 Planning and Project Management
- Track 2 Policy, Legal, Contracts, and Access
- Track 3 Resource Configuration
- Track 4 Systems Integration and Testing
- Track 5 Metering and Settlements
- Track 6 Training and Readiness

The EDAM implementation process takes approximately 18 months. As illustrated in Figure 4, many of the activities run in parallel.

[19] *See* https://www.westerneim.com/Documents/edam-onboarding-overview.pdf.

Figure 4

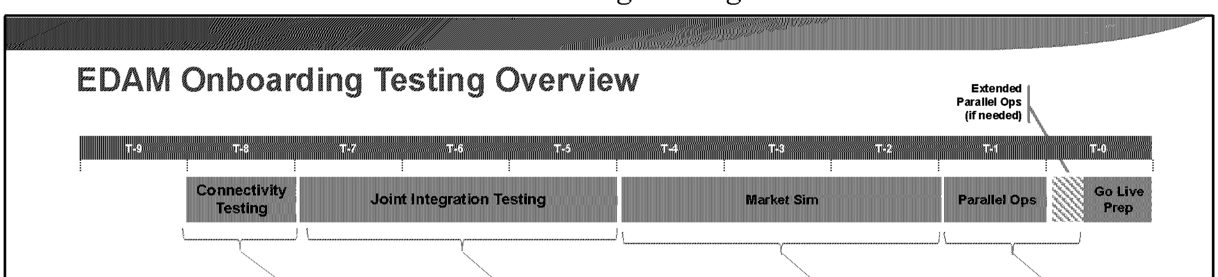
EDAM Onboarding Process & Timeline



A more detailed depiction of the onboarding testing process is provided in Figure 5.

Figure 5

EDAM Onboarding Testing Process



	Connectivity Testing	Joint Integration Testing		Market Simulation	Parallel Ops
Duration	2 – 4 weeks	3 months		3 months	4 - 6 weeks
Primary Objective	Verify EDAM Entities systems and users are able to access the ISO systems.	*Integration Test:* New EDAM Entities and ISO verify sending and receiving necessary data to and from the ISO	*Functional Test:* New EDAM Entities verifies all systems and payloads function. SME training occurs during this time.	Through structured and unstructured scenarios, ISO and New EDAM Entities jointly verify market functions through to settlements.	Final validation of the EDAM market with production data. Finalize readiness criteria.
Environment	Map Stage	Map Stage	Map Stage	Map Stage	Stage
Who?	Technical Team	Technical Team Business SMEs	Business SMEs	New EDAM Entities, ISO, Existing ISO participants and stakeholders	New EDAM Entities and ISO only

26. Q. PLEASE EXPLAIN THE PROCESS, TIMELINE, AND COSTS TO EXIT EDAM.

A. Participation in EDAM by a balancing authority ("BA") is entirely voluntary. A BA can terminate its participation in EDAM with a six-month notice and without exit fees. The BA can elect to remain in the WEIM when it exits EDAM or to also exit the WEIM at the same time or a later date. The terms applicable to exit from the WEIM are the same as EDAM, *i.e.*, a BA can terminate its participation with a six-month notice and without exit fees.

27. Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, STACEY CROWLEY, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: October 21, 2025

Stacey Crowley

APRIL GORDON

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy

Extended Day-Ahead Market Energy Supply Plan Amendment
Docket No. 25-10___

Prepared Direct Testimony of

April Gordon

Introduction

1. Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is April Gordon. I am the Executive Director of Financial Planning and Procurement for the California Independent System Operator ("CAISO"). My business address is 250 Outcropping Way, Folsom, California 95630. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra") (together, "NV Energy").

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS EXECUTIVE DIRECTOR OF FINANCIAL PLANNING AND PROCUREMENT?

A. As the Executive Director of Financial Planning and Procurement, I oversee the development of CAISO's Grid Management Charge ("GMC") ensuring that rates are aligned with actual service costs and comply with cost-causation and ratemaking principles. This involves conducting cost-of-service studies, coordinating with stakeholders, and integrating operational and financial data to support transparent, accurate, and equitable charge settings. My role ensures that the GMC reflects both the efficient use of CAISO resources and the financial sustainability of the organization. Additionally, I am responsible for directing the organization's budget preparation and management, leading long-term financial planning, and managing corporate vendor procurement and contract administration.

3. Q. WOULD YOU PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE?

A. I hold a Bachelor's degree in Business Administration with a concentration in Accountancy and a Master of Business Administration from California State University, Sacramento. At CAISO, I advanced through several leadership roles - serving as Director (2016–2023), Manager (2014–2016), and Financial Analyst (2010–2014) - before assuming my current position. Prior to joining CAISO, I was a Senior Accountant at the California Association of Hospitals and Health Systems and an Accountant at Enterprise Resource Group.

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony, I provide an overview of:

- Anticipated Extended Day-Ahead Market ("EDAM") participation costs both for implementation and ongoing; and
- CAISO's overall financial health and financial statements.

<u>EDAM Administrative Costs</u>

5. Q. DOES CAISO CHARGE A FEE FOR ONBOARDING EDAM BALANCING AUTHORITIES?

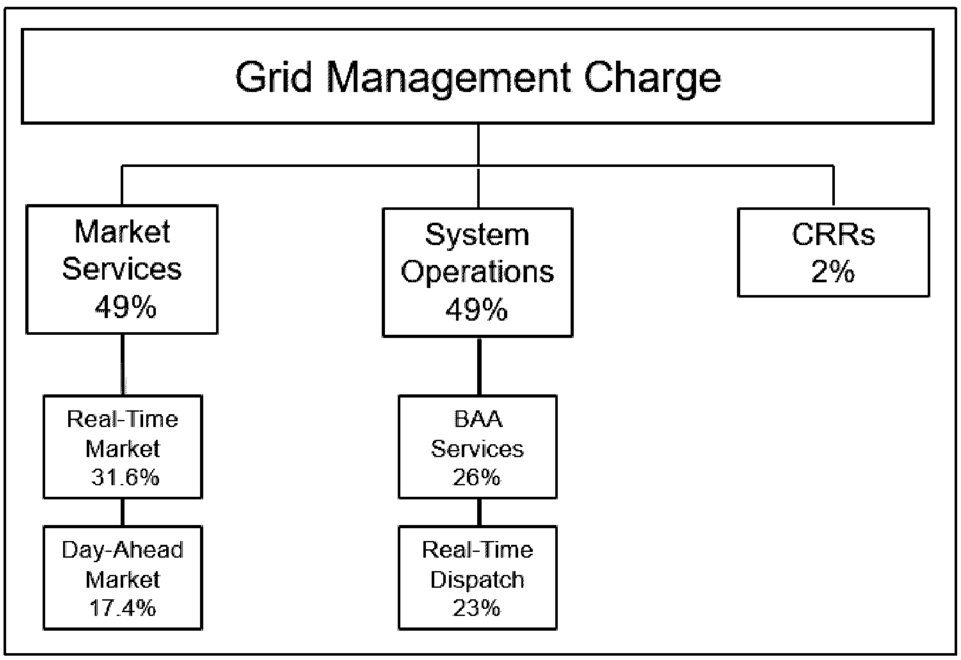
A. Yes. The EDAM Entity Implementation Agreement spells out the EDAM Entity implementation fee structure. Specifically, the cost will be based on CAISO's cost of service. The actual cost to onboard an EDAM Entity will vary depending on the size, complexity and length of onboarding. Typical onboarding expenses are expected to be between $1.2 million and $1.4 million accrued over an estimated 18-month onboarding timeline. An initial $300,000 deposit will be collected upon signing the Implementation Agreement. If the deposit exceeds the actual cost incurred, CAISO will refund the excess amount including any interest accrued on the remaining deposit. If the actual cost exceeds the deposit, additional deposits in $300,000 increments will be required. This fee structure aligns with CAISO's existing cost recovery practices for similar services.

6. Q. CAN YOU DESCRIBE HOW CAISO RECOVERS ITS ADMINISTRATIVE COSTS?

A. CAISO recovers it administrative costs (also referred to as the net revenue requirement) primarily through its Grid Management Charge ("GMC") and other fees. These charges and fees are developed using results from a triennial cost-of-service study and applied to the annual revenue requirement. Both the study and the revenue requirement development processes are vetted through a public stakeholder process in accordance with CAISO's tariff. The cost-of-service study uses activity-based costing to evaluate how resources and staff time are allocated across CAISO's service categories. A key outcome of the study is the development of cost category percentages, which are applied to the annual revenue requirement in order to establish GMC rates. The three service categories include market services, system operations,[1] and congestion revenue rights services (CRRs). This approach ensures that costs are aligned with services provided, and that rates adhere to cost-causation and sound ratemaking principles. Figure 1 below depicts the categories that make up the GMC.

Figure 1

Grid Management Charge Services



The annual revenue requirement is comprised of CAISO's operations and maintenance budget, debt services, cash funded capital, other costs and revenues, and operating cost reserve adjustment. The first three components of the revenue requirement represent CAISO's annual cost to operate. The

[1] The system operations category and charge code will be retired as of 12/31/2025. The systems operations real-time dispatch and system operations balancing authority area services categories and charge codes will replace the retired code effective 1/1/2026. Reference the 2023 cost-of-service study for additional information: https://stakeholdercenter.caiso.com/InitiativeDocuments/Revised-Draft-Final-2023-Cost-of-Service-Study-and-2024-2026-Grid-Management-Charge-Update.pdf.

other cost and revenue components include the supplemental revenues received from sources other than the GMC; these revenues reduce the overall revenue requirement. These other revenues include items such as, but not limited to, the Reliability Coordinator funding requirement, Western Energy Imbalance Market ("WEIM") administrative charges, intermittent resource forecasting fees, generator interconnection project fees, and fees for operating the California-Oregon Intertie Path. The operating cost reserve adjustment is a resulting credit or debit from the prior full year's operations plus a mechanism to provide for an operating reserve and debt service reserve.

Once the net revenue requirement (or GMC revenue requirement) is determined, the service category percentages, as calculated through the most recent cost-of-service study, are applied against the revenue requirement. The service category costs are then divided by forecasted volumes to establish the annual GMC rates. Forecasted volumes are typically gathered by analyzing historical usage trends, adjusting for expected changes such as market growth, policy shifts, or customer behavior, and incorporating input from subject matter experts. The rates and fees are charged to market participants and other customers as services are rendered.

The WEIM administrative costs are comprised of the market services real-time charge and the real-time portion of the system operations charge. When EDAM launches in 2026, the EDAM administrative costs will be comprised of the market services charge and the new system operations real-time dispatch charge. CAISO has clarified that once an EDAM entity begins participating in

EDAM, it will no longer pay WEIM administrative fees, as the EDAM administrative fees cover both day-ahead and real-time services.

7. Q. PLEASE DESCRIBE THE ONGOING COSTS THE COMPANIES EXPECT TO INCUR TO JOIN THE EDAM.

A. EDAM participants can expect to be assessed the market services charge per MWh and the system operations real-time dispatch charge per MWh, as well as some supplemental fees that include but are not limited to the monthly SCID fees and bid segment fees.

For the initial four years of EDAM operations, CAISO proposed and FERC approved a transitional ramp-in of load-based charges. The ramp-in would only apply to load volumes and not to supplier volume-based charges to avoid providing any suppliers with a competitive advantage in the market. The basis of the load-based ramp-in level would be determined by the year the EDAM participant joins. The ramp-in percentages are year 1 (5 percent), year 2 (25 percent), year 3 (50 percent), and year 4 (75 percent); by year 5 of EDAM's operations, all participants will pay 100 percent of their load and supply charges.

The table below in Figure 2 outlines how CAISO's GMC cost allocation is applied across different service participation types. It breaks out charges by Market Services (Day-Ahead and Real-Time), System Operations (Balance Authority Area Services and Real-Time Dispatch), and Congestion Revenue Rights ("CRR") Services. The percentages show how much of the GMC each participation type is responsible for in 2026, with EDAM entities ramping up over five years (from 5% to full 100% load participation). The table demonstrates the progressive allocation of costs as entities increase their level of market participation, ensuring that charges are aligned with the scope of services used.

Figure 2

Grid Management Charge Cost Allocation

	Market Services Charge Code*				System Operations Charge Code**				
	Day Ahead Market		Real-Time Market		Balance Authority Area Services		Real-Time Dispatch		Congestion Revenue Rights Services Charge Code
Service Participation Type	Load 30%	Supply 70%	Load 30%	Supply 70%	Load 41%	Supply 59%	Load 41%	Supply 59%	
Full BAA Participation	100.0%				100.0%				100.0%
WEIM Participation (1)			64.5%				46.9%		
EDAM Participation (Year 1; 5% load ramp-in) (2)	1.8%	35.5%	3.2%	64.5%			2.3%	46.9%	
EDAM Participation (Year 2; 25% load ramp-in) (2)	8.9%	35.5%	16.1%	64.5%			11.7%	46.9%	
EDAM Participation (Year 3; 50% load ramp-in) (2)	17.8%	35.5%	32.2%	64.5%			23.5%	46.9%	
EDAM Participation (Year 4; 75% load ramp-in) (2)	26.6%	35.5%	48.4%	64.5%			35.2%	46.9%	
EDAM Participation (Year 5; 100% load ramp-in) (2)	100.0%						46.9%		

For all participation types the $/MWh is based on load and supply.

*The Market Service volumes include day ahead load schedule, day ahead schedule, 15 minute market, and instructed imbalance energy volumes. The discount is only applied to the day ahead load schedule volumes. The volume split is 30% Load / 70% Supply.

**The System Operations volumes include generation, import, load, and export volumes. The discount is only applied to the load volumes. The volume split is 41% load / 59% supply.

(1) WEIM GMC Market Services component amount is calculated based upon Real-Time Market (RTM) instructed imbalanced energy in relationship to base schedules submission excluding transfer resources.

(2) EDAM GMC Market Services component amount is calculated on Day-Ahead Market schedules plus any RTM instructed imbalanced energy in relationship to the Day-Ahead schedules.

For exploratory purposes, CAISO calculated NV Energy's estimated EDAM year 5 costs using their market services and system operations volumes incurred in WEIM. The estimate considers expected participation informed by executed agreements, publicly stated commitments, and bilateral engagement with potential participants. The estimate also assumes a forecasted revenue requirement and accounts for the loss of WEIM fees as participants move from WEIM to EDAM. Using the aforementioned assumptions, CAISO estimated NV Energy's BAA level annual GMC cost attributed to EDAM is estimated to be approximately $15.5 million beginning in year 5 of EDAM's operations; as this is a BAA level estimate, the actual cost will be recovered in part from NV Energy's participating

Schedule Coordinators. This estimate only represents the ongoing GMC charge and is separate from CAISO's implementation charge, which is captured in the Implementation Agreement and the EDAM project implementation costs.

8. Q. WHAT IS CAISO'S CREDIT RATING AND DOES CAISO MAKE ITS FINANCIAL STATEMENTS PUBLICLY AVAILABLE?

A. CAISO's current credit rating from the three major rating agencies is Standard and Poor's Global Ratings A+, Fitch Ratings A+, and Moody's A1. In July 2014, Standard and Poor's Global Ratings raised CAISO's issuer credit rating and senior secured rating to A+, citing strong and predictable financial performance.[2] CAISO has retained that high rating ever since.

In 2024, Fitch Ratings noted, "CAISO's ratings and Stable Outlook reflect the stable revenues and cash flows derived from its Federal Energy Regulatory Commission (FERC) regulated tariff structure, strong grid management charge (GMC) coverage ratios, and the integral role played by the company in achieving state and federal energy policy goals with regard to reliability, competition, renewable energy and environmental issues."[3]

CAISO's financial statements, including its FERC Form No. 1 Report and Quarterly Financial Reports, can be found at: https://www.caiso.com/about/financials.

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[2] https://www.caiso.com/documents/californiaisogetscreditratingsbump_a_plus.pdf.

[3] https://www.streetinsider.com/Press+Releases/Fitch+Affirms+California+ISOs+IDR+at+A%2B%3B+Outlook+Stable/10738212.html.

9. Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, APRIL GORDON, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: October 21, 2025

April Gordon

HUGO FRECH

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy

Extended Day-Ahead Market Energy Supply Plan Amendment
Docket No. 25-10___

Prepared Direct Testimony of

Hugo Frech

INTRODUCTION

1. Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Hugo Frech. I am the Chief Information Security Officer and Executive Director of IT Infrastructure for the California Independent System Operator ("CAISO"). My business address is 250 Outcropping Way, Folsom, California 95630. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra") (together, "NV Energy").

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS CHIEF INFORMATION SECURITY OFFICER AND EXECUTIVE DIRECTOR OF IT INFRASTRUCTURE?

A. As Chief Information Security Officer, I am responsible for ensuring the confidentiality, integrity, and availability of our organization's data, so that it remains secure, unaltered, and accessible when needed. This means protecting sensitive information from threats, maintaining trust, and ensuring that the data we rely on is dependable for decision-making and service delivery. Part of my role includes developing strategies to manage risk, preparing for potential disruptions, and ensuring compliance with regulatory standards. As Executive Director of IT Infrastructure, I oversee the technology foundation that powers our operations. This includes the networks, systems, and platforms that enable our employees to serve the public effectively every day. My focus is on ensuring these systems are reliable, resilient, and capable of supporting both current needs and future growth, so that essential services remain uninterrupted and accessible to the people who depend on them.

3. Q. WOULD YOU PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE?

A. I have more than three decades of experience in Information Technology, beginning my career in the United States Marine Corps as an aviator and Information Systems Officer. I have been part of CAISO since 2003 leading our information technology departments. I am a Certified Information Systems Security Professional ("CISSP") and have completed an advanced cybersecurity certificate program at Stanford University, as well as the FBI Cyber Academy in Sacramento. My academic background includes a Bachelor of Arts in Philosophy from California State University, San Bernardino, and a Master of Science in Telecommunications Systems Management from National University.

CYBER SECURITY PROGRAM

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony, I provide an overview of CAISO's Cyber Security Program and discuss the resiliency of the markets to cyber security threats.

5. Q. PLEASE BRIEFLY DISCUSS CAISO'S CYBER SECURITY PROGRAM.

A. CAISO's Information Security Program is strategically structured to ensure a proactive and resilient operation. We have cultivated a strong culture of compliance and cyber awareness across the organization, recently completing two consecutive audits of our compliance with the North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") standards with zero compliance violations, which is a clear indicator of a strengthened control environment and effective risk mitigation. Through the modernization of our technology infrastructure and strategic partnerships with both state and federal agencies, we have significantly reduced our vulnerability exposure footprint.

Our program adheres to NERC CIP Standards, is aligned with the National Institute of Standards and Technology ("NIST") Cybersecurity Framework and is benchmarked against broader industry and regulatory standards to ensure accountability and continuous improvement. These efforts directly support our organizational strategic plans, ensuring a secure, scalable, and resilient IT platform that protects mission-critical operations and aligns with national cybersecurity priorities.

6. Q. PLEASE DISCUSS THE RESILIENCY OF THE MARKETS TO CYBER SECURITY THREATS.

A. CAISO has implemented a defense-in-depth strategy to ensure resilience across all layers of its cybersecurity architecture. This approach uses multiple technologies and controls to prevent a single point of failure from compromising system reliability, market availability, or data confidentiality.

CAISO has deployed advanced proven security technologies at the edge of its network to protect against external threats. These advanced capabilities are purpose-built appliances to defend against sophisticated external threats. Access to internet-facing systems is tightly restricted to only what is necessary for business operations. Encryption safeguards both CAISO and market participant data, and multifactor authentication secures remote access for staff. We block unauthorized software that is not specifically identified and listed in our maintained "allowlist," and we monitor configurations to detect unsafe changes and perform continuous vulnerability scanning.

We leverage threat intelligence to help stay ahead of emerging risks. We receive and evaluate daily, weekly, and monthly intelligence briefs from federal and state sources. As the Reliability Coordinator for the western United States, we lead many cyber security information-sharing teams to discuss risk landscape and mitigation strategies to prepare for advanced persistent threats. Our Information Security Operations Center operates 24/7, ensuring continuous monitoring and rapid response to emerging threats.

A critical component of our cybersecurity program is preparing the organization to effectively detect, respond, and recover in alignment with the NIST cybersecurity framework. We lead NERC GridEx reliability coordinator planning with a focus on mitigating physical and cyber attacks across the North American grid. This facilitates training and testing for hundreds of asset owners, critical infrastructure sectors, and agency partners at federal, state, and local level.

While technology investments are essential, we recognize that no program can guarantee the prevention of every incident. To that end, CAISO has established a monthly incident response drill program focused on cyber security response. These exercises are conducted in collaboration with Business Continuity and our Incident Command System.

7. Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, HUGO FRECH, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: October 21, 2025

Hugo Frech

JOHN TSOUKALIS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy

Extended Day-Ahead Market Energy Supply Plan Amendment
Docket No. 25-10___

Prepared Direct Testimony of

John Tsoukalis

I. Introduction and Qualifications

1. Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is John Tsoukalis. I am a Principal at The Brattle Group. My business address is 1800 M Street NW, Suite 700N, Washington, DC 20036.

2. Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting this direct testimony before the Public Utilities Commission of Nevada ("Commission") on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra") (together the "Companies" or "NV Energy").

3. Q. PLEASE DESCRIBE THE BRATTLE GROUP.

A. The Brattle Group is a consulting firm with a professional staff in excess of 400 individuals and offices in North America, Europe, and the Asia-Pacific region. The firm was founded in 1990 in Cambridge, Massachusetts. We have a large electric power practice focused on market, regulatory, and financial matters in the industry. We are an industry leader and provide planning support as well as expert testimony on electricity rate design, transmission system expansion and coordination, analysis of the benefits and risks of investments or ownership of electricity assets and contracts, and analysis of wholesale electricity markets. We also advise clients on the design, pricing, and risk management of wholesale and retail services, and provide testimony on these matters before regulatory agencies for electric utilities and other market participants.

4. Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I am an energy economist and regulatory expert with an educational background in economics and over 10 years of experience advising clients in the electric power industry. For multiple clients, I have assessed the benefits, costs, and operational impacts of participation in regional wholesale markets in the western U.S. and in the southeastern U.S. I have analyzed and modeled the power system in various parts of North America, advised clients on market entry decisions, regulatory and policy matters, market design, transmission investment decisions, rate design, and compliance with market power rules. In addition, I have assisted clients in comprehensive organizational strategic planning efforts.

I have provided testimony before the Federal Energy Regulatory Commission ("FERC") on several occasions, before several state public utility commissions, the Alberta Utilities Commission, and before a U.S. District Court.

I hold a Bachelor of Arts in Economics from Washington and Lee University, a Master of Science in Economics from The Barcelona Graduate School of Economics, and a Master of Science in Economic Analysis from the Universitat

Autònoma de Barcelona. My statement of qualifications is attached as **Exhibit Tsoukalis-Direct-1**.

5. Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY.

A. In my testimony, I analyze the customer benefits of three potential market options for the Companies and assess the drivers of those benefits for their customers. The three market participation options are: (1) remain in the Western Energy Imbalance Market ("WEIM"), (2) join the Extended Day-Ahead Market ("EDAM"), which implies also remaining in the WEIM, and (3) join Markets+.

6. Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A. I reviewed three cases: (1) where NV Energy remains in the WEIM (the business-as-usual ("BAU") case), (2) where NV Energy joined EDAM and (3) where NV Energy joined Markets+. The benefits quantified include adjusted production cost savings, short-term wheeling revenues, market congestion revenues, and bilateral trading margins. I find that NV Energy's net system costs are reduced by $93.1 million per year by joining EDAM, compared to remaining only in the WEIM, and are increased by $7.3 million moving from WEIM to Markets+.

II. <u>Cases Modeled, Market Results, and Analysis</u>

7. Q. PLEASE EXPLAIN WHAT MARKET FOOTPRINTS AND OPTIONS WERE STUDIED FOR THE COMPANIES AND THE RATIONALE FOR THEIR SELECTION.

A. I analyzed the effects of three market participation scenarios on the Companies' net system costs. This includes a case where NV Energy remains in the WEIM (BAU case), as it represents NV Energy's existing market membership. In the BAU case, all day-ahead transactions are conducted bilaterally as NV Energy does today. Bilateral transactions can be long-term contracts for resources in NV Energy's Balancing Authority Area ("BAA") serving load in other BAAs, which I model for any long-term contracts that are known publicly or to NV Energy, or bilateral transactions can be short-term transactions that use available transmission rights or that pay for short-term transmission service, which are both captured in my analysis. I also analyzed two day-ahead market participation scenarios where NV Energy joins either EDAM or Markets+. In all three cases, the market participation assumptions for all the other utilities in the Western Electric Coordinating Council ("WECC") remain the same, which serves to isolate the impact of NV Energy's market participation rather than measure the impact of other entities' market membership decisions.

The market membership assumed for all other WECC entities represents each entity's currently announced commitment to one market or the other, announced leaning towards one market, or each entity's likely participation based on public statements of preference towards either EDAM or Markets+.

- **EDAM Footprint**: The modeled EDAM footprint includes the California Independent System Operator ("CAISO"), Los Angeles Department of Water and Power ("LADWP"), Portland General Electric ("PGE"), the Balancing Authority of Northern California (modeled as "BANC" and the Sacramento Municipal Utility District ("SMUD")), Public Service Company of New Mexico ("PNM"), PacifiCorp (modeled as their two separate BAAs, PAC-East ("PACE") and PAC-West ("PACW")), the Imperial Irrigation District ("IID"), the Turlock Irrigation District ("TIDC"), the Idaho Power Company

("Idaho Power"), and Seattle City & Light ("SCL"). Participation in the EDAM implies participation in the WEIM for real-time energy imbalance.

- **Markets+ Footprint**: The modeled Markets+ footprint includes the entities who have announced their intent to join Markets+ and are currently funding Phase 2 of Markets+. This includes the Bonneville Power Administration ("BPA"), Tacoma Power ("TPWR"), PowerEx ("BCHA" or "PowerEx"), Puget Sound Energy ("PSEI"), Chelan County Public Utility District ("CHPD"), Grant Count Public Utility District ("GCPD"), Arizona Public Service ("AZPS"), Salt River Project ("SRP"), Tucson Electric Power ("TEPC"), El Paso Electric ("EPE"), and the Public Service Company of Colorado ("PSCO"). In addition, I assume that the resources and load in the portion of the SPP Regional Transmission Organization ("RTO") that is in the WECC are co-optimized with the Markets+ footprint.[1] This includes the Western Area Power Administration ("WAPA") Upper Great Plains West ("WAUW") BAA and the WAPA Rocky Mountain BAA ("WACM"), which includes the Loveland Area Projects ("LAP") and the Colorado River Storage Projects ("CRSP") systems.[2]
- **WEIM Footprint**: I modeled utilities that have not announced a decision, leaning, or preference for either day-ahead market as maintaining their current or planned market participation status, which for many utilities is remaining in the WEIM only and not joining either day-ahead market. This includes Avista Power ("AVA"), Black Hills (which includes Black Hills Power and

[1] The SPP RTO plans to expand into the WECC in April 2026. *See* https://www.spp.org/news-list/spp-first-rto-to-operate-in-both-interconnections-with-tariff-approval/.

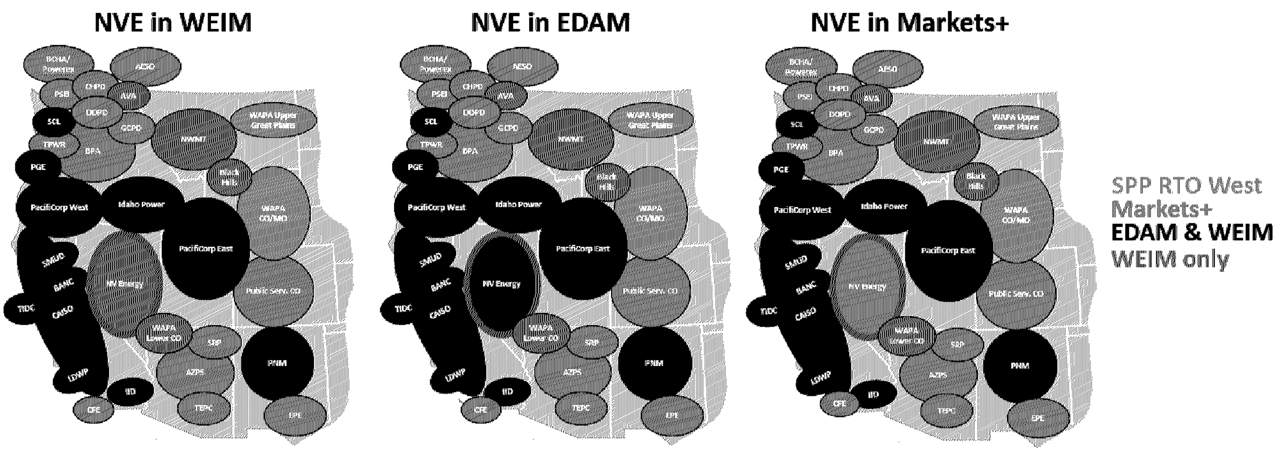
[2] The early Markets+ design documents indicated that "Markets+ will optimize and coordinate with SPP RTO at some point in the future." *See* Southwest Power Pool, Markets+, *Market Design and Transmission Availability Sessions Working Draft,* August 1, 2022, p. 6, accessed at https://spp.org/documents/67619/marketdesign_workingdraft_v0.1.pdf. Co-optimization between Markets+ and SPP RTO may not occur at the start of Markets+, planned for 2027, but I assume that functionality will be implemented by 2032 (the year studied in my analysis).

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

Cheyenne Light Fuel & Power, who have announced their intention to join the WEIM), Northwestern Energy ("NWMT"), and the WAPA Lower Colorado ("WALC") BAA.

Figure Tsoukalis Direct-1 provides an illustration of the market participation assumptions by utility in the WECC, for all the three cases I study in my analysis.

FIGURE TSOUKALIS DIRECT-1: MODELED CASES AND MARKET FOOTPRINTS



8. Q. WHAT YEAR DOES YOUR STUDY ANALYZE AND MODEL?

A. I model the year 2032 and reflect the anticipated resource mix, load, and transmission rights for NV Energy and all other utilities in the WECC in that year. The study year of 2032 aims to reflect the first decade of markets operations, representing both a year in the near-future with relatively certain resource plans and load projections, and a year far enough into the future to capture known changes in the WECC.

9. Q. PLEASE EXPLAIN WHAT BENEFIT METRICS YOU ANALYZED.

A. I analyze several types of customer savings and potential costs created by NV Energy's participation in a regional market through various metrics calculated in my analysis:

- **Adjusted Production Cost ("APC") Savings**: a commonly-used metric in the industry that accounts for the change in fuel and operating costs for NV Energy's resources, including start-up costs, and the change in sales revenues for NV Energy's resources and its purchased power costs. I analyze each of those three components separately – production costs, sales revenue, and purchased power costs – and sum the three to create the APC metric. A reduction in APC for NV Energy can be driven by a reduction in operation of its resources due to the availability of low-cost purchases in the market or by an increase in operation of its resources to execute profitable market sales.
- **Short-Term Wheeling Revenues**: accounts for revenues received by NV Energy through the sale of short-term transmission service for the use of its transmission system by the utility's merchant operations or by third parties. This metric focuses only on short-term transmission service, as my analysis assumes long-term contracts for transmission service will remain in place, and NV Energy will continue to collect the revenue from long-term contracts, under either day-ahead market and in the BAU case.
- **Market Congestion Revenues**: accounts for the surplus congestion revenues allocated to NV Energy under either day-ahead market. This includes surplus day-ahead congestion, collected through either EDAM or Markets+, and surplus real-time congestion through the WEIM or Markets+. This metric captures ***surplus*** congestion revenue because congestion costs and revenues associated with NV Energy's load and resources are already captured in the

APC metric. The APC accounts for the fact that all NV Energy generation resources will be paid their locational price in the markets and that all NV Energy load will pay their locational price, both of which include congestion charges or credits. Therefore, the APC already accounts for the congestion settlements directly related to NV Energy's load and resources. The market congestion revenue metric is an estimate of the surplus amount of congestion collected by the market administrators and allocated back to market participants.

- **Bilateral Trading Margins**: accounts for the margins earned on bilateral sales or purchases through the NV Energy BAA. In non-market settings, such as the day-ahead timeframe in the BAU case, utilities and third party traders earn margins on sales and purchases of power, which are captured by this metric.

In addition to these customer savings and benefit metrics, there are other customer benefits created by day-ahead markets that I do not quantify. These include a reliability benefit to NV Energy's customers, due to the diverse resource mix available through a regional market and the load diversity in each market. The diversity of a large regional market footprint increases the likelihood that other market members will have surplus generation in times when NV Energy is facing scarcity conditions, and vice versa. There are potential environmental benefits to participation in regional day-ahead markets, due to the reduction in curtailment of renewable resources and greenhouse gas emissions, as well as potentially other planning and operational benefits due to participation in a regional day-ahead market that I have not analyzed. I do not analyze the administrative costs of implementing or operating either day-ahead market in my analysis.

10. Q. WHAT RESULTS DID YOUR ANALYSIS FIND?

A. I find that NV Energy's net system costs fall $93.1 million in the case that it joins EDAM and increase $7.3 million in the case that it joins Markets+, relative to the BAU case where NV Energy stays only in WEIM. EDAM produces net benefits in adjusted production cost, surplus market congestion revenues, and short-term wheeling revenues, while I find Markets+ produces net benefits for NV Energy customers in the allocation of surplus market congestion revenues, but a cost increase in all the other metrics. I discuss the drivers of these results in the next questions.

FIGURE TSOUKALIS DIRECT-2: SUMMARY OF NV ENERGY SYSTEM COSTS AND NET BENEFIT OF MARKET PARTICIPATION BY METRIC ($ MILLIONS)

Metric	BAU	EDAM	Markets+
Adjusted Production Cost	$558.5	$524.3	$566.4
Short-Term Wheeling Revenues	$12.8	$40.5	$0.4
WEIM Congestion Revenue	$1.1	$4.8	$0.0
EDAM Congestion Revenue	$0.0	$56.0	$0.0
Markets+ RT Congestion Revenue	$0.0	$0.0	$2.6
Markets+ DA Congestion Revenue	$0.0	$0.0	$25.7
Bilateral Trading Revenue	$43.7	$15.3	$29.6
Net System Cost	$500.9	$407.7	$508.2
Benefit Relative to BAU Case		$93.1	-$7.3

Note: Net system cost is the sum of Adjusted Production Cost – all other metrics as all other metrics listed are revenues NV Energy collects.

The benefits I calculate of joining either day-ahead market are conservative for several reasons. For example, the model overstates the efficiency of bilateral markets, resulting in lower costs in the BAU case than would likely be the case in reality. The model assumes all balancing authorities have optimal security constrained unit-commitment and dispatch in the BAU case, which overstates dispatch efficiency and then creates the opportunity for more bilateral trading than likely exists in the WECC today. In addition, that model uses weather-normalized loads, monthly average fuel prices without daily volatility, and does not contain transmission outages, which reduces the likelihood of scarcity events. Day-ahead markets like EDAM and Markets+ are more valuable in periods of abnormal load, fuel price volatility, and during outage conditions, and thus my analysis is missing some of the benefit that would accrue to NV Energy customers during periods of system stress. The BAU case also does not reflect the limited liquidity of bilateral market trading during challenging market conditions, which would make the BAU case more costly in comparison to the other cases. The model is hourly, not sub-hourly, which misses some of the value of sub-hourly functions that markets like EDAM and Markets+ provide, such as sub-hourly re-dispatch and managing energy imbalance and reserves. For these reasons, I anticipate that the realized benefits of day-ahead market participation for NV Energy customers will be much larger than what I calculate in this study.

11. Q. PLEASE EXPLAIN THE BENEFIT/COST DRIVERS OF JOINING EDAM.

A. I find that the major drivers of NV Energy's net system benefit in joining EDAM are:

- **APC Benefits:** NV Energy is able to make low-cost purchases in the spring to reduce their own more expensive gas generation, and is able to make more advantageous sales of their gas generation and renewables in the fall and winter especially, driving over $34 million in net benefit to NV Energy.
- **Market Congestion Revenues:** NV Energy has transfer capability with four major EDAM participants (CAISO, LADWP, PacifiCorp, and Idaho Power),

each with diverse resource mixes compared to each other and to NV Energy. This creates significant EDAM transfer revenue for NV Energy, and surplus congestion revenue in the case they join EDAM. Total market congestion revenues increase by nearly $60 million per year compared to the BAU case.

- **Short-Term Wheeling Revenues and Bilateral Trading Revenues**: NV Energy has one of the lowest modeled short-term wheeling charges (or open access transmission tariff ("OATT") charge) of the entities that can sell directly to the desert southwest Markets+ participants. CAISO and LADWP have short-term wheeling charges exceeding $12/MWh while NV Energy's modeled charge is only about $7.6/MWh. As a result, I see short-term wheeling revenues increase almost $28 million for NV Energy in the EDAM case since the model finds it optimal to wheel-through excess renewables during midday hours from CAISO and LADWP through NV Energy to the Arizona utilities in Markets+. I discuss this dynamic more later and its impact on NV Energy's market participation benefits in EDAM. On the other hand, trading margins on short-term bilateral trades fall by nearly $30 million per year when NV Energy joins EDAM, as market transactions supersede short-term bilateral transactions.

12. Q. PLEASE EXPLAIN THE BENEFIT/COST DRIVERS OF JOINING MARKETS+.

A. I find that the major drivers of NV Energy's net system loss from joining Markets+ are:

- **APC Benefits:** While joining Markets+ increases NV Energy's market sales revenues, leaving the WEIM causes a larger net loss. Net purchase costs and production costs rise relative to the BAU case, especially in the spring when in WEIM NV Energy has access to low-cost market purchases, allowing it to keep from running expensive gas generation. Because of how similar the southwest resource mix is to NV Energy's, and how little transfer capability exists between the southwest of Markets+ and the northwest, the Markets+ case sees a net $8 million increase in NV Energy's APC.

- **Market Congestion Revenues:** NV Energy accrues $28.3 million per year of surplus market congestion revenues in Markets+, a significant increase over the BAU case.
- **Short-Term Wheeling Revenues and Bilateral Trading Revenues:** NV Energy sees a decline of $12.4 million in short-term wheeling revenues in Markets+ compared to the BAU case as sales to the Arizona utilities become hurdle-free in the market. However, NV Energy continues to earn nearly $30 million per year in bilateral trading margins in Markets+.

13. Q. PLEASE EXPLAIN THE ADJUSTED PRODUCTION COST BENEFIT OF JOINING EACH DAY-AHEAD MARKET.

A. **Figure Tsoukalis DFigure** tsoukalis direct-3 below shows a detailed breakdown of the APC metric for all three cases, the BAU case, the EDAM case, and the Markets+ case. **Figure tsoukalis direct-3** contains two tables, the first compares the BAU and EDAM cases, to illustrate the impact of NV Energy joining EDAM on the APC metric. The second table compares the BAU and Markets+ cases, to illustrate the impact of joining Markets+. As I explained before, the APC has three components: (1) the production cost, (2) purchased power costs, and (3) sales revenues. The rows of each table in **Figure tsoukalis direct-3** show the details of each of these components. The first row (labeled as [1] in the tables) shows the impact on production volume and cost between the BAU and day-ahead market participation scenario in that table. Rows [2] and [3] show the impact on purchased power volume and costs from joining the day-ahead market. Row [2] shows day-ahead purchased power and row [3] shows real-time purchased power. Rows [4] and [5] show sales revenues, which is the revenue NV Energy makes from selling its own generation into other balancing authorities. Row [4] shows day-ahead sales revenues and row [5] shows real-time sales revenues. These components all sum together to create a total system impact in row [6], which is the sum of production [1], day-ahead purchases [2], real-time purchases [3] minus day-ahead sales [4] and real-time sales [5].

The two tables below are broken into three panels. The first, labeled "GWh," shows the volume of production, purchases, and sales in each case. The second panel, labeled "$/MWh," shows the weighted average cost of production, purchases, and sales. The third panel, labeled as "Total ($1000s/year)," shows the total dollar impact on production cost, purchased power costs, and sale revenues in each case. The bottom row of the third panel shows the total change in APC between the two cases, which is the total APC benefit/cost to NV Energy's customers from joining the day-ahead market.

FIGURE TSOUKALIS DIRECT-3: ADJUSTED PRODUCTION COST BY CASE

EDAM Case - Adjusted Production Cost Comparison for NEVADA

Cost Components			GWh BAU	GWh EDAM	GWh Difference	$/MWh BAU	$/MWh EDAM	$/MWh Difference	Total ($1000s/Year) BAU	Total ($1000s/Year) EDAM	Total ($1000s/Year) Difference
Production Cost	(+)	[1]	50,949	50,379	**-570**	$12.95	$12.87	-$0.09	659,963	648,232	-$11,731
Purchased Power Costs	(+)										
Day-Ahead Market + Bilateral		[2]	3,275	7,571	**4,297**	$24.95	$13.81	-$11.14	81,710	104,536	$22,826
Real-Time Market		[3]	3,684	1,819	**-1,865**	-$3.94	$18.06	$21.99	-14,505	32,856	$47,361
Market Sales Revenue (Negative = Cost)	(-)										
Day-Ahead Market + Bilateral		[4]	3,677	6,432	**2,755**	$16.89	$32.11	$15.22	62,081	206,512	$144,432
Real-Time Market		[5]	3,304	2,411	**-893**	$32.27	$22.73	-$9.54	106,626	54,803	-$51,823
Total Cost *(Negative Difference = Benefit)*		[6]	**50,928**	**50,928**	**0**	**$10.97**	**$10.30**	-$0.67	558,461	524,309	-$34,152
% Change in APC											*-6.1%*

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [4] - [5] as sales are revenues, not costs. A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.

Markets+ Case - Adjusted Production Cost Comparison for NEVADA

Cost Components			GWh BAU	GWh Markets+	GWh Difference	$/MWh BAU	$/MWh Markets+	$/MWh Difference	Total ($1000s/Year) BAU	Total ($1000s/Year) Markets+	Total ($1000s/Year) Difference
Production Cost	(+)	[1]	50,949	53,858	**2,909**	$12.95	$13.14	$0.18	659,963	707,513	$47,551
Purchased Power Costs	(+)										
Day-Ahead Market + Bilateral		[2]	3,275	4,527	**1,253**	$24.95	$21.98	-$2.97	81,710	99,535	$17,824
Real-Time Market		[3]	3,684	1,941	**-1,744**	-$3.94	$13.17	$17.10	-14,505	25,551	$40,056
Market Sales Revenue (Negative = Cost)	(-)										
Day-Ahead Market + Bilateral		[4]	3,677	7,140	**3,463**	$16.89	$29.33	$12.44	62,081	209,387	$147,307
Real-Time Market		[5]	3,304	2,259	**-1,045**	$32.27	$25.13	-$7.15	106,626	56,770	-$49,856
Total Cost *(Negative Difference = Benefit)*		[6]	**50,928**	**50,928**	**0**	**$10.97**	**$11.12**	$0.16	558,461	566,441	$7,980
% Change in APC											*1.4%*

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [4] - [5] as sales are revenues, not costs. A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.

- **APC Benefits in EDAM**: NV Energy customers see a net APC cost reduction of $34.1 million per year in EDAM driven by three dynamics: (1) production costs decrease $11.7 million due to a reduction in gas generation of about 700 GWh (offset by ~100 GWh increase in solar generation due to falling curtailments); (2) net purchase power costs increase $70.2 million as NV Energy purchased power volumes increase 4.3 TWh in the day-ahead market, while the average day-ahead purchase price falls about $11.1/MWh due to the availability of low-cost power in EDAM; and (3) sales revenues increase $92.6 million from NV Energy's ability to sell more power into the market by almost 2 TWh (day-ahead and real-time combined) and earn higher average revenues of about $15/MWh for market sales.

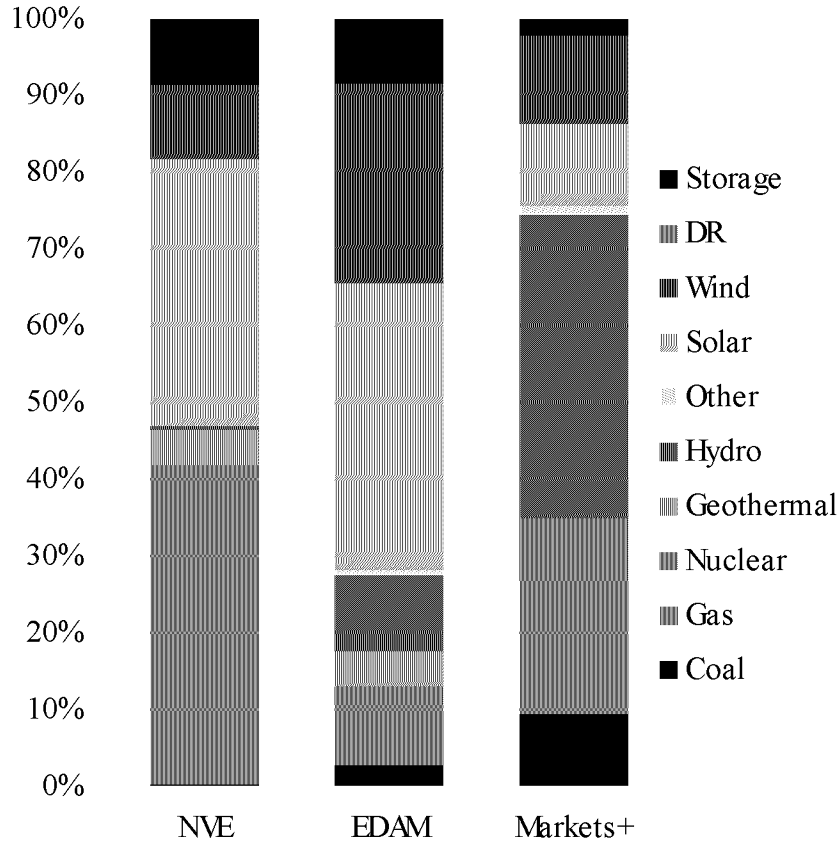
- **APC Loss in Markets+**: NV Energy sees a net APC loss of almost $8 million per year in Markets+ driven by three dynamics: (1) production costs increase

$47.6 million due to an increase in gas generation of about 2,100 GWh (renewable curtailments also fall about 800 GWh); (2) net purchase costs increase $57.9 million mostly driven by an increase in the average real-time purchase cost of over $17/MWh, which is due to NV Energy's departure from the WEIM that offers abundant low-cost power from excess solar in California and excess wind in PACE; and (3) sales revenues increase $97.4 million from higher day-ahead market sales that earn about $12.4/MWh more on average in Markets+ than in the BAU case.

14. Q. PLEASE EXPLAIN HOW THE RESOURCE DIVERSITY WITHIN THE MARKET FOOTPRINTS AND TRANSFER CAPABILITY TO THE OTHER MEMBERS OF THE MARKETS DRIVE THE APC BENEFIT FOR NV ENERGY CUSTOMERS.

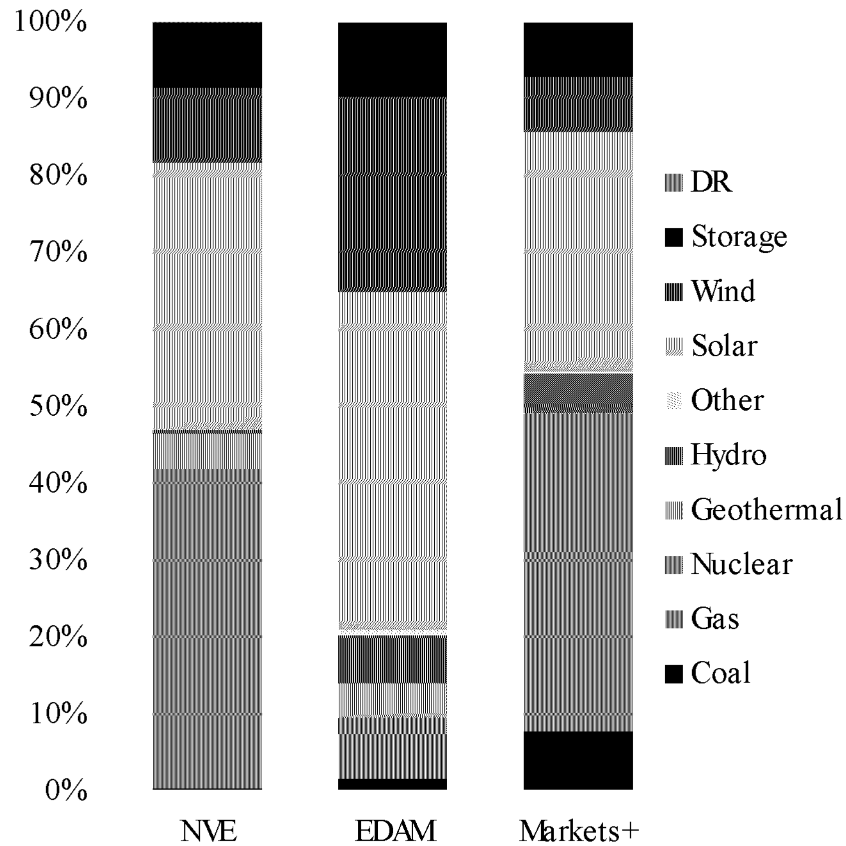
A. The diversity of resources in the market footprint creates the opportunity for economic transactions that can drive down costs for customers. For example, if one member of a market has low-cost, efficient gas generators, another has abundant solar resources, and a third has abundant wind resources there will be a lot of opportunity to trade excess low-cost power among these three entities and avoid operating higher-cost resources. **Figure Tsoukalis Direct-4** shows the diversity of generation in the BAU case in NV Energy's system and across the two market footprints. The figure illustrates that there is significant resource diversity in both of the expected market footprints relative to NV Energy, as EDAM contains significantly more wind than NV Energy and Markets+ contains significant hydro generation.

FIGURE TSOUKALIS DIRECT-4: SHARE OF NV ENERGY'S GENERATION VS. THE GENERATION OF ALL MARKET PARTICIPANTS



However, **Figure Tsoukalis Direct-4** only shows part of the story, as adequate transmission interconnection between market participants is necessary to fully capture the value of resource diversity in the market footprint. NV Energy has large interconnection with several neighboring BAAs that are expected to participate in either EDAM or Markets+, including PACE, CAISO, Idaho Power, LADWP, AZPS, and SRP. NV Energy has a smaller interconnection with BPA, which is expected to participate in Markets+. **Figure Tsoukalis Direct-5** shows the generation share in each market footprint weighted by NV Energy's total transfer capability ("TTC") to each member in the two markets, compared to NV Energy's generation. Therefore, the figure shows an approximation of the diversity of resources that each market could deliver to NV Energy customers using the transmission capability available within each market, assuming NV Energy joined that market. For example, PGE and SCL have hydro resources, but there is no direct interconnection between those two utilities and NV Energy, so that generation is not included in **Figure Tsoukalis Direct-4** in the EDAM column. That does not mean that EDAM cannot use the transmission provided by other members, such as PacifiCorp, Idaho Power, or CAISO, to sell excess hydro generation from PGE and SCL to NV Energy. The EDAM will be able to execute those types of transactions when its economic to do so, but **Figure Tsoukalis Direct-4** attempts to visualize how transfer capability and resource diversity interact to impact the benefit NV Energy customers can achieve from market sales and purchases in either footprint. In Markets+, BPA and other expected members in the Pacific Northwest have large hydro resources, as shown in **Figure Tsoukalis Direct-4**, but the transfer capability between NV Energy and the Pacific Northwest is relatively small, so the amount of hydro shown in **Figure Tsoukalis Direct-4** for Markets+ is also relatively small.

FIGURE TSOUKALIS DIRECT-5: SHARE OF NV ENERGY'S GENERATION VS. THE GENERATION OF MARKET PARTICIPANTS CONNECTED TO NV ENERGY (WEIGHTED BY NV ENERGY'S TRANSFER CAPABILITY TO EACH PARTICIPANT)



Note: Generation for EDAM includes PacifiCorp, CAISO, Idaho Power, and LADWP, which are the expected EDAM participants that directly connect to NV Energy. Generation for Markets+ includes AZPS, SRP, and BPA, which are the expected Markets+ participants that connect to NV Energy. Generation totals are from the BAU case before NV Energy joins either market. Generation is weighted for each participant by NV Energy's total transfer capability with that entity to reflect their ability to access each resource type. The storage bar indicates storage discharging.

Figure Tsoukalis Direct-5 helps tell the story of why NV Energy customers experience a reduction in production cost benefits in EDAM. The availability of low-cost wind in the EDAM footprint (mostly in PACE and the CAISO BAAs) complements NV Energy's resource mix of mostly solar and gas. Similarly, the abundance of solar generation in EDAM (mostly in California) provides a diversity benefit with Nevada solar as the production profiles of solar resources in the two geographies vary over the course of the day.

15. Q. PLEASE EXPLAIN THE SEASONAL PATTERN OF APC BENEFIT FOR NV ENERGY CUSTOMERS.

A. I find that the largest driver of APC costs accruing to NV Energy customers is the availability of low-cost surplus renewable power. The expected EDAM and WEIM footprints contain the majority of the WECC's solar, wind, battery storage, and non-emitting generation by 2032. In the spring especially, this power is available for purchase in the market for nearly $0/MWh for large portions of the day. EDAM's ability to sell this power to NV Energy's loads and reduce NV Energy's use of more expensive gas generation drives the large APC benefit experienced in EDAM.

Figures Tsoukalis Direct-6 and **Tsoukalis Direct-7** illustrate the seasonal pattern of net APC benefit for NV Energy customers by breaking out the APC benefit by month for each market. The figures show the breakdown of the APC metrics into its three components—production cost, purchased power costs, and sales revenues. In the figures, a positive bar is a benefit for NV Energy customers, meaning a positive bar is a reduction in production cost or purchased power cost or an increase in sales revenue. In both markets, the drivers of APC benefits are similar across the year. In the summer, fall, and winter months, NV Energy increases its market sales in both day-ahead markets, which is partially offset by increased production costs. In the spring, NV Energy reduces its production and increases market purchases of low-cost power, mostly surplus solar from California. However, the figures illustrate that the springtime purchases are much larger in EDAM (**Figure**

Tsoukalis Direct-6) and create a larger APC savings for customers than in Markets+ (**Figure Tsoukalis Direct-7**). In Markets+, system costs actually increase in the spring months relative to the BAU case where NV Energy is in WEIM. This is due to the large impact excess solar generation from California (which is in WEIM) has on reducing the price of purchased power for NV Energy.

FIGURE TSOUKALIS DIRECT-6: NET APC BENEFIT BY MONTH
(EDAM CASE MINUS BAU CASE)

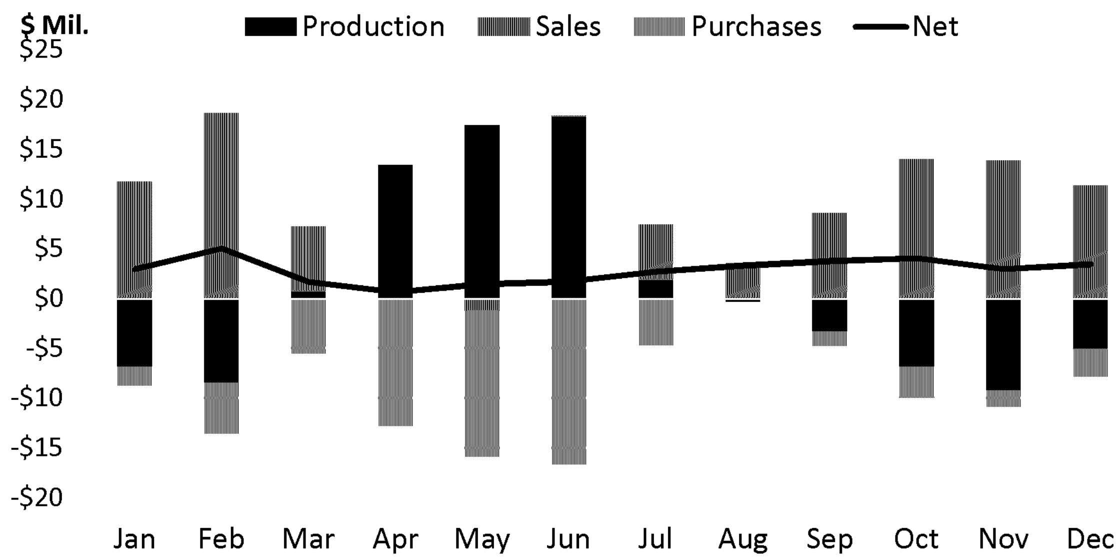
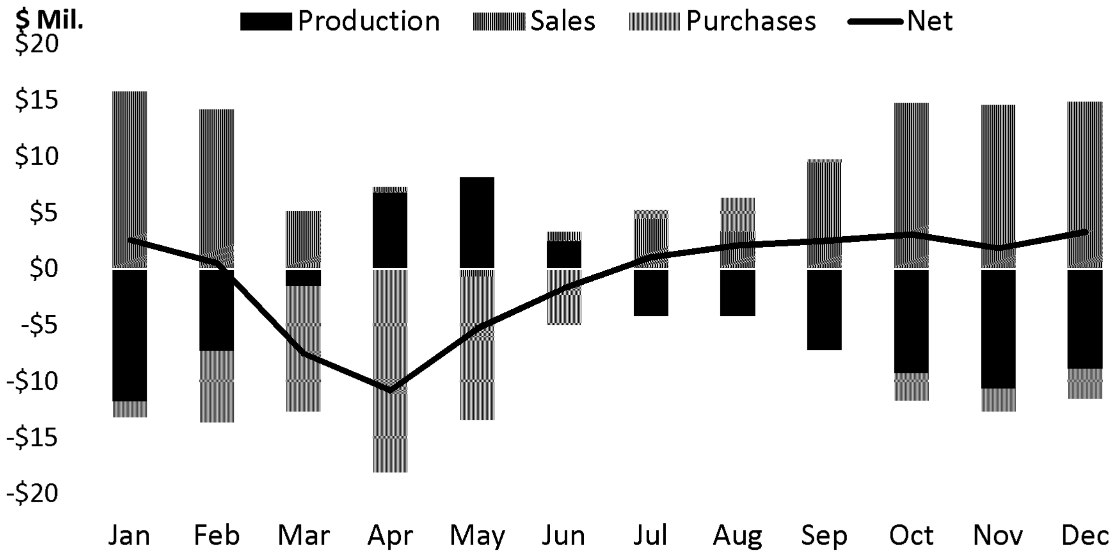


FIGURE TSOUKALIS DIRECT-7: NET APC BENEFIT BY MONTH (MARKETS+ CASE MINUS BAU CASE)



16. Q. HOW CAN DAY-AHEAD MARKET PARTICIPATION HELP NV ENERGY MANAGE PERIODS OF EXCESS SOLAR PRODUCTION?

A. Participating in a regional market allows NV Energy to import power from neighboring BAAs during the late afternoon and evening hours when solar production is ramping time, which is the time of day that can often be most challenging for system operators. This dynamic is especially prominent in EDAM, because California solar resources produce later into the afternoon and evening than Nevada solar resources. **Figures Tsoukalis Direct-8** and **Tsoukalis Direct-9** show the hourly production within the NV Energy BAA, imports into the BAA, and exports out of the BAA for the average day during spring months for the EDAM case and Markets+ case, respectively. In **Figure Tsoukalis Direct-8**, imports into the NV Energy BAA from CAISO and LADWP are shown as blue bars outlined in black and NV Energy's internal solar production is shown in yellow. The figure illustrates how NV Energy's solar production falls off quickly after hour beginning

4pm, while imports from California remain high into the next hour and through the evening. This is driven by California solar production stretching later into the day than Nevada solar and the large quantity of battery storage in California. The availability of low-cost power in the EDAM during the late afternoon and early evening helps balance the ramp down of its own solar, and defers the use of its thermal assets and battery storage into the evening hours. **Figure Tsoukalis Direct-9**, shows that imports into the NV Energy BAA from California are still prevalent in Markets+ during midday hours, but not in the same quantity as in EDAM and they do not extend as late into the evening hours as in EDAM.

FIGURE TSOUKALIS DIRECT-8: NV ENERGY AVERAGE HOURLY SYSTEM DISPATCH AND TRADING IN SPRING IN THE EDAM CASE

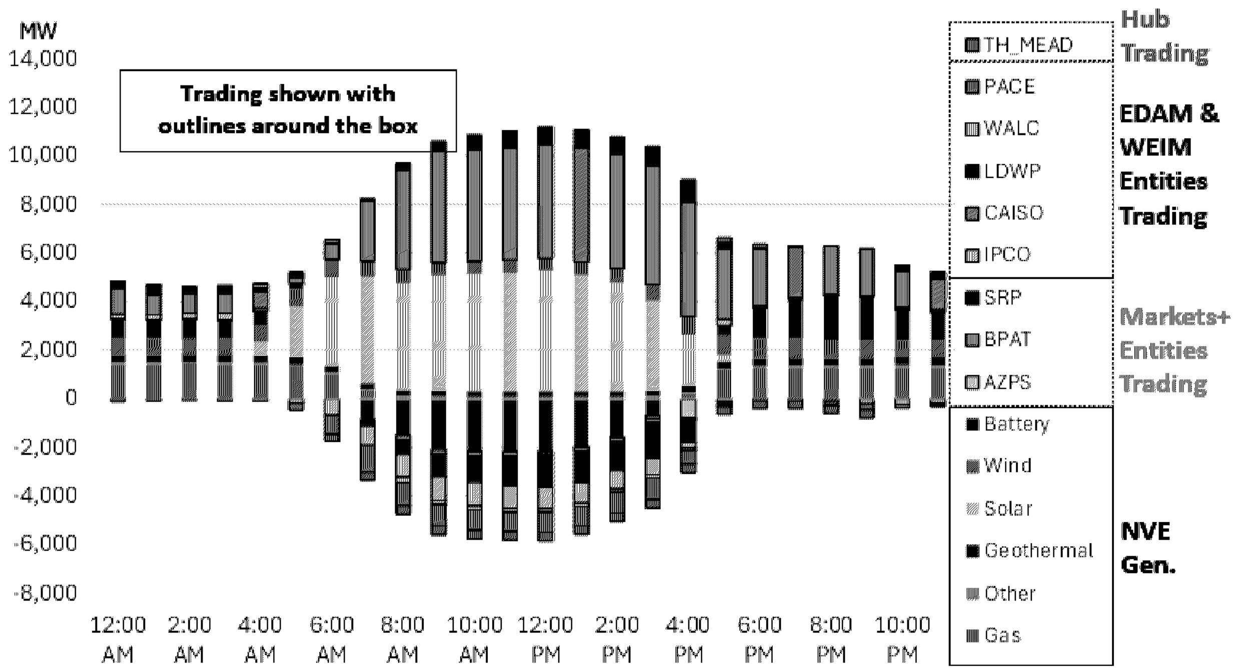
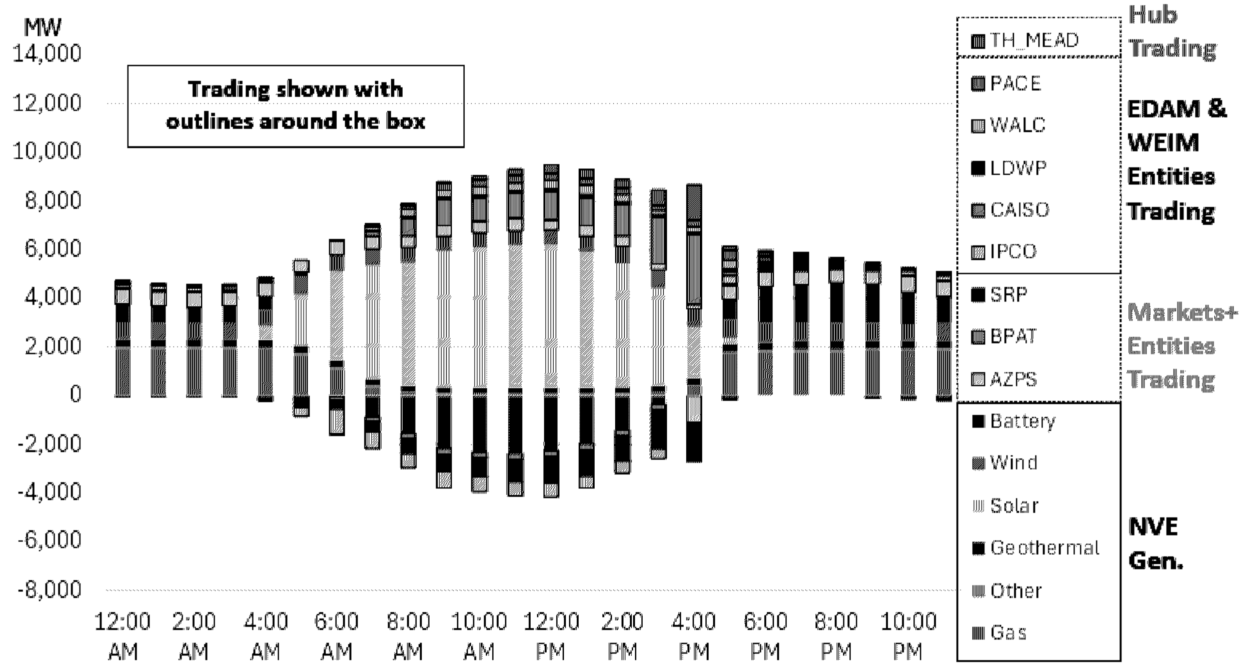


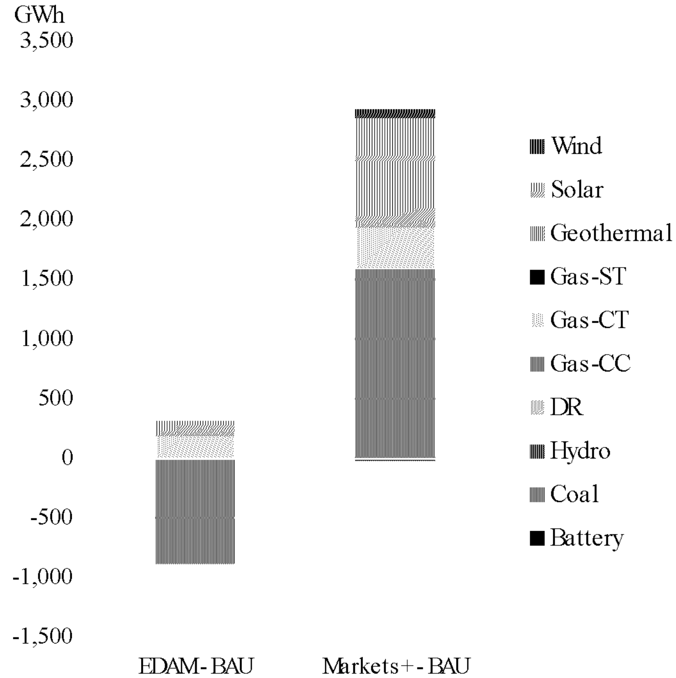
FIGURE TSOUKALIS DIRECT-9: NV ENERGY AVERAGE HOURLY SYSTEM DISPATCH AND TRADING IN SPRING IN THE MARKETS+ CASE



17. Q. HOW DOES DAY-AHEAD MARKET PARTICIPATION CHANGE THE GENERATION FROM NV ENERGY RESOURCES?

A. I find that both markets reduce the curtailment of NV Energy's solar resources. The change in generation in the EDAM and Markets+ cases, relative to the BAU, is visible in **Figure Tsoukalis Direct-10**. The EDAM reduces NV Energy gas generation by about 700 GWh while increasing solar generation about 100 GWh, and Markets+ increases NV Energy's gas generation about 2,100 GWh and solar generation about 900 GWh.

FIGURE TSOUKALIS DIRECT-10: CHANGE IN GENERATION FOR NV ENERGY'S SYSTEM RELATIVE TO THE BAU CASE BY RESOURCE TYPE



18. Q. **PLEASE EXPLAIN THE TRADING DYNAMICS YOU OBSERVE FOR NV ENERGY IN EACH MARKET.**

A. I find that the EDAM nearly doubles how much NV Energy trades with its neighbors relative to the BAU case, which is driven by NV Energy's significant interconnection and resource diversity with the other large EDAM members CAISO, LADWP, PacifiCorp, and Idaho Power. I also find that Markets+ increases NV Energy's trading volume by nearly 50 percent with neighboring utilities compared to the BAU case. **Figure Tsoukalis Direct-11** shows the total trading volume between NV Energy and neighboring entities in each market across all three market participation scenarios. This figure and **Figure Tsoukalis Direct-12** include only market transactions in EDAM, Markets+, or WEIM and short-term bilateral transactions, executed with existing transmission rights or short-term transmission service. These tables do not include transactions associated with long-term contracts between utilities across the WECC. For example, if a resource physically located in Nevada has a contract with a load-serving entity in CAISO, the power from that resource is not accounted for in this table as an export from NV Energy to CAISO.

FIGURE TSOUKALIS DIRECT-11: NV ENERGY TRADING VOLUME BY MARKET MEMBERSHIP (NOT INCLUDING HUB TRADING) (GWH)

Trade	BAU Case			EDAM Case			Markets+ Case		
	Imports	Exports	Total	Imports	Exports	Total	Imports	Exports	Total
Nevada Total	10,721	11,016	21,737	20,845	19,245	40,090	13,522	17,513	31,035
Entities in EDAM	9,364	7,790	17,154	19,776	13,432	33,208	5,868	5,381	11,248
Entities in Markets+	600	968	1,568	149	4,090	4,239	6,717	12,122	18,839
Entities in WEIM	757	2,259	3,015	920	1,723	2,643	937	10	947

Note: Trading totals are short-term trades only. They do not include resources located in the NV Energy BA that are contracted to other entities.

Figure Tsoukalis Direct-12 shows NV Energy's total trading volume with each of its neighboring BAAs across all three market participation cases. Consistent with **Figure Tsoukalis Direct-11**, the figure below shows how trading with the EDAM BAAs, CAISO, Idaho Power, LADWP, and PacifiCorp (the PACE BAA) increases significantly when NV Energy joins EDAM. In particular, imports from the CAISO BAA increase from approximately 5.6 TWh when NV Energy is in WEIM-only versus over 14 TWh when NV Energy joins EDAM. Similarly, when NV Energy joins Markets+, its trading with AZPS, SRP, and BPA increases significantly, with a corresponding decline in trading with the EDAM/WEIM members.

FIGURE TSOUKALIS DIRECT-12: TOTAL NV ENERGY TRADING BY COUNTERPARTY (GWH)

Trade	Market	BAUCase			EDAMCase			Markets+Case		
		Imports	Exports	Total	Imports	Exports	Total	Imports	Exports	Total
Nevada Total		11,610	11,631	23,241	21,091	20,543	41,633	14,608	17,539	32,148
CAISO		5,614	104	5,719	14,053	68	14,121	2,887	0	2,887
IPCO	EDAM	1,230	4,130	5,360	1,292	7,656	8,947	957	5,345	6,302
LDWP		918	195	1,114	2,068	612	2,680	361	0	361
PACE		1,601	3,361	4,962	2,363	5,097	7,460	1,663	36	1,699
AZPS		0	238	238	0	468	468	4,621	3,022	7,643
BPA	Markets+	349	493	842	105	356	461	918	2,087	3,006
SRP		251	236	487	44	3,265	3,310	1,178	7,013	8,191
WALC	WEIM	757	2,259	3,015	920	1,723	2,643	937	10	947
TH_MEAD	Hub	889	615	1,504	246	1,297	1,543	1,087	26	1,113

Note: Trading totals are short-term trades only. They do not include resources located in the NV Energy BA that are contracted to other entities.

19. Q. HOW DO YOU MODEL THE SEAMS BETWEEN EACH MARKET?

A. There are several different types of seams between utilities and markets represented in the model I used for this study, which reflect the different types of seams that currently exist in the WECC and will emerge as the two new day-ahead markets develop. The primary way I capture the inefficiencies created by seams is through the application of hurdle rates in the model for trades that take place outside of an organized market. For example, if a trade between two utilities is a $5/MWh hurdle rate, the model will limit trading between those utilities to hours when the total profit from the trades exceed $5/MWh.

- Market Trades: trades within one of the organized markets in the WECC, including the EDAM, Markets+, WEIM, the CAISO, or the SPP RTO West. These trades have no hurdle rate on them.
- Bilateral Trades: trades between two utilities that are not in any organized market. I represent different types of bilateral trades in the model, including block trades at the major hubs in the WECC and hourly utility-to-utility

trades. Block trades at the major hubs have a lower hurdle rate, of $1.50/MWh, but must be executed in peak or off peak strips. The hourly utility-to-utility trades are not restricted to peak/off peak strips, but have a higher hurdle rate of $6/MWh.

- Markets+ Seam Trades: include any trade into or out of the Markets+ footprint. The Markets+ mandates the implementation of intertie bidding, which means that utilities or power marketers can submit import or export bids and the market will automatically clear any that are economic. Markets+ seam trades have a hurdle rate of $3/MWh.
- EDAM/WEIM Seam Trades: include any trade into or out of the EDAM (in the day-ahead timeframe) or the WEIM footprint (in the real-time). The EDAM and WEIM do not require each member to implement intertie trading. As a result, I model them similar to bilateral trades with a $6/MWh hurdle rate. This is likely conservative since trades at the EDAM seam will likely be more efficient than bilateral trades today in the WECC, as they will benefit from transparent market pricing, hourly granularity of trading (compared to block trading at the hubs today in the WECC), and the liquidity of the EDAM.
- RTO Seam Trades: these trades include all imports or exports from the CAISO and SPP West RTO. These trades have a hurdle rate of $1.50/MWh, which captures the relative efficiency of intertie trades into an RTO market compared to bilateral trades.

The hurdle rates I apply to each seam trade are in addition to costs for short-term transmission service, where necessary to execute a trade, and greenhouse gas ("GHG") costs where applicable.

20. Q. PLEASE EXPLAIN HOW NV ENERGY'S TRADING DYNAMICS CHANGE FROM THE BAU CASE TO THE EDAM AND MARKETS+ CASES.

A. NV Energy's trading patterns in the two market cases are driven by the transmission infrastructure and generation resources in the two markets. The flows of power into, out of, and through the NV Energy BAA are illustrated in the figures below, which show the largest changes in total trading volume by NV Energy in each day-ahead market participation case relative to the BAU case.

- **EDAM Case:** In the case where NV Energy joins EDAM, I observe several large shifts in trading relative to the BAU case. First, imports from the California EDAM members (mainly CAISO and LADWP) increase by about 9.5 TWh as NV Energy imports low-cost excess renewable power. Second, the additional imports from California enable wheel-through transactions from NV Energy to other EDAM members (Idaho Power and PacifiCorp) and to the Arizona utilities in Markets+, which drives increased market congestion revenues, short-term wheeling revenues, and bilateral trading revenues for NV Energy in EDAM.
- **Markets+ Case:** In the case where NV Energy joins Markets+, imports from California decline about 3.5 TWh due to NV Energy's departure from the WEIM. The exit from WEIM also reduces NV Energy's trading with PacifiCorp and Idaho Power. Trading with the Markets+ members greatly increases, with both the Arizona utilities and BPA as NV Energy transmission helps enable Markets+ transactions between the Pacific Northwest and Arizona.

FIGURE TSOUKALIS DIRECT-13: LARGEST CHANGES IN TRADING VOLUMES: EDAM CASE VS. BAU CASE

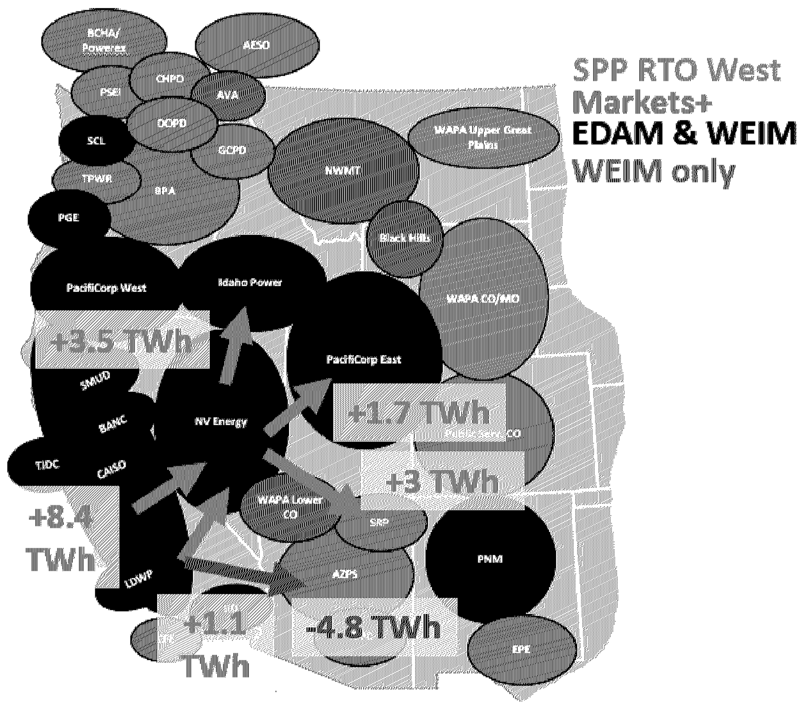
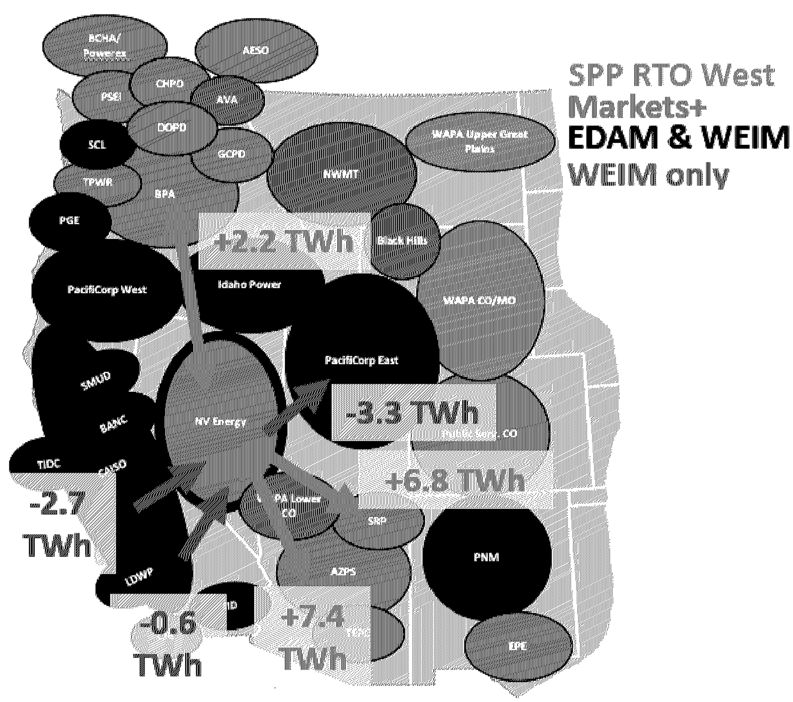


FIGURE TSOUKALIS DIRECT-14: LARGE CHANGES IN TRADING VOLUMES: MARKETS+ CASE VS. BAU CASE



21. Q. HOW SENSITIVE ARE THE BENEFIT RESULTS CALCULATED FOR THE EDAM CASE TO WHEEL-THROUGH TRANSACTIONS TO THE SOUTHWEST?

A. As I note above, in the case where NV Energy joins EDAM, there is a large wheel-through of power from California to NV Energy within EDAM, and then onto the Arizona utilities in Markets+ as a short-term bilateral trade across the market seam. This wheel-through creates benefits for NV Energy customers in the form of increased trading margins and higher short-term wheeling revenues. Given NV Energy's strong connection with both California and Arizona, this result is reasonable and NV Energy's membership in EDAM will likely create opportunity for increased cross-market trades and the associated benefits for customers. However, I analyzed the robustness of NV Energy's market participation benefit in EDAM assuming that these cross-market trades do not materialize. I calculated the benefit of EDAM participation for NV Energy assuming that its short-term bilateral trading with the Arizona utilities in Markets+ remains the same as it is in the BAU case. This is likely overly conservative, as NV Energy's participation in a day-ahead market will likely create opportunities for cross-market trading. **Figure Tsoukalis Direct-15** shows the updated market participation benefit metrics for NV Energy for EDAM (the numbers in the figure have not been adjusted for the Markets+ and BAU cases). Under these assumptions, NV Energy's net benefit of joining EDAM is about $60 million a year.

FIGURE TSOUKALIS DIRECT-15: SUMMARY OF NV ENERGY MARKET PARTICIPATION BENEFITS WITHOUT ARIZONA WHEEL-THROUGH TRANSACTIONS IN THE EDAM CASE ($ MILLIONS)

Metric	BAU	EDAM	Markets+
Adjusted Production Cost	$558.5	$524.3	$566.4
Short-Term Wheeling Revenues	$12.8	$11.7	$0.4
EIM Congestion Revenue	$1.1	$4.8	$0.0
EDAM Congestion Revenue	$0.0	$56.0	$0.0
Markets+ RT Congestion Revenue	$0.0	$0.0	$2.6
Markets+ DA Congestion Revenue	$0.0	$0.0	$25.7
Bilateral Congestion Revenue	$43.7	$10.9	$29.6
Net System Cost	$500.9	$440.9	$508.2
Benefit Relative to BAU Case		$59.9	-$7.3

III. Modeling Tool and Case Assumptions

22. Q. PLEASE EXPLAIN THE APPROACH AND TOOLS USED TO ANALYZE THE CUSTOMER SAVINGS CREATED BY EACH MARKET.

A. I rely on a production cost simulation model, Power System Optimizer ("PSO"), to simulate the operation of the power system in NV Energy's service territory and the WECC. The results of these simulations are used to calculate most of the customer savings metrics I discuss in this testimony, including APC, market congestion revenues collected by NV Energy, and short-term wheeling revenues.

23. Q. PLEASE DESCRIBE THE PRODUCTION COST SIMULATION MODEL USED TO ANALYZE THE BENEFIT OF MARKET PARTICIPATION.

A. PSO, developed by Polaris Systems Optimization, Inc. and run in the Enelytix modeling environment, is a state-of-the-art market and production cost modeling tool. It simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to those used by ISOs/RTOs, and with advanced features for modeling bilateral trading and contract path limits as well as the unique features of energy and ancillary service market designs, such as the EDAM. The model developed for this study was based on the model developed for NV Energy and other joint market benefits study participants between the summer of 2023 and January 2024 to conduct several studies of the benefits and costs due to participating in the EDAM or Markets+ regional power markets, including the study conducted for NV Energy and presented to the Commission on April 3, 2024.[3] The model has had data on load, resource mix, transmission limits, fuel prices, and other assumptions provided by a variety of western utilities across more than a dozen studies.

24. Q. PLEASE EXPLAIN THE ASSUMPTIONS USED TO MODEL THE WECC AND NV ENERGY.

A. The model was developed in collaboration with NV Energy staff to reflect the latest available NV Energy load, resource, and transmission outlooks from the NV Energy Integrated Resource Plan ("IRP") and transmission teams. I worked with NV Energy to update load, resource, and transmission outlooks to align with the best available views as of Fall 2025.

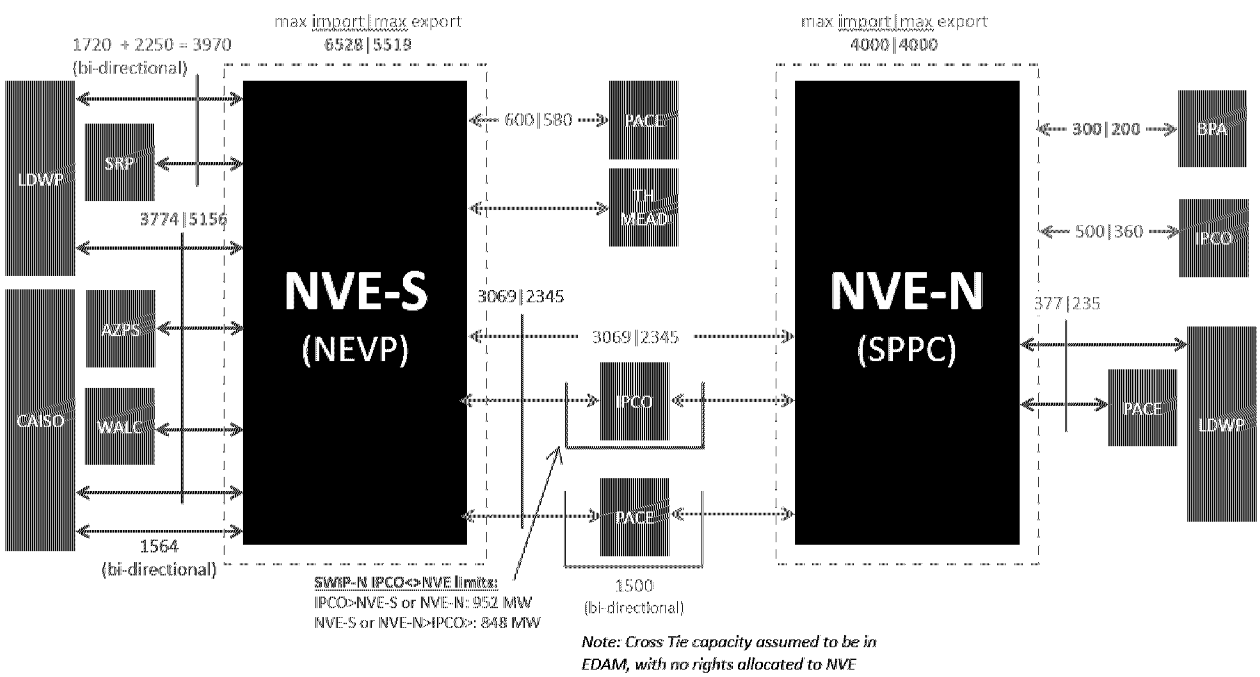
To capture the impacts of market participation on system operations and costs in the model, I worked with the NV Energy transmission team to refine the assumptions used in the model for transfer capability between NV Energy and its

[3] *See* The Brattle Group, NV Energy Day-Ahead Market Benefits Studies: Comparative Benefits for NV Energy of Joining EDAM vs Markets+, April 3, 2024, available at: https://www.brattle.com/insights-events/publications/nv-energy-day-ahead-market-benefits-studies-comparative-benefits-for-nv-energy-of-joining-edam-vs-markets-2/.

neighbors, and between northern NV Energy ("NVE-N") and southern NV Energy ("NVE-S").

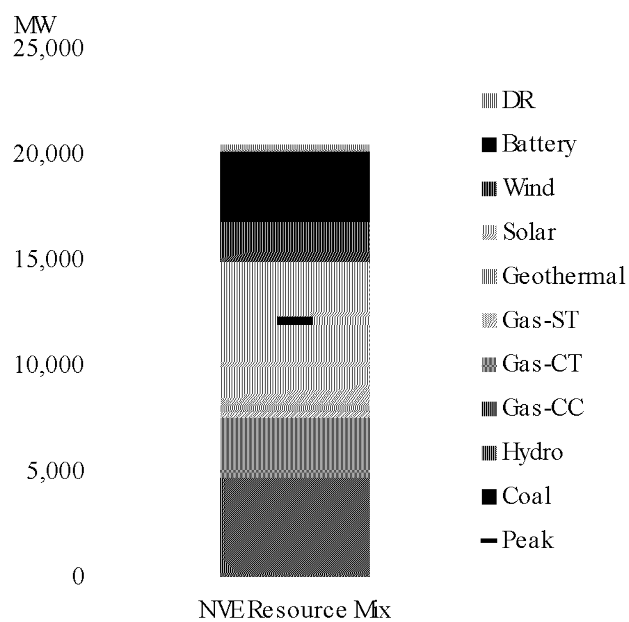
Figure Tsoukalis Direct-16 shows the TTC assumptions between NV Energy and its neighboring systems, as well as between the northern and southern systems. These limits remain consistent through all three modeled cases. On top of these transfer limits, the WECC paths and major transmission interfaces like Greenlink, Southwest Intertie Project ("SWIP") North, and Cross-Tie are also enforced in the study.

FIGURE TSOUKALIS DIRECT-16: NV ENERGY TRANSFER CAPABILITY (MW)



I additionally worked with the NV Energy resource planning team to reflect the expected resource mix and load for the NV Energy's northern and southern systems in 2032, which is reflected in **Figure Tsoukalis Direct-17**. The modeled NV Energy total system load in 2032 is about 51 TWh with a system peak of 12.1 GW. The modeled resource mix for NV Energy in 2032 is about 7.6 GW of gas, 6.8 GW of solar, 1.9 GW of wind, 3.3 GW of battery storage (almost all 4-hour duration), 0.3 GW of geothermal, and 0.5 GW of assorted other resources, mainly hydro and demand response.

FIGURE TSOUKALIS DIRECT-17: NV ENERGY INSTALLED CAPACITY IN 2032 AND SYSTEM PEAK MODELED



For other balancing authorities in the WECC, the data source for their resource mix, load, and transmission limits is either the utility directly, if the utility has been a party to one of these studies previously, or is the utility's most recent IRP. Utilities that have provided system data like NV Energy has for transmission, resources, and load include PacifiCorp, the BANC, LADWP, Idaho Power, PGE, PNM, Turlock Irrigation, EPE, and SCL.

Major changes in modeling assumptions since the prior work for NV Energy included:

- NV Energy's system assumptions were updated by the Companies' transmission and resource planning teams to reflect higher load and resource additions by 2032, the addition of the Greenlink Projects, and changes in gas prices.
- New transmission lines including TransWest Express, SWIP North, Cross-Tie, SunZia, and Southline were added into the model.
- Resource mixes modeled were updated for other entities in the WECC via public resource plans and other data.
- Brattle conducted studies with Public Service New Mexico, Idaho Power, PacifiCorp, El Paso Electric, Turlock Irrigation, and Seattle City and Light since our prior NV Energy studies that lead to significant changes to their systems' modeling assumptions.
- Other updates include, creating a new BAA for Black Hills Power & Cheyenne Light Fuel and Power and adding them to the WEIM, adjusting to dispatch parameters of pacific northwest hydro to make it more price responsive based on information provided by the Northwest Power and Conservation Council, and adjusting transmission limits on SWIP North and Greenlink in consultation with the NVE transmission team.

25. Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT TSOUKALIS-DIRECT-1

John H. Tsoukalis

PRINCIPAL

Washington, DC 1 (202) 527-0219 John.Tsoukalis@brattle.com

Mr. John Tsoukalis is a principal at The Brattle Group specializing in electric power sector economics, modeling, and regulation. His expertise includes nodal production cost and power flow simulations of wholesale markets and regional power systems. He is experienced in assessing the value of transmission rights, analyzing the effectiveness of transmission cost allocation processes, and helping transmission developers to analyze investment opportunities throughout the US and Canada. His experience extends to analyzing and designing alternative transmission rate designs, assessing the effectiveness of transmission planning processes and designing improvements, and conducting benefit-cost analyses of generation and transmission infrastructure.

He has helped clients assess and evaluate the benefits of transmission infrastructure, participation in wholesale power markets, joint regional unit commitment and/or dispatch, and consolidated balancing area operations. He has conducted production cost simulation models to value regional transmission infrastructure and trading rights and assessed the operation of regional transmission systems. He has analyzed the operation and value of generation assets in bilateral and organized regional power markets and assessed potential market manipulation and market power abuse in wholesale power markets.

Mr. Tsoukalis has worked with Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), cooperatives, public power authorities, and investor-owned utilities on a range of issues related to wholesale power markets. He is experienced in helping ISOs/RTOs and utility clients analyze and design market rules to increase the efficiency of existing wholesale market operations, including the design of transmission charges, operating reserve products, and market power mitigation rules and procedures.

He has testified before the US Federal Energy Regulatory Commission (FERC) and the Alberta Utilities Commission (AUC) in matters related to transmission rate design, transmission cost allocation, and transmission rate cases. He has testified in US District Court in a dispute related to emergency wholesale market transactions. He has provided expert opinions to the FERC related to the development and improvement of effective regional transmission planning and cost allocation processes, as well as the efficient design of ancillary services. His work on market design and the simulation of wholesale power markets has been filed with FERC and US state regulatory authorities.

AREAS OF EXPERTISE

- Benefits and costs of wholesale power markets and regional coordination
- Production cost modeling
- Market design in wholesale power markets
- Analysis of GHG policy and implementation in wholesale markets
- Transmission rate design
- Transmission cost-benefit analyses
- Electric utility strategic planning
- Resource planning and asset valuation
- Market manipulation detection and damages analysis
- Analysis of market power mitigation
- Competitive transmission

EDUCATION

- **Universitat Autònoma de Barcelona, Spain**
  M.Sc. in Economic Analysis, 2012
- **Barcelona Graduate School of Economics, Spain**
  M.Sc. in Economics, 2010
- **Washington and Lee University**
  B.A. in Economics with Honors, 2006

PROFESSIONAL EXPERIENCE

Wholesale Power Market Participation

- **Analysis of Benefits to California Customers from Expansion of the Proposed Extended Day-Ahead Market (EDAM).** On behalf of the California Energy Commission (CEC), simulated the benefits and costs for California customer due to the expansion of the EDAM footprint across the WECC. Simulated several potential market footprints in the WECC and calculated the cost savings for California customers, the environmental impacts of market expansion, and the resource adequacy and reliability implications of a larger EDAM footprint for California customers. Simulated market design features of proposed day-ahead markets, including the use of transmission rights in the markets, the market structures used to restrict and price imports into states with GHG pricing regimes, and the accounting and allocation of congestion revenues collected by the markets. Presented results of the analysis to CEC workshop.
- **Analysis of Congestion Risk Exposure due to EDAM Participation.** On behalf of PacifiCorp, filed an affidavit before the Federal Energy Regulatory Commission (FERC) with respect to the company's requested revisions to the Open Access Transmission Tariff (OATT) to enable the implementation of the Extended Day-Ahead Market (EDAM). The affidavit focused on the protests and comments raised by interveners in the docket, specifically related to the congestion risk for market participants under PacifiCorp's proposed changes to their OATT. I analyzed how congestion patterns are likely to change under the EDAM compared to existing congestion in the Western Energy Imbalance Market (WEIM) and analyzed historical congestion to provide an indication of potential congestion risk exposure in the EDAM.
- **Benefit of EDAM Participation.** On behalf of PacifiCorp, provided testimony in front of the Idaho Public Utilities Commission on the operation and customer benefits of PacifiCorp's planned participation in the Extended Day-Ahead Market (EDAM). Testimony focused on the operational efficiencies achieved in regional wholesale power markets like EDAM and the benefits of conducting a market-wide Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED). Testimony also explained the benefits of optimizing a pool of generation and transmission resources across a broad geographic area, as well as the benefits pooling cost information through bidding behavior in the market. The testimony supported PacifiCorp's efforts to amend the risk sharing mechanism related to net power cost recovery in the state. Reviewed net power cost recovery mechanism in all US states and compared them with Idaho.

- **Analysis of the Benefits and Cost of Membership in the Proposed Extended Day-Ahead Market (EDAM) and Markets+.** On behalf of several utilities in the western US, simulated the benefits and costs of participation in two proposed regional day-ahead markets in the WECC. Simulated the existing bilateral markets, including block trading at the major hubs in the region, intertie trades at the existing RTO seams, and existing real-time imbalance markets. Simulated market design features of proposed day-ahead markets, including the use of transmission rights in the markets, the market structures used to restrict and price imports into states with GHG pricing regimes, and the accounting and allocation of congestion revenues collected by the markets. Presented results of the analysis to seven different state commissions in the WECC.
- **Analysis of Benefits and Costs of Market Reforms for Customers in South Carolina.** On behalf of the South Carolina legislature, analyzed the benefits and costs to customers of numerous different market reform options for the state, including wholesale, retail, and system planning reforms. Developed a customized model, with input and data from a group of stakeholders, of the entire Southeastern U.S. including the Carolinas, Southern Company, all the Florida utilities and cooperatives, TVA, PJM, and MISO. Simulated the Southeast Energy Exchange Market (SEEM) and the other bilateral markets that existed through the Southeastern US and compared the operation of those markets to various types of potential wholesale market designs and footprints.
- **Analysis of Extended Day-Ahead Market (EDAM) in the WECC.** On behalf of a group of utilities in the WECC, simulated the proposed Extended Day-Ahead Market (EDAM) and estimated the benefits of the joint unit commitment and dispatch, pooled transmission rights, and reserve sharing and joint provision under the proposed market structure. Represented the proposed GHG-accounting structure in the EDAM market footprint for transactions across states with GHG policies and states without policies. Represented the bilateral markets in the WECC, including utility-specific unit commitment and dispatch decision-market, trading hubs, block trading, trading margin requirements, wheeling fees, and limited transmission rights/transfer capability between utilities. The bilateral market was compared to the regional market case to estimate benefit metrics.
- **Analysis of Market Participation Benefits.** On behalf of a group of cooperatives, municipal utilities, and federal power authorities in the WECC, simulated the benefits of joining the proposed Southwest Power Pool (SPP) West RTO. Modeled the bilateral markets in the region and the joint unit commitment, economic dispatch, optimization of the DC ties between SPP and the WECC, and pooled reserve procurement under the proposed SPP West RTO.

- **Analysis of the Western Energy Imbalance Service and SPP West RTO.** On behalf of the Southwest Power Pool, conducted a production cost simulation of the Eastern Interconnection and WECC to assess the benefits from creating the Western Energy Imbalance Service (WEIS) and from extending the SPP RTO market into portions of the WECC. Analyzed how transmission systems would operate under the new market structure, including the DC interties that connect the Eastern Interconnection and the WECC and the transmission systems in both interconnections. Calculated benefits for market participation for the utilities interested in joining the new market and for the existing utilities in SPP.
- **Analysis of Participation in Regional Energy Imbalance Markets.** On behalf of Black Hills Corp., Colorado Springs Utilities, Platte River Power Authority, and Xcel Energy, analyzed the production cost benefits from participation in the CAISO-administered Western Energy Imbalance Market and the proposed SPP-administered Western Energy Imbalance Service. Conducted several production cost simulations testing multiple scenarios and wrote report summarizing procedure and findings. The report was filed with the Colorado PUC in a proceeding to explore market participation for Colorado utilities.
- **Analysis of Participation in Regional Energy Imbalance Markets.** For an investor-owned utility in the western U.S., estimated the benefits of participating in an energy imbalance market. Simulated membership in two energy imbalance market options and analyzed the relative gains from each option.
- **Analysis of Regional Market Alternatives for the Mountain West Transmission Group.** For the eight members of the Mountain West Transmission Group in Colorado, Wyoming, and neighboring states, analyzed the costs and benefits of alternative regional transmission and market options. The regional transmission and market analysis included detailed market simulations and estimation of member costs and benefits for (a) retaining the current bilateral market construct; (b) forming a regional transmission group with de-pancaked transmission service; and (c) forming or joining a full "Day 2" regional wholesale power market. The results informed the clients' decision to explore regional market alternatives with existing RTOs.
- **Analysis of Participation in a Regional Wholesale Power Market.** For a group of electric cooperatives, public power authorities, and investor-owned utilities in the western U.S., estimated the benefits of participating in a regional wholesale power market. Simulated membership in a proposed regional wholesale power market under different potential future scenarios and estimated the benefits from participation for each member in the group. Results of the simulations, including the estimated benefits of membership in the

market, were relied upon to inform the clients' decision making regarding joining the proposed market.

Transmission Benefit-Cost Analysis, Rate Design, and Investment

- **Benefit-Cost Analysis of Greenlink Projects in Nevada.** On behalf of NV Energy, analyzed the benefits of the Greenlink transmission projects. The analysis included simulation of the EDAM with and without the Greenlink projects to determine the savings to Nevada customers created by the new transmission infrastructure. Calculated the reduced fuel costs, lower operating costs, emissions reductions, higher congestion and transfer revenues in the EDAM and WEIM allocated to NV Energy, and job and economic stimulus impacts of the investment. Assessed the cost increases on the projects relative to cost increase experienced in the industry for similar transmission infrastructure. Provided testimony before the Public Utilities Commission of Nevada in NV Energy's IRP proceeding.
- **Development of a Formula Rate Template for a Transmission Rate Case.** On behalf of a utility in the WECC, created a formula rate template to support their effort to transition from stated transmission rates to a formula rate. Reviewed formula rate templates from other jurisdictions and previous stated rate filing of the utility to develop a formula rate workbook customized to the utility's needs.
- **Testimony in Transmission Rate Recovery Proceeding.** On behalf of New York Transco LLC, provided expert testimony in front of the FERC analyzing the case for transmission incentives for the Propel NY Energy project. Assessed recent FERC Orders granting transmission incentives (Construction Work in Progress in Rate Base, Project Abandonment, and ROE Incentive Adders) and compared the risk profile of the Propel NY Energy projects against projects that were awarded similar incentives. Provided a review of FERC precedent and legislative mandate for transmission incentives and established the benefits of transmission incentives for customers and transmission developers.
- **Transmission Benefit-Cost Analysis in the WECC.** On behalf of a utility in the WECC, analyzed the benefits of proposed transmission infrastructure. Simulated power markets in the western U.S. to determine the customer savings created by the new transmission infrastructure. Calculated the following benefit and cost metrics: reduced fuel costs, lower operating costs, emissions reductions, the increased sale of short-term transmission service, higher congestion revenues allocated from regional wholesale power markets, higher bilateral trading profits for the utility, and job and economic stimulus impacts of the investment. Also evaluated avoided generation interconnection costs, avoided or deferred

reliability investments and upgrades, and resource adequacy benefits. Presented findings to the state commission.

- **Analysis of Net Power Cost Pass Through Mechanism.** On behalf of an electric utility in the WECC, analyzed the net power cost pass-through mechanisms imposed by the state commission and assessed how participation in a regional day-ahead wholesale power market would influence the utility's ability to reduce net power costs for their customers. Analysis included evaluating the impact of security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) on optimizing the operation of the client's generation and transmission assets. Compared the net power cost pass through mechanisms the client is subject to with mechanisms in states with a similar regulatory and market construct.
- **Assessment of a Utility's Power Market Model used for Net Power Cost Forecasting.** On behalf of an electric utility in the WECC, reviewed their internal models of wholesale market markets in the region and helped them assess how accurately their modeling captured the dynamics of the existing bilateral markets in the WECC and proposed regional day-ahead markets. The analysis was used to inform their net power cost filings with their state commission and to assist utility leadership in making decisions on membership in proposed regional wholesale power markets.
- **Analysis of Local Network Service Transmission Rates in ISO-NE.** On behalf of a generation owner in ISO-NE, analyzed the rate they pay for local network service and helped determine the key drivers for recent rate increases. Assisted the client in developing strategies for mitigating their transmission rates in the future.
- **Analysis of Market for Rights on a Proposed Transmission Asset and Support of Application for DOE Funding.** On behalf of a transmission developer in the WECC, supported their winning application for funding under DOE's Transmission Facilitation Program. Prepared an analysis of market benefits for the proposed transmission line, including an assessment of demand for rights on the line and likely off takers. Presented results to the DOE in a written report and responded to DOE questions, as well as in-person at final round interviews with DOE staff. The project was ultimately selected by the DOE based on the likelihood that the project would be developed and that the rights purchased by DOE would be successfully re-sold.
- **Transmission Benefit-Cost Analysis for Proposed Transmissions Assets in the WECC.** On behalf of an investor-owned utility and independent transmission developer in the WECC, analyzed the benefits and costs of a proposed portfolio of transmission projects. Simulated the bilateral power markets in the region and the WEIM and analyzed the cost of renewable

energy resources that could be integrated through the new transmission compared to higher-cost resources that would be developed with the new transmission. Calculated multiple benefit and cost metrics for the proposed transmission assets, including adjusted production cost, emissions reductions, resource adequacy benefits, reduced congestion, and avoided or deferred reliability upgrades.

- **Transmission Benefit-Cost Analysis for Proposed HVDC Transmission Line between SPP and the WECC.** On behalf of a merchant transmission developer, calculated numerous benefit and cost metrics for a proposed 100-mile HVDC line with a capacity of 3,000 MW that would connect the SPP RTO with major trading locations in the WECC. Simulated the SPP RTO market and the proposed day-ahead regional power markets in the WECC to assess the benefits of the proposed project. Calculated numerous benefit metrics for the proposed line, including adjusted production cost, emissions reductions, resource adequacy benefits, reduced congestion, and avoided or deferred reliability upgrades.
- **Transmission Benefit-Cost Analysis for Proposed HVDC Transmission Line between SPP and MISO.** On behalf of a merchant transmission developer and an investor-owned utility, calculated numerous benefit and cost metrics for a proposed 400-mile HVDC line that would connect the SPP and MISO markets. Simulated the SPP and MISO RTO markets to assess the benefits of the proposed project. Calculated benefit metrics for the proposed line, including adjusted production cost, emissions reductions, resource adequacy benefits, reduced congestion, and avoided or deferred reliability upgrades.
- **Testimony in Transmission Rate Design Proceeding.** On behalf of Capital Power, provided expert testimony in front of the Alberta Utilities Commission (AUC) analyzing the impacts of a proposed new transmission tariff design provided by the Alberto Electricity System Operator (AESO). Analyzed the increase in uneconomic bias caused by the proposed tariff design and cost shifting to other customers in the province. Provided written and oral testimony in front of the AUC.
- **Testimony in Support of Transmission Rate Case Filing.** On behalf of Portland General Electric, provided testimony before the FERC in support of their transmission rate case. Testimony supported the transmission cost of service study filed as part of the rate case and provided explanations on key input and components of the cost-of-service study, including the drivers of change in the company's costs service.
- **Testimony in Transmission Cost Allocation Proceeding.** On behalf of GridLiance High Plains LLC, provided testimony before the FERC on the benefits of transmission assets. Conducted a shift factor analysis to determine how the assets are used to support regional power

transfers. Analyzed transmission contingencies to assess if the assets alleviated system overloads under contingency conditions.

- **Testimony in Transmission Cost Allocation Proceeding involving the Seven Factor and Mansfield Tests.** On behalf of GridLiance High Plains LLC, provided testimony before the FERC applying FERC's Seven Factor Test and Mansfield Test to a set of assets the company was seeking to place in the SPP regional transmission tariff. Applied shift factor and electrical distance analysis to determine how the integration of the assets the relevant zone of SPP. Testimony resulted in a favorable initial decision from the FERC Administrative Law Judge.
- **Design of Transmission Access Charges.** For the California ISO, developed an analysis of cost shifts between participating transmission owners due to different Transmission Access Charges (TAC) structures. Results of the analysis were used by the CAISO in stakeholder engagement during an initiative aimed at re-designing the TAC.
- **Strategic Transmission Planning and Rate Analysis.** For an integrated electric utility client, analyzed the qualitative and quantitative benefits of participating in a joint transmission tariff with interconnected transmission owners. Analyzed the impact on transmission rates. Identified and assessed additional regional integration options, including participation in an existing energy imbalance market, membership in an adjacent RTO, and the development of new regional markets with interested neighbors.
- **Transmission Investment Opportunities Assessment.** For several transmission owners and developers, projected the investment need for transmission infrastructure over the next ten years in all U.S. planning regions. Provided analysis of the different drivers of this investment need and studied the implementation of competitive bidding processes for transmission projects as mandated by FERC Order 1000. Helped create forecasts on the amount and type of competitively sourced transmission investment in each planning region across the US.
- **Analysis of the Benefits of Transmission Investment.** For an investor-owned utility, analyzed the reliability and economic impact of over $3.5 billing in capital expenditures to upgrade and harden their existing transmission assets. The reliability benefits analysis estimated a reduction in lost load due to the transmission investments and applied a value of lost load to the reduction. The economic benefits analysis relied on an input-output model analysis to determine the economic activity, job creation, and tax revenues generated by the upgrades to existing transmission facilities. The results of the analyses were used to support internal decision making on capital expenditures and for discussion purposes with policy makers in the states where the utility operates.

- **Analysis of the Benefits of New Transmission Assets.** For an investor-owned utility, analyzed the economic impact of investing in a new transmission line. Analysis relied on an input-output model analysis to determine the economic activity, job creation, and tax revenues generated by the construction of the new transmission facility. The results were used in testimony in front of two state regulatory commissions.
- **Competitive Transmission Opportunity Assessment.** On behalf of a competitive transmission developer, assessed the opportunity for competitive transmission projects. Analyzed transmission investment needs in each region of the US and reviewed the transmission planning processes and competitive project requirements in each region. Conducted a focused analysis of competitive opportunities in several RTO markets.
- **Analysis of Transmission Rate Design.** For a transmission owner in an ISO market, analyzed the performance of the transmission rate design based on criteria established by the market administrator. Developed alternative rate design proposals for use in the public stakeholder process.
- **Long-Term Transmission Planning.** Supported the development of testimony filed on behalf of a regional transmission planning entity in front of a state regulatory commission. Analyzed the forecasts and model utilized by the planning entity to recommend specific transmission projects. Provided guidance to the commission on the reasonableness of the process implemented by the planning entity relative to industry practices.
- **Evaluation of a Transmission Utility.** For a potential investor, contributed in the effort to evaluate a transmission utility. Helped estimate the size of future rate base through a study of proposed transmission projects within the utility's service territory. This led to an assessment of the likelihood each project would get regulatory approval and ultimately be built and contribute to rate base.
- **Retail Electric and Water Rate Design.** For a municipal electric and water utility in the western U.S., reviewed utility's electric retail rate structure and retail water rate structure. Conducted benchmarking study against similarly positioned electric and water utilities in the region. Provided recommended changes to the rate structures for both water and electric power. Analyzed the rate impact on existing water customers from new infrastructure needed to incorporate new customers.

Wholesale Market Design

- **Expert Report in US District Court in Contract Dispute Related to Bilateral Transactions at Southwest Power Pool (SPP) Seam.** On behalf of an electric cooperative, provided expert report in front of a US District Court. Analyzed the cost of providing bilateral energy sales at the SPP market seams compared to the revenues.

- **Wholesale Market Price Formation and Fast-Start Resource Integration.** For an SPP market participant, analyzed inefficiencies in wholesale price formation and the commitment and dispatch of fast-start resources. Worked with client and SPP teams to develop recommendations and present them in an affidavit before the FERC.
- **Ramping Product Design.** On behalf of an SPP market participant, drafted a white paper on efficient and effective methods and best practices for designing an ancillary service product to procure ramping capacity. Collaborated with SPP staff and the SPP market monitor to develop the best design principles for the ramping product and to integrate that product into SPP's existing day-ahead and real-time energy and ancillary services markets.
- **Design of Ontario Market Power Mitigation Regime in Capacity Auction.** For the IESO, developed methodology for calculating the resource-specific offer caps to be used as part of the market power mitigation regime in the Capacity Auction in Ontario. Public report was issued with recommended approach for use in the stakeholder process and to inform public discussion on the offer cap design.
- **Capacity Auction Design.** For an ISO client, analyzed proposed auction design and provided recommendations on improving the design. Tested the auction clearing and price formation mechanisms to ensure optimal outcomes are achieved and efficient prices are produced from the auction. Provided several recommended changes to the clearing mechanism and price formation procedure, which were utilized by the client to improve the auction design.
- **Financial Transmission Rights (FTRs) Market Design.** For an ISO client, reviewed the existing transmission rights market in the region and developed recommendations for amending FTR market design, including an examination of whether the FTR market provided benefits for load in the region.
- **Ontario TR Market Design.** On behalf of the IESO, reviewed experiences in other regional markets and advised IESO staff on the methodology for allocating surplus congestion rents and TR auction revenues. Co-authored a public report with recommendations on updating the method for distributing congestion account surplus to Ontario market participants.
- **Alberta Capacity Market Design.** On behalf of the AESO, collaborated with AESO staff to develop features of the proposed forward capacity market for Alberta.
- **Ontario Capacity Market Design.** On behalf of the IESO, advised IESO staff on the design of the proposed forward capacity market for Ontario.

- **Assessing the Impact of Dynamic Pricing.** For a regional transmission organization, analyzed the impact of different dynamic rate designs on their system. Focused on determining the reduction in peak load and total energy consumption. Estimated the monetary benefits derived from those reductions. Presented results and the models utilized to internal stakeholders.

Analysis of Clean Energy Markets, Decarbonization Policy, and Environmental Regulation

- **Analysis of the Market for Clean Energy in the WECC.** On behalf of a utility in WECC, analyzed the bilateral market for clean energy in the western US with specific focus on the Pacific Northwest region. Assessed the planned clean energy resources in the western US and compared against the projected demand for clean energy based on state policies. Calculated an hourly supply of available clean energy, defined as clean energy production not claimed by any other load-serving entities to comply with their state policies. Determined a premium for clean energy in each hour relative to bilateral market power prices.
- **Analysis of Proposed US Treasury Rules for Hydrogen Tax Credits.** On behalf of Los Angeles Department of Water and Power, analyzed the proposed regulations (Section 45V rules) on the clean hydrogen production tax credit established by the Inflation Reduction Act (IRA). Assessed how the proposed rules align with the operation of power markets and typical resource planning practices in the western US Proposed alternative approaches for the US Treasury to consider that would reduce compliance cost and ensure qualifying hydrogen production would be clean. Developed a white paper that was filed as part of LADWP's comments on the proposed rules.
- **Simulation of Wholesale Market GHG Rules in the WECC.** On behalf of several utilities in the western US, modeled the proposed GHG market rules in EDAM and Markets+. Simulated the two proposed day-ahead markets and analyzed the operation of both GHG structures on price formation, GHG emissions, and transfers into GHG-pricing states under each market.
- **Analysis of Clean Energy Supply and Demand in British Columbia.** On behalf of a natural gas producer in British Columbia, analyzed the likely demand for clean energy resources in the province considering decarbonization policies and projected electric load growth. Assessed the economic and technical potential to develop various types of clean energy resources in the province, including the cost of new clean energy resources. The results of the analysis were used by the client to assess the potential to electrify their natural gas

production operations in the province, including a potential new liquified natural gas export facility.

- **Simulation of Alberta Power Market under Proposed Federal GHG Reduction Policies.** On behalf of a generation owners in Alberta, simulated investment and operational outcomes for the Alberta power pool through 2050 accounting for proposed federal GHG reduction policies. Analyzed the change in resource mix in the province needed to comply with proposed policies, operational outcomes for client-owned generation assets (and other asset-types in the province), pool prices in the province, and the impact of new generation assets on the exercise of market power on pool prices. Supported client in discussions with federal policy makers.
- **Analysis of Market Participation Benefits under GHG Policies.** On behalf of a cooperative in Colorado, simulated participation in the SPP West RTO under the proposed Colorado GHG policy. Simulated the dispatch cost of GHG in Colorado resources, and the cost of importing generation from out-of-state emitting resources in both a bilateral market setting and the RTO setting.
- **Analysis of Proposed EPA GHG Standards.** For a group of utilities in the WECC, analyzed the impact of the proposed rule on their generation assets, reviewed alternative compliance paths with the utility subject matter experts, and assisted in the preparation of the comments to be submitted to EPA.
- **Review of GHG Accounting Mechanisms in the WECC.** For WEST Associates, a group of utilities in the WECC, cataloged the GHG and clean energy accounting methodologies in use across the western US, including RPS, energy supply disclosures, GHG reporting and reduction rules, and voluntary reporting. Presented a white paper on the findings.
- **Environmental Regulation Impact.** For a merchant power producer, assessed the impact of changes in the regulatory environment on the economic viability of coal-fired generation, particularly focused on the Mercury Air Toxics Standards (MATS) rule.

Resource Planning, Generation Asset Valuation, and Market Assessments

- **Analysis of British Columbia Hydro and Power Authority's Resource Plan.** On behalf of a large power customer in British Columbia, analyzed the resource plan for BC Hydro including the estimated cost and demand for new resources available in the province. The analysis considered the decarbonization policies and related electrification load growth. Assessed the potential for developing various types of clean energy resources in the province, including the cost of new clean energy resources.

- **Valuation of Generation Asset in the Bilateral Power Markets in Florida.** On behalf of an independent power producer, developed a market simulation and resource planning model of the Florida power system. Analyzed the value of a new gas-fired generation resource in Florida in the existing bilateral market structure in the state and under various assumptions on future resource costs. Calculated unit-level operation for a new gas-fired resource and determined the net present value of the asset.
- **Analysis of Market Options for Clean Power in the WECC.** On behalf of a renewable developer in the WECC, assessed the market opportunities for their wind farms after existing PPAs expired. Analyzed future market prices at different potential points of sales (e.g., the AESO market, Mid-C, the CAISO market). Provided information on potential operational hurdles and costs for bring their wind power to market under different strategies. Assessed the potential for coupling wind power with local hydro resources to deliver a firm clean energy product, and the market premium for that product relative to an energy-only PPA.
- **Analysis of Operation of Proposed Wind Farm in Colorado.** On behalf of a renewable developer in the WECC, analyzed the patterns of congestion and curtailments in the Colorado-Wyoming region. Simulated operation of a proposed wind farm under the existing bilateral markets and real-time imbalance markets, and under the proposed SPP West RTO market. Determined exposure to congestion and curtailment risk for the proposed wind resources.
- **Analysis of Generation Resource Investment and Retirement Decision in Alberta.** On behalf of a generation owner in Alberta, simulated investment, retirement, and operational outcomes for the Alberta power pool through 2050. The analysis used Brattle's GridSIM capacity expansion modeling software to determine the profitability of various generation resource types, prices in the AESO market, investment decisions in new resources, and retirement decisions for existing resources. The analysis accounted for the proposed federal decarbonization policies. Analyzed the change in resource mix in the province needed to comply with proposed policies, operational outcomes for client-owned generation assets, pool prices in the province, and the impact of new generation assets on the exercise of market power on pool prices.
- **Analysis of Resource Planning Options.** For a municipal utility in the western US, simulated system operations and estimated production costs under several potential future resource portfolios and potential market participation scenarios under consideration by the utility. Results were relied upon by the utility to inform resource planning and market participation decisions.

- **Valuation of Strategic Investments.** For a private equity firm, estimated the long-term value of two generation assets owned by the firm. Simulated energy revenues for the generation assets under multiple future scenarios to consider the impact of energy policy changes, renewable energy penetration, fuel price changes, and participation in regional wholesale powers markets.
- **Development of a Renewable Procurement Strategy.** On behalf of an electric utility in Canada, analyzed various options for procuring and delivering clean energy resources to their customers from neighboring provinces and US states. Assisted the client in weighing economic, development, and political risks related to different procurement strategies and analyzed the likely future supply and demand dynamics for clean energy resources in neighboring regions. Results of the analysis informed the client's clean energy procurement strategy.
- **Assessment of Reliability Under Deep Decarbonization Scenarios.** On behalf of a utility in MISO, analyzed their resource plan developed to comply with state decarbonization policies. Simulated the operation of their system under deep renewable penetration scenarios and assessed their ability to maintain reliable operation of the system. Results were used to support IRP decision making and as evidence in front of their state commission.
- **Valuation of Generation Assets in the WECC.** On behalf of a merchant generation owner in the WECC, analyzed the market opportunity for two gas-fired combine cycle resources in the bilateral power market in the WECC. Developed a forecast of energy and capacity revenues under different decarbonization policy scenarios and different wholesale market structures in the western US. Assessed the potential demand for energy and capacity from the assets based on resource plans of utilities in the region and state decarbonization policies. The results informed the client's power marketing strategy after the expiration of existing PPAs for the assets.

Analysis of Market Manipulation, Compliance, and Wholesale Market Disputes

- **Analysis of Potential Merger in Alberta.** On behalf of a generation owner in Alberta, analyzed the impact on prices from a proposed merger between two major generation owners in the province. Supported client in comments and presentation before the Canadian Competition Bureau.
- **Breach of Contract Dispute related to Wholesale Power Transactions.** On behalf of Associated Electric Cooperative, Inc. (AECI) analyzed the cost of supplying emergency power

into SPP during Winter Storm Uri and compared cost with payments received through SPP settlement. Estimated damages in the form of unrecovered costs for producing the emergency power. Prepared an expert report filed in US Federal District Court.

- **Compliance Investigation in New Zealand.** For Meridian Energy, analyzed claims made by other market participants and by the Electricity Authority (EA) alleging an undesirable trading situation (UTS) due to Meridian's behavior, and submitted comments to the EA.
- **Compliance Plans for Generation Owners.** For a generation owner in Europe, assisted in-house compliance team in the development of compliance procedures and rules tailored to the specific offer strategies and forecasting methodologies relevant to their generation fleet.
- **Wholesale Electricity Market Manipulation.** For a generation and transmission cooperative in the Southwest Power Pool (SPP), developed analyses to detect potential manipulative behavior in the methodology used to offer their units into the wholesale market. These analyses were used to assess the exposure to regulatory liability and present arguments in front of the FERC.
- **Development of Screens to Detect Manipulation in Electricity Markets.** For several generation owners or power trading firms, designed screens to assist with the detection of a wide variety of behavior relevant to electric power market, including the inappropriate withholding of generation to benefit related positions, the uneconomic or fraudulent offer of generation to garner out-of-market payments, and the use of uneconomic physical or virtual price-making trades to impact the value of price-taking positions. Also evaluated specific types of "gaming" behavior and other types of trades (such as circular schedules, "sham" schedules or "wash-like" transactions) that could be viewed as manipulative.
- **Wholesale Electricity Market Manipulation.** For a generation owner in PJM, supported the construction of analyses to detect uneconomic behavior in the methodology used to offer their units into the wholesale market, as well as estimated any potential price suppression and harm caused to other generators. These analyses were used to assess the exposure to regulatory liability and to calculate possible damages.
- **Uneconomic Bidding.** For a merchant power provider, helped draft testimony filed with a regulatory body to provide clarity in its attempt to establish the proper definition of uneconomic bidding in the wholesale electricity market. Specific focus was paid to the bidding behavior of coal-fired power plants in day-ahead markets.
- **Electric Utility Rate Disputes.** As part of an electric utility rate case, aided in the development of testimony analyzing the financial wellbeing of a large industry customer.

The testimony centered on determining the validity of the industrial customer's claimed need for rate relief.

- **Prevention of Manipulation in Capacity Markets.** Assisted in writing testimony filed in a tariff revision proceeding in front of the FERC. Provided guidance for an RTO in crafting tariff provisions to prevent and properly mitigate manipulative bidding behavior in its capacity market.
- **Prevention of Manipulation in Capacity Markets.** Assisted in writing testimony filed in front of the FERC. Provided guidance on developing market rules and procedures to prevent the manipulation of capacity auctions by imported resources.

Electric Power Strategic Planning

- **Development of a 10-Year Strategic Plan.** For a cooperative in ERCOT, worked with C-suite and executive leadership of the organization to develop a 10-year strategic plan. Led strategic planning sessions with the organization's leadership team to help them establish near-term and long-term priorities, goals, and resource needs, that align with the organizational core values and strategic priorities. Assisted in the creation of a 10-year strategic plan with specific timelines, metrics, resource allocations, and near-term implementation goals.
- **Development of a Regulatory Action Plan.** For an investor-owned utility and renewable developer, led a strategic planning initiative to engage policy staff across the organization to establish key policy areas for the organization. Specific policy objectives were created to focus policy advocacy, identify action items for the next 18 months of advocacy, and identify a longer-term strategic plan for engaging commissions, market operators, and policymakers on the organizations key policy areas beyond the 18-month time frame. Developed a strategic action plan document establishing the regulatory action items for the organization.
- **Development of Strategic Action Plan.** For a cooperative in ERCOT, led a strategic planning initiative to engage with the board of directors to establish their vision for the organization, including core values for the organization to pursue as well as specific and actionable strategic priorities for senior management to implement. Created a framework to ensure the strategic priorities remained up to date and relevant for the cooperative and its members and to ensure that the board remained continually engaged on strategic issues. Led a strategic planning workshop for the cooperative's board of directors and utilized the

output of workshops to create a strategic action plan document memorializing the core values, strategic priorities, and engagement framework.

- **Review and Development of Strategic Plan.** For a public power authority in SPP, led a strategic planning initiative to review existing strategic planning documents, guide the organization in creating an updated strategic plan, and create a framework for assessing evolving industry trends going forward. Led a strategic planning workshop for senior management in the organization and used output of workshop to develop strategic initiatives and milestones for the utility.
- **Strategy Planning for Energy Transformation.** For a public power authority in the Southwest Power Pool (SPP), led a strategic planning initiative to address myriad issues confronting the utility in the near future. The initiative covered de-carbonization, evolving customer preferences, human resource issues, reliability, data and IT challenges, and customer costs. Conducted strategic planning sessions with the executive team at the utility, which lead to the development of a strategic plan and de-carbonization proposal.
- **Integration of Emerging Technologies and Services.** For two distribution cooperatives, conducted a long-term strategic planning effort with executives and managers. Presented materials on technology trends, rate structure challenges and solutions, and challenges with regional transmission cost allocations. Facilitated the development of long-term industry scenarios and strategic responses for a comprehensive corporate strategy.

TESTIMONY AND REGULATORY FILINGS

- Before the Public Utility Commission of Oregon, Docket No. UE 451, *Reply Testimony of John Tsoukalis,* on behalf of PacifiCorp, In the Matter of PacifiCorp's 2026 Renewable Adjustment Clause, August 7, 2025.
- Before the Public Utility Commission of Oregon, Docket No. UE 451, *Direct Testimony of John Tsoukalis,* on behalf of PacifiCorp, In the Matter of PacifiCorp's 2026 Renewable Adjustment Clause, April 1, 2025.
- Before the Federal Energy Regulatory Commission, Docket No. ER25-951-000, *Testimony of John Tsoukalis,* on behalf of PacifiCorp, *re:* Revisions to the PacifiCorp Open Access Transmission Tariff to implement the Extended Day-Ahead Market, March 11, 2025.
- Before the Wyoming Public Service Commission, Docket No. 20000-671-ER-24, *Direct Testimony of John Tsoukalis,* on behalf of Rocky Mountain Power, In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates and Revise the Energy Cost Adjustment Mechanism, August 2, 2024.
- Before the Public Utilities Commission of Nevada, Docket No. 24-05041, *Prepared Direct Testimony of John Tsoukalis,* on behalf of NV Energy, 2024 Joint Triennial Integrated Resource Plan (2025-2044), May 31, 2024.
- Before the Idaho Public Utilities Commission, Case No. PAC-E-24-04, *Direct Testimony of John Tsoukalis,* on behalf of Rocky Mountain Power, In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations, May 31, 2024.
- Before the Federal Energy Regulatory Commission, Docket No. ER24-232-000, *Testimony of John Tsoukalis,* on behalf of New York Transco LLC, *re:* New York Transco LLC Proposed Rate Recovery Mechanism for Propel NY Energy Project, October 27, 2023.
- Before the United States District Court for the Western District of Missouri, Associated Electric Cooperative, Inc. vs. Southwest Power Pool, Inc., Case No. 6:22-cv-03030-BCW, *Expert Report of John H. Tsoukalis*, September 2, 2022.
- Before the Alberta Utilities Commission, Proceeding No. 26911, *Written Evidence of Johannes P. Pfeifenberger and John Tsoukalis*, on behalf of Capital Power Corporation, *re:* AESO Bulk and Regional Rate Design and Modernized DOS Rate Design Application, March 28, 2022.

- "Technical Review Committee's Review of Duke Energy's Solar Integration Service Charge (SISC)," coauthored with J. Pfeifenberger and S. Ross, filed with the North Carolina Utilities Commission, Docket No. E-100 Sub 175, November 1, 2021.
- Before the Federal Energy Regulatory Commission, Docket No. ER22-233-000, *Testimony of John Tsoukalis,* on behalf of Portland General Electric, *re:* Portland General Electric Company's Transmission Rate Filing and Limited Revisions to Open Access Transmission Tariff, October 28, 2021.
- "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," coauthored with J. Pfeifenberger, K. Spokas, J. Hagerty, R. Gramlich, M. Goggin, J. Caspary, and J. Schneider, filed with the Federal Energy Regulatory Commission, Docket No. RM21-17-000, *Comments of the American Council on Renewable Energy*, Exhibit 6, October 12, 2021.
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- "Initial Comments on SPP's Draft Ramp Product Report," prepared for Golden Spread Electric Cooperative, Inc. (with J. Pfeifenberger, J. Chang, and K. Spees), August 30, 2018.
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- "Trade Surveillance Should Not Deter Traders," coauthored with Shaun Ledgerwood, December 27, 2017, published by *Risk.net.*
- "Building an Effective Trade Surveillance System: A Framework-Based Approach using Guidance from Two Recent FERC White Papers," coauthored with S. Ledgerwood, March 20, 2017, published by *The Brattle Group.*
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- "FERC's Market Manipulation Rule: Impact on FTRs and the Virtual Market," Energy Bar Association Midwest Chapter Annual Meeting, March 8, 2016.
- "The Critical Role of Transmission in Clean Power Plan Compliance," Kinetic Conference for Competitive Bidding for Transmission Expansion, November 17, 2015.
- "Investment Trends and Fundamentals in U.S. Transmission and Electricity Infrastructure," JP Morgan Investor Conference, July 17, 2015.
- "Market Manipulation Push is Widening the Compliance Gap," coauthored with S. Ledgerwood, January 23 2015, published on *Risk.net*
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- "The Power of Dynamic Pricing," coauthored with Ahmad Faruqui and Ryan Hledik, *The Electricity Journal*, April 2009, pp. 42-56.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JOHN TSOUKALIS, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: October 21, 2025

John Tsoukalis

John Tsoukalis

TECHNICAL APPENDIX 1

NV Energy Day-Ahead Market Benefit Study

2025 UPDATED CASES

PREPARED BY
JOHN TSOUKALIS

PREPARED FOR
NV ENERGY

OCTOBER 2025

Brattle

Executive Summary

Timeline of the Brattle Team's Western Markets Studies

The nodal WECC model we used for this study includes system-specific data from more than 10 utilities in the WECC giving us a detailed view of the western system, including:

- Long-term transmission rights, contracted resources (and transmission encumbrances), generation additions, transmission additions, renewable diversity and forecast errors, and market design detail implementation
- **The utilities we've worked with have helped hone our model by performing full reviews** of our transmission rights, transmission costs, load forecasts, fuel prices, generation mix and costs, and reserves data, including:
  - The Balancing Authority of Northern California, the Sacramento Municipal Utility District, the LA Department of Water and Power, El Paso Electric, Idaho Power, Portland General Electric, PacifiCorp, Public Service Company of New Mexico, NV Energy, and other utilities in the WECC.

1 Pre-2022 Studies

Western Market Studies
- EDAM Feasibility Study
- SPP RTO Expansion Study
- CAISO EIM GHG Structure Study
- Xcel Colorado WEIS/WEIM Study
- WEIS and SPP Integration Study
- Mountain West RTO Study
- CA SB350 Study

2 2022 EDAM Study

2022 EDAM Benefits Study
We produced an updated assessment of EDAM benefits for five study participants, building on the work done for the 2019 EDAM feasibility study:
- PacifiCorp, BANC, Idaho Power, LADWP, SMUD

3 2023-24 EDAM-M+ Studies

Comparative EDAM-M+ Studies
We refined our 2022 EDAM model with input from several new study participants and included a representation of Markets+. The new study participants included:
- Portland General Electric, NV Energy, Public Service New Mexico, El Paso Electric, and others

4 This Study

Updated NVE Study
We built on our work and modeling enhancements from all prior studies and further updated the model with new information from NV Energy and updated the potential market footprints based on likely participation in each market.

Introduction and Study Purpose

This study analyzes the benefits of NV Energy joining the Extended Day-Ahead Market (EDAM), Markets+, or remaining in the Western Energy Imbalance Market (WEIM) in 2032

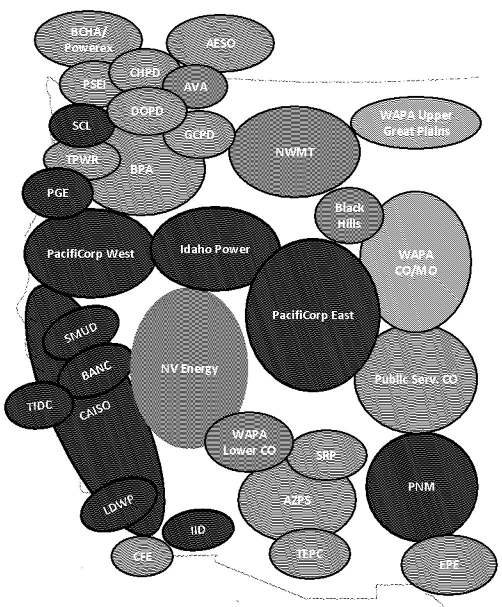
- **Prior Studies with NVE:** Brattle has previously performed similar studies for NVE, including:
  - A calculation of the value of the Greenlink Transmission Projects in May 2024
  - A calculation of the benefit of several market options in January 2024 across a range of 6 scenarios
  - A calculation of the benefit of joining EDAM in fall 2023
- **Major Changes in Modeling Assumptions Since Prior Work**
  - NV Energy's system assumptions have been updated by the company's transmission and resource planning teams to reflect higher load and resource additions by 2032, the addition of the Greenlink Projects, and changes in gas prices
  - New transmission lines like TransWest Express, SWIP North, Cross-Tie, SunZia, and Southline have been added into the model
  - Resource mixes modeled have been updated for other entities in the WECC via public resource plans and other data
  - We have conducted studies with Public Service New Mexico, Idaho Power, PacifiCorp, El Paso Electric, Turlock Irrigation, and Seattle City and Light since our prior NV Energy studies that lead to significant changes to their systems' modeling assumptions
  - Other updates include, creating a new BAA for Black Hills Power & Cheyenne Light Fuel and Power and adding them to the WEIM, adjusting to dispatch parameters of PNW Hydro to make it more price responsive based on information provided by the Northwest Power and Conservation Council, and adjusting transmission limits on SWIP North and Greenlink in consultation with the NVE transmission team

Study NVE Market Scenarios

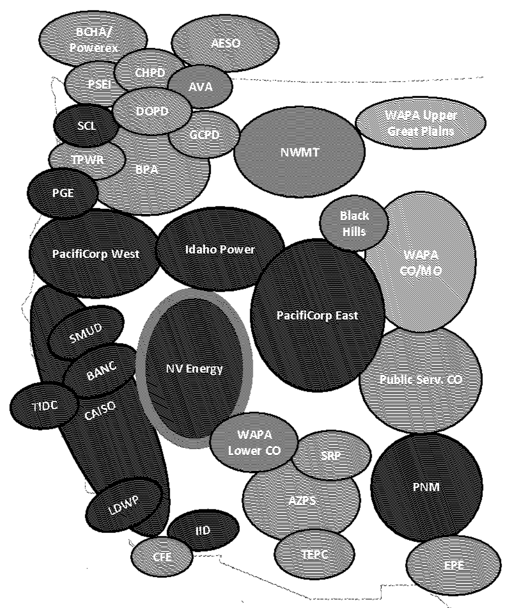
This study includes 3 footprints, a BAU case where NVE stays in WEIM and cases where NVE joins EDAM and case where NVE joins Markets+

- In all cases EDAM and Markets+ already exist with what appears to be the most likely footprint for each market and the only change between all three cases is NVE's market participation

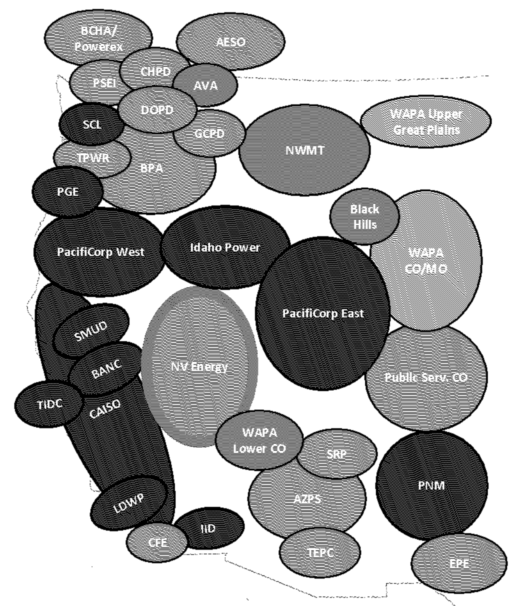
NVE in WEIM



NVE in EDAM



NVE in Markets+



SPP RTO West
Markets+
EDAM & WEIM
WEIM only

Summary of Benefits

We find that NVE customers see cost savings of $93.1 million per year in EDAM, while NVE customers see a cost increase of about $7.3 million per year in Markets+

- **Adjusted Production Cost** is the largest driver of benefits, decreasing by **$34.2 million/year in EDAM** and increasing $8 million/year in M+
  - The cost increase in Markets+ is due to NVE's departure from the WEIM, which allowed NVE to purchase a higher volume of low-cost power from CA
  - In both markets, NVE experiences an increase in market sales revenues. However, in Markets+ purchased power costs increase *(see detailed Adjusted Production Cost results on slides 11 and 12)*
- NVE sells more short-term transmission service in EDAM than in the BAU case or Markets+
  - In EDAM, NVE is a lower-cost wheel-out point for EDAM exports to Arizona from CA, compared to CAISO or LADWP, which increases NVE's short-term wheeling revenue and bilateral trading revenue
  - The large increase in short-term wheeling revenue may imply that NVE will need to pay into the EDAM transmission revenue requirement (TRR) recovery mechanism.
  - The next slide shows the benefits for EDAM participation without trades to the Arizona utilities, which illustrates what benefits for NVE customers would be if the wheel-through transactions from CA to AZ did not materialize.

Summary of NVE Net Cost by Case ($ Millions)

Metric	BAU	EDAM	Markets+
Adjusted Production Cost	$558.5	$524.3	$566.4
Short-Term Wheeling Revenues	$12.8	$40.5	$0.4
WEIM Congestion Revenue	$1.1	$4.8	$0.0
EDAM Congestion Revenue	$0.0	$56.0	$0.0
Markets+ RT Congestion Revenue	$0.0	$0.0	$2.6
Markets+ DA Congestion Revenue	$0.0	$0.0	$25.7
Bilateral Trading Revenue	$43.7	$15.3	$29.6
Net System Cost	**$500.9**	**$407.7**	**$508.2**
Benefit Relative to BAU Case		**$93.1**	**-$7.3**

Sensitivity of EDAM Benefit to Wheel-Through Transactions

If we remove all short-term wheeling revenues and bilateral trading gains associated with trades from NVE to the Arizona utilities, we find that the benefits of EDAM participation are $60 million/year

- This assumes that no bilateral trading will occur between NVE (in EDAM) and Arizona (in Markets+), which is overly conservative.
- These results illustrate a possible low-end estimate of the range of benefits for EDAM participation, in which cross market transactions are more limited than we model.

Summary of NVE Net Cost by Case ($ Millions)
Reducing Southwest Trading Value to BAU Levels

Metric	BAU	EDAM	Markets+
Adjusted Production Cost	$558.5	$524.3	$566.4
Short-Term Wheeling Revenues	$12.8	$11.7	$0.4
WEIM Congestion Revenue	$1.1	$4.8	$0.0
EDAM Congestion Revenue	$0.0	$56.0	$0.0
Markets+ RT Congestion Revenue	$0.0	$0.0	$2.6
Markets+ DA Congestion Revenue	$0.0	$0.0	$25.7
Bilateral Trading Revenue	$43.7	$10.9	$29.6
Net System Cost	**$500.9**	**$440.9**	**$508.2**
Benefit Relative to BAU Case		**$59.9**	**-$7.3**

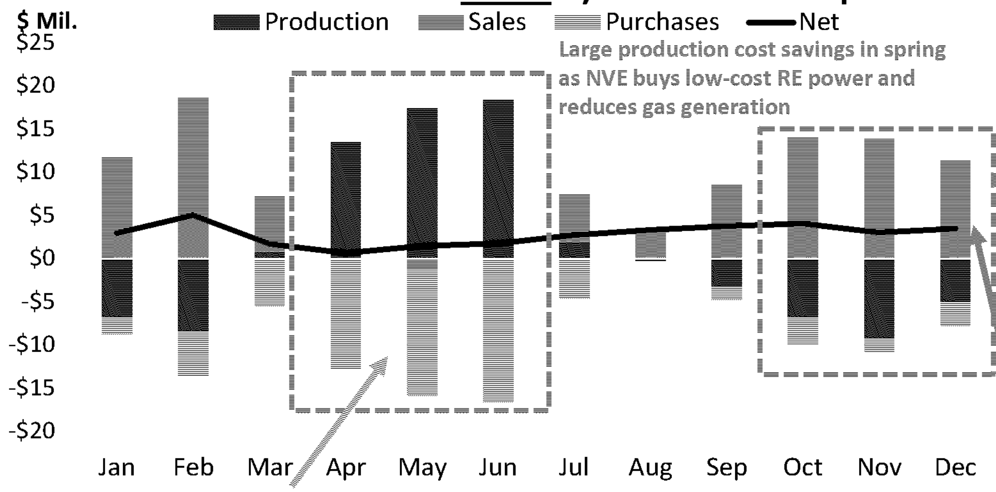
Modeling Results

Adjusted Production Cost Benefit Drivers by Market

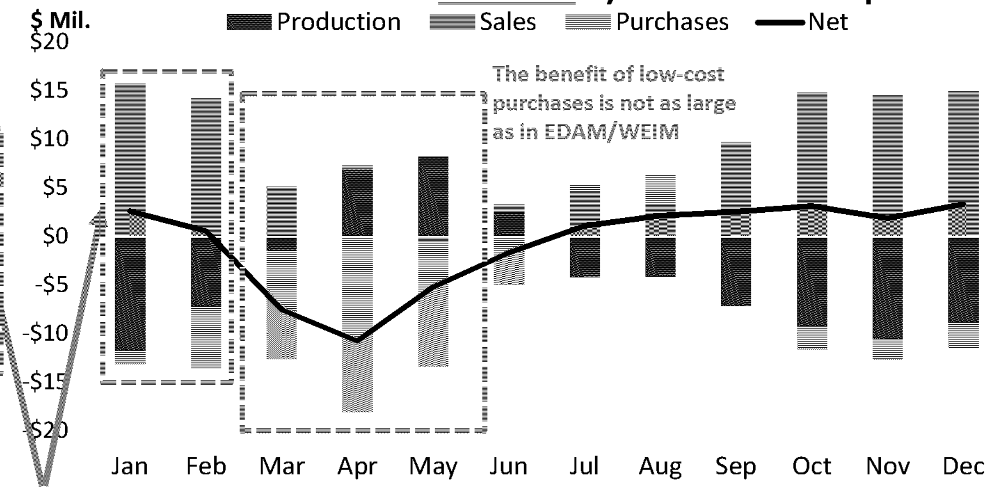
NVE's higher APC benefit in EDAM is mainly coming from the spring when EDAM has excess to low-cost generation, mainly solar from CA

- In the charts below, positive values show benefits to NVE customers. Positive values for production cost or purchase costs represent net declines in system cost, while positive sales revenues represent net increases in system revenue

Net APC Benefit for NVE in EDAM by Month and Component



Net APC Benefit for NVE in Markets+ by Month and Component



Increased purchased power costs offset by production cost savings

In both markets, NVE earns high market sales revenues, partially offset by higher production cost due to generating more power for market sales

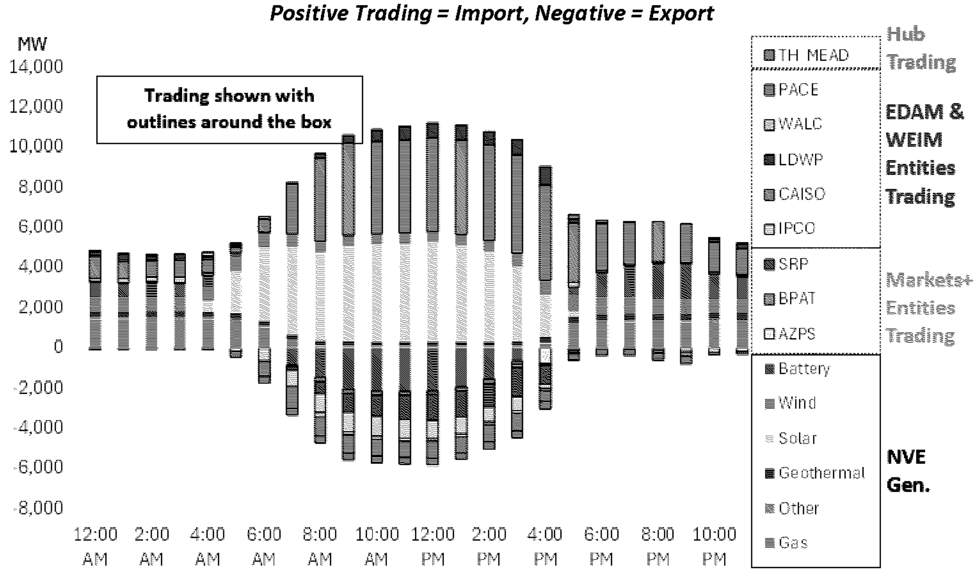
NVE System Behavior in Spring

The hourly dispatch and trading patterns in the spring illustrate the increased APC benefit to NVE from joining EDAM, with large imports from CA entities during solar production hours

- In the Markets+ case, NVE's trading with California declines considerably due to their leaving the WEIM

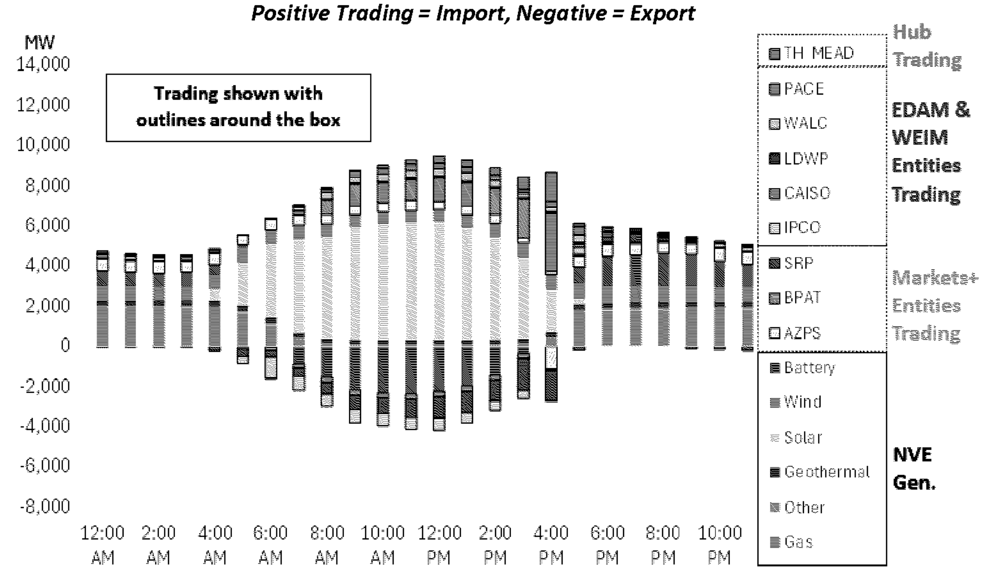
NVE Average Hour of Day Trading and Dispatch in Spring – EDAM Case

Positive Trading = Import, Negative = Export



NVE Average Hour of Day Trading and Dispatch in Spring – Markets+ Case

Positive Trading = Import, Negative = Export



Adjusted Production Cost Benefits: **EDAM**

NVE's APC benefit of $34.2 million is driven by:

- (1) $11.7 million **generation cost decrease** due to a ~700 GWh decline in gas generation
- (2) **$70.2 million purchase power cost increase** from higher purchase volumes offset some by lower average cost of purchasing in the day-ahead
- (3) $92.6 million **sales revenue increase** from shifting ~800 GWh of real-time sales to day-ahead and from making more advantageous sales throughout the year at a higher net sales price of $15/MWh in day-ahead
  - Most of this sales benefit comes from the evening and early morning hours in fall and winter when NVE's cheap gas is valuable in the EDAM

Adjusted Production Cost Comparison for NEVADA

						$/MWh			Total ($1000s/Year)			
Cost Components			BAU	EDAM	Difference	BAU	EDAM	Difference	BAU	EDAM	Difference	
Production Cost	(+)	[1]	50,949	50,379	**-570**	$12.95	$12.87	**-$0.09**	659,963	648,232	**-$11,731**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	3,275	7,571	**4,297**	$24.95	$13.81	**-$11.14**	81,710	104,536	**$22,826**	**(2)**
Real-Time Market		[5]	3,684	1,819	**-1,865**	-$3.94	$18.06	**$21.99**	-14,505	32,856	**$47,361**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	3,677	6,432	**2,755**	$16.89	$32.11	**$15.22**	62,081	206,512	**$144,432**	**(3)**
Real-Time Market		[8]	3,304	2,411	**-893**	$32.27	$22.73	**-$9.54**	106,626	54,803	**-$51,823**	
Total Cost *(Negative Difference = Benefit)*		[9]	**50,928**	**50,928**	**0**	**$10.97**	**$10.30**	**-$0.67**	558,461	524,309	**-$34,152**	
% Change in APC											***-6.1%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.

Adjusted Production Cost Benefits: Markets+

NVE's APC loss of $8 million is driven by:

- (1) $47.6 million **generation cost increase** due to a ~2,000 GWh increase in gas generation
- (2) $57.9 million **purchase power cost increase** from higher purchase volumes offset
- (3) $97.4 million **sales revenue increase** from shifting more than 1,000 GWh of real-time sales to day-ahead and from making more advantageous sales throughout the year at a higher net sales price of $13/MWh in day-ahead
  - **The lost value due to leaving the WEIM is observed here**, as real-time purchase volumes decline 1.7 TWh with the average purchase price increasing $17.1/MWh, and real-time sales decline 1 TWh with the average sale price declining $7.15/MWh.

Adjusted Production Cost Comparison for NEVADA

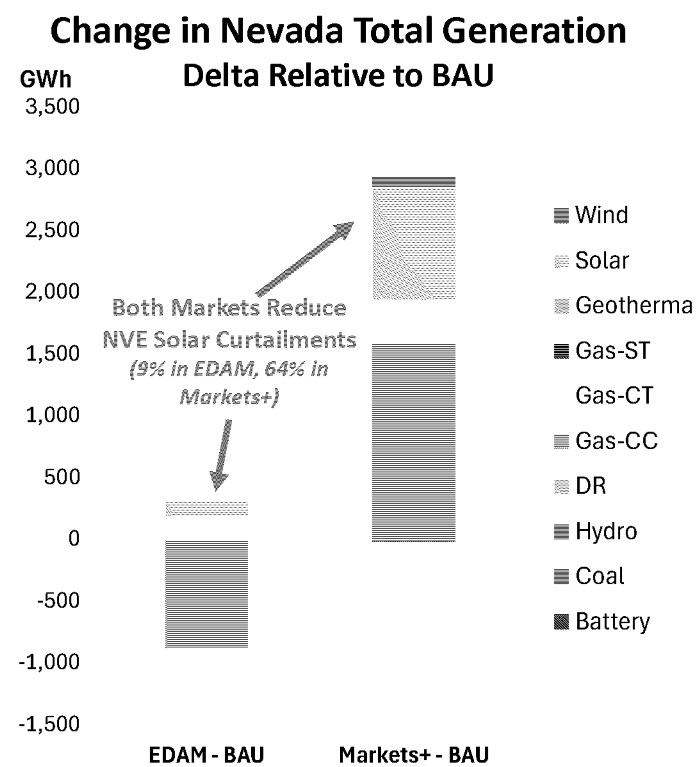
						$/MWh			Total ($1000s/Year)			
Cost Components			**BAU**	**Markets+**	**Difference**	**BAU**	**Markets+**	**Difference**	**BAU**	**Markets+**	**Difference**	
Production Cost	(+)	[1]	50,949	53,858	**2,909**	$12.95	$13.14	**$0.18**	659,963	707,513	**$47,551**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	3,275	4,527	**1,253**	$24.95	$21.98	**-$2.97**	81,710	99,535	**$17,824**	**(2)**
Real-Time Market		[5]	3,684	1,941	**-1,744**	-$3.94	$13.17	**$17.10**	-14,505	25,551	**$40,056**	Value Lost Leaving WEIM
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	3,677	7,140	**3,463**	$16.89	$29.33	**$12.44**	62,081	209,387	**$147,307**	**(3)**
Real-Time Market		[8]	3,304	2,259	**-1,045**	$32.27	$25.13	**-$7.15**	106,626	56,770	**-$49,856**	
Total Cost *(Negative Difference = Benefit)*		[9]	**50,928**	**50,928**	**0**	**$10.97**	**$11.12**	**$0.16**	558,461	566,441	**$7,980**	
% Change in APC											***1.4%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.

Generation and Dispatch Results

NVE's generation is decreasing in EDAM, mostly from gas, and increasing in Markets+, while both markets reduce NVE's solar curtailments

- **In EDAM, NVE reduces gas generation 700 GWh and slightly reduces solar curtailments about 100 GWh**
- **In Markets+ NVE increases gas generation 2,100 GWh and reduces solar curtailments 900 GWh**
- **NVE's solar curtailments fall 9% in EDAM and 64% in Markets+**
- **Generation dynamics are highly seasonal:**
  - Winter and Fall: NVE increases gas generation in both markets
    - Gas generation increases 1,300 GWh in EDAM and 2,200 GWh in Markets+
  - Summer: NVE decreases gas generation in EDAM due to excess renewable supply in the market, but increases it in Markets+, which has less renewable capacity
    - Gas generation falls 800 GWh in EDAM and increases 300 GWh in Markets+
  - Spring: NVE decreases gas generation in EDAM when the market has excess renewables
    - Gas generation falls 1,100 GWh in EDAM and 400 GWh in Markets+
  - Both markets reduce curtailments mostly in the spring, but less in EDAM as California entities add significant excess renewable generation to the market



Market Trading Dynamics

Total NVE trade volume is highest in the EDAM case, as transactions with other EDAM members total more than 33 TWh; in the Markets+ case transactions with other Markets+ entities total ~19 TWh

- **EDAM** offers more variety in trading partners and total transfer capability than Markets+
  - NVE trade more with California entities due to the ability of the market to centrally optimize commitment and dispatch between CA and NV, and access transmission in the market without paying wheeling fees
  - NVE also increasing trading with PacifiCorp and Idaho Power, who have very diverse resource mixes compared to NVE
  - NVE can thus access low-cost, wind, and gas from PAC/Idaho, solar from California
- In **Markets+**, NVE's resource mix is similar to the desert southwest entities in Markets+, which are also solar and gas heavy, offering less diversity in the market footprint
  - NVE's connection to Bonneville Power in the Northwest is small, about 200 – 300 MW, reducing the ability of the market to access Pacific Northwest resource diversity for NV customers

Total NVE Short-Term Trading by Market (GWh)

(Not Including Long-Term Contracts or Trades at the Major Hubs in the WECC)

Trade	BAU Case			EDAM Case			Markets+ Case		
	Imports	Exports	Total	Imports	Exports	Total	Imports	Exports	Total
Nevada Total	10,721	11,016	21,737	20,845	19,245	40,090	13,522	17,513	31,035
Entities in EDAM	9,364	7,790	17,154	19,776	13,432	33,208	5,868	5,381	11,248
Entities in Markets+	600	968	1,568	149	4,090	4,239	6,717	12,122	18,839
Entities in WEIM	757	2,259	3,015	920	1,723	2,643	937	10	947

Note: These numbers do not include any long-term resources contracted inside NVE's balancing authority.

Trading by Counterparty

NVE's total trading is highest in the EDAM case, reaching 41.6 TWh. It is 32.1 TWh in Markets+ and 23.2 TWh in the BAU Case

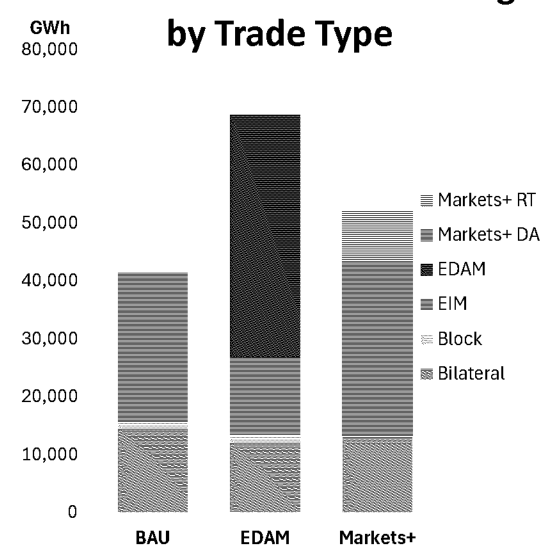
- **Trades in the EDAM case increase mostly with EDAM entities CAISO, IPCO, PacifiCorp**
- **Trades in the Markets+ case increase mostly with Markets+ entities AZPS, BPA, and SRP; and fall with entities in EDAM**
  - Trades with CAISO and LDWP decline because NVE must pay the unspecified GHG cost of ~$27/MWh to excuse short-term bilateral sales into California if they are not in the same market and the ~$15/MWh TAC to buy from California, making most short-term trades in many hours non-economic.

Total NVE Short-Term Trading by Counterparty (GWh)

Trade	Market	BAU Case			EDAM Case			Markets+ Case		
		Imports	Exports	Total	Imports	Exports	Total	Imports	Exports	Total
Nevada Total		11,610	11,631	23,241	21,091	20,543	41,633	14,608	17,539	32,148
CAISO	EDAM	5,614	104	**5,719**	14,053	68	**14,121**	2,887	0	**2,887**
IPCO		1,230	4,130	**5,360**	1,292	7,656	**8,947**	957	5,345	**6,302**
LDWP		918	195	**1,114**	2,068	612	**2,680**	361	0	**361**
PACE		1,601	3,361	**4,962**	2,363	5,097	**7,460**	1,663	36	**1,699**
AZPS	Markets+	0	238	**238**	0	468	**468**	4,621	3,022	**7,643**
BPA		349	493	**842**	105	356	**461**	918	2,087	**3,006**
SRP		251	236	**487**	44	3,265	**3,310**	1,178	7,013	**8,191**
WALC	WEIM	757	2,259	**3,015**	920	1,723	**2,643**	937	10	**947**
TH_MEAD	Hub	889	615	**1,504**	246	1,297	**1,543**	1,087	26	**1,113**

Note: These numbers do not include any long-term resources contracted inside NVE's balancing authority. This table includes trades at the Mead trading hub, which is not included in the table on the previous slide.

Total NVE Short-Term Trading by Trade Type



NVE Trading Dynamics **in the EDAM Case**

In the EDAM, NVE:

- **Imports an additional** 8.4 TWh from CAISO and 1.1 TWh from LDWP
- **Exports an additional** 3.5 TWh to IPCO, 3 TWh to SRP, 1.7 TWh to PACE
  - California to AZPS and SRP exports drop 4.8 TWh at the same time, as it is lower-cost to wheel-through NVE to AZ

Total NVE Short-Term Trading by Counterparty (GWh)

Trade	Market	BAU Case			EDAM Case		
		Imports	Exports	Total	Imports	Exports	Total
Nevada Total		11,610	11,631	23,241	21,091	20,543	41,633
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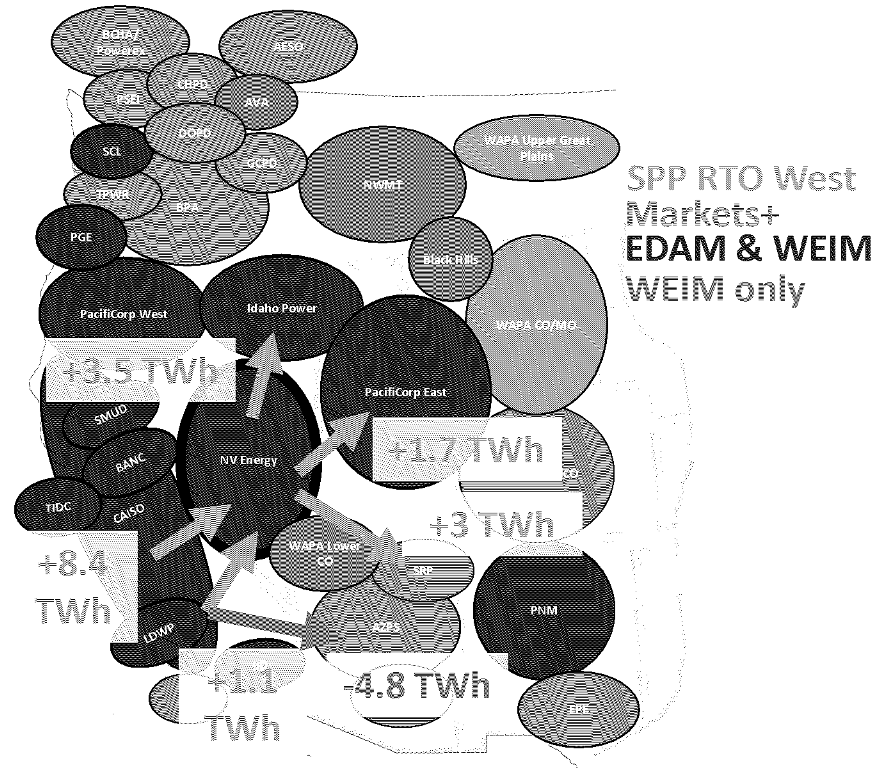
Note: These numbers do not include any long-term resources contracted inside NVE's balancing authority

NVE in EDAM



NVE Trading Dynamics in the Markets+ Case

In Markets+, NVE:

- **NVE imports** 2.7 TWh less from CAISO, 0.6 TWh less from LDWP, and exports 3.3 TWh less to PACE
- **NVE trades an additional** 7.4 TWh with AZPS, 2.2 TWh with BPA, 7.5 TWh with SRP

Total NVE Short-Term Trading by Counterparty (GWh)

Trade	Market	BAU Case			Markets+ Case		
		Imports	Exports	Total	Imports	Exports	Total
Nevada Total		11,610	11,631	23,241	14,608	17,539	32,148
CAISO		5,614	104	**5,719**	2,887	0	**2,887**
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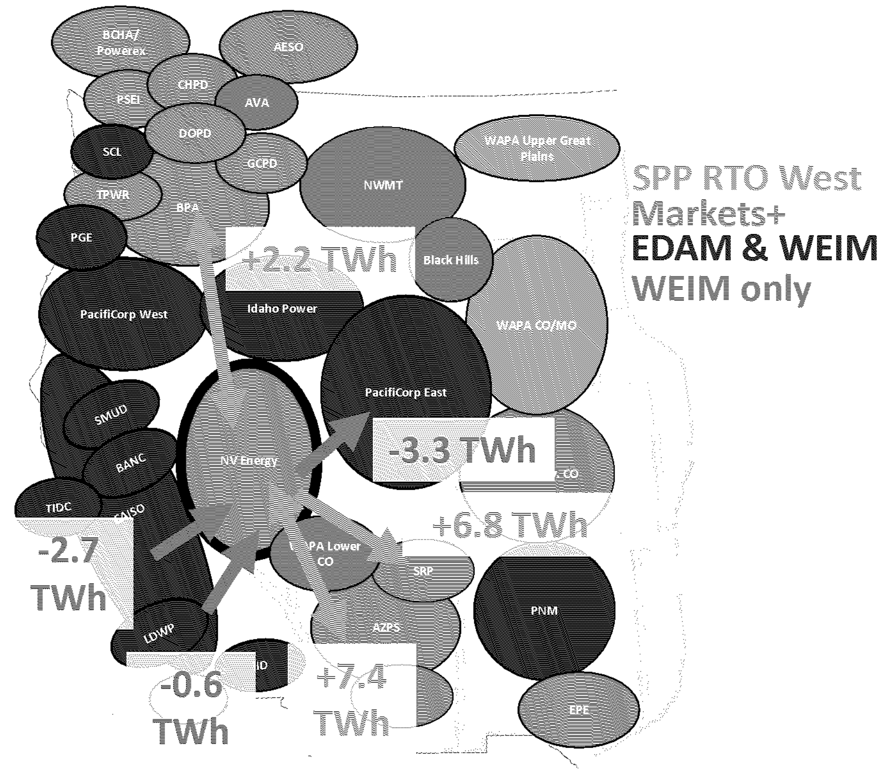
Note: These numbers do not include any long-term resources contracted inside NVE's balancing authority

NVE in Markets+



Appendix:
Explanation of Benefit Metrics

Benefit Metric: Adjusted Production Cost

Adjusted Production Cost (APC) is a standard metric used to capture the direct variable energy-related costs from a customer impact perspective

The APC is calculated for the BAU cases and the market cases to determine the market related reductions in APC

- By using the generation price of the exporter and load price of the importer for sales revenues and purchase costs, the APC metric does not capture wheeling revenues and the remaining portion of the value of the trade to the counterparties (see next slide)

The APC is the sum of production costs and purchased power less off-system sales revenue:

(+) **Production costs** (fuel, startup, variable O&M, emissions costs) for generation owned or contracted by the load-serving entities

(+) **Cost of bilateral and market purchases** valued at the BAA's load-weighted energy price ("Load LMP")

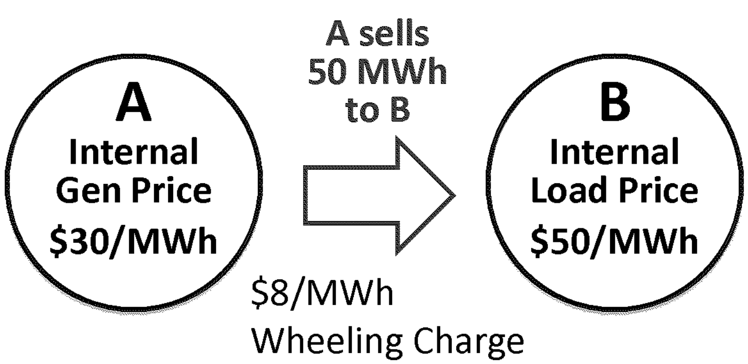
(−) **Revenues from bilateral and market sales** valued at the BAA's generation-weighted energy price ("Gen LMP")

Benefit Metrics: Wheeling Revenues, Trading Gains

Several additional impacts from increased trading facilitated by the market reforms are estimated based on the simulation results, which is not fully captured in APC

- **Wheeling Revenues:** collected by the exporting BAAs based on OATT rates
- **Trading Gains:** buyer and seller split 50/50 the trading margin (and congestion revenues in EIM/EDAM)

EXAMPLE: Bilateral Trade



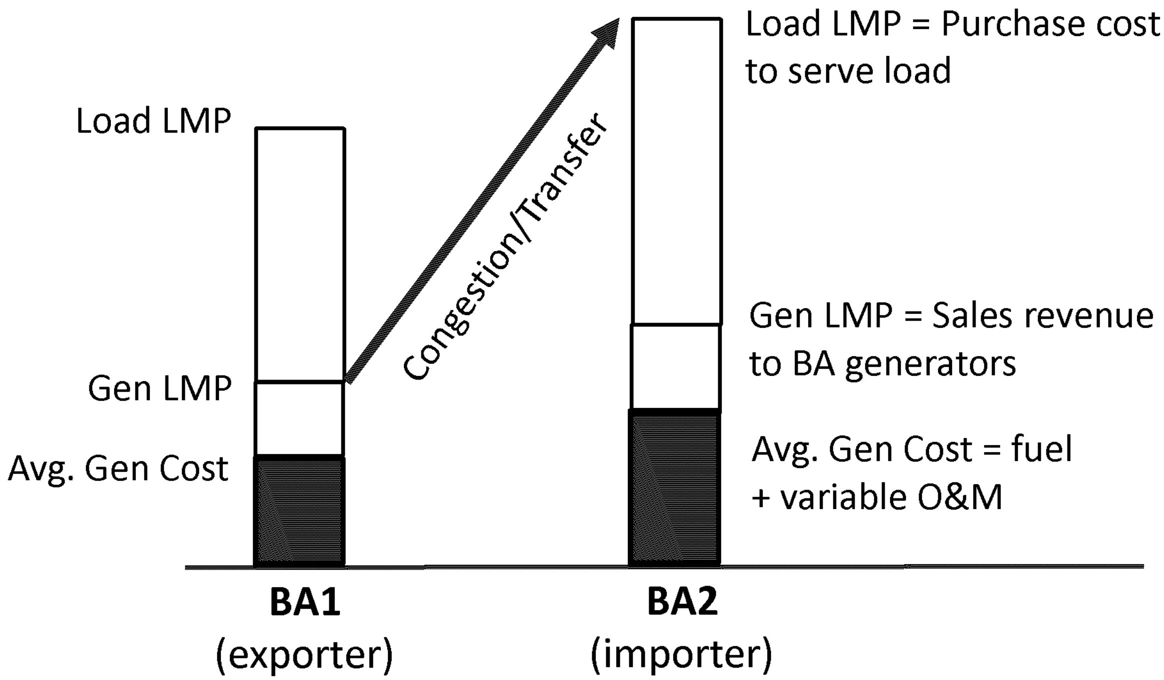
The <u>APC metric</u> only uses area-internal prices for purchase cost and sales revenues, which does not capture part of the value:

- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs
- → $1,000 of trading value not captured in APC metric

Trading value = $20/MWh Δprice x 50 MWh = $1000

- Exporter A receives wheeling revenues: $8/MWh x 50MWh = $400
- Remaining $600 trading gain split 50/50: both A and B receive $300

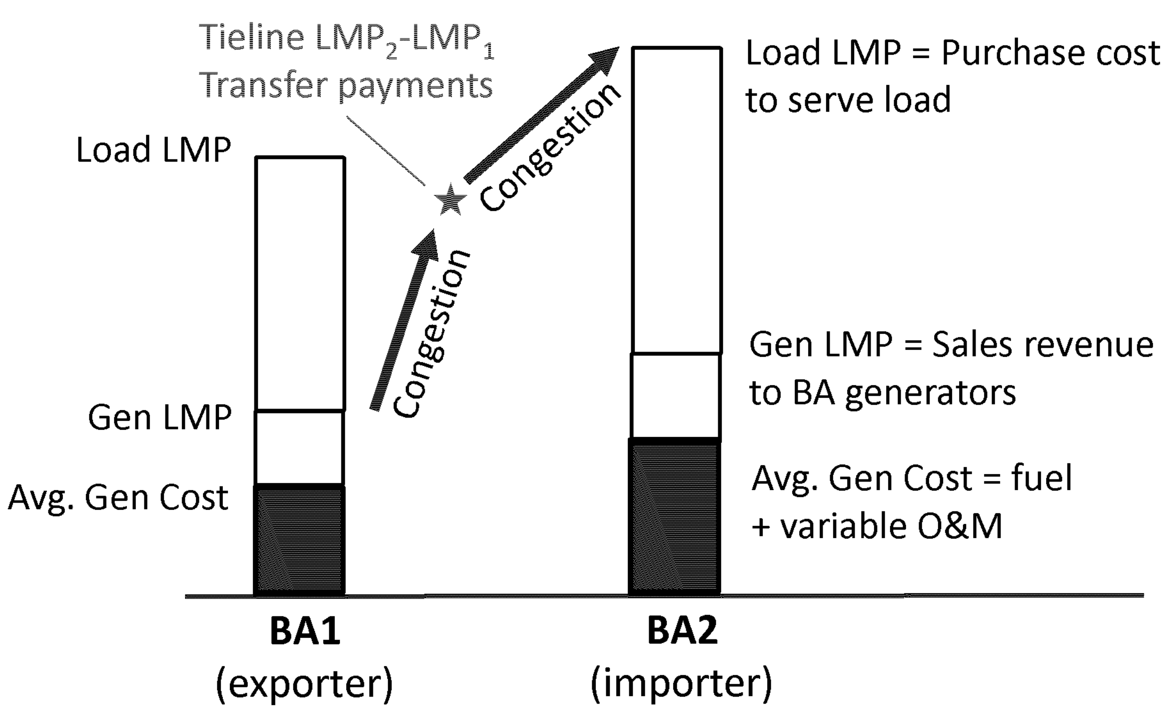
Illustration of Markets+ Congestion Revenues



Markets+ congestion revenues are estimated based on BA load and gen LMPs:

- The BAA is assumed to own all rights on congested paths within their BAA, unless information is available on third-party contracts.
- Similarly, unless information on third-party contracts is available, congestion between market members is assumed to be split 50/50 by the two BAAs
- Congestion/Transfer Revenue Payment (split 50/50) = MW x (Load LMP_2 – Gen LMP_1)

Illustration of EDAM Congestion and Transfer Revenues



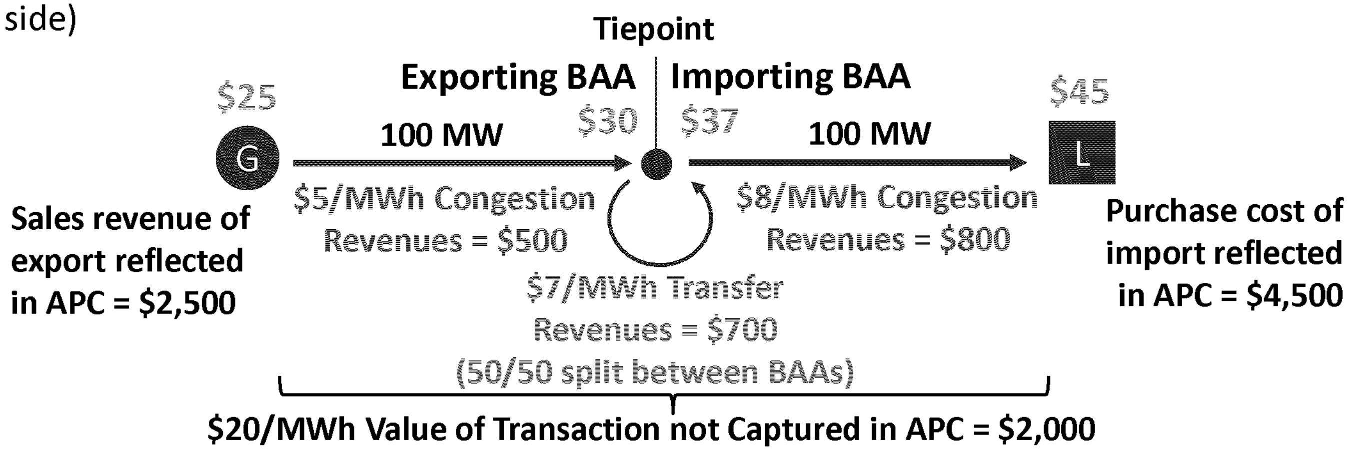
EDAM congestion and transfer revenues estimated based on individual tieline LMPs:

- **Congestion Payment** (to exporter)
  = MW x (Tie LMP_1 – Gen LMP_1)
- **Congestion Payment** (to importer)
  = MW x (Load LMP_2 – Tie LMP_2)
- **Transfer Payment** (split 50/50)
  = MW x (Tie LMP_2 – Tie LMP_1)

Illustration of EDAM Congestion/Transfer Revenues vs. APC

Generators and loads get paid/pay the prices within their BAAs

- Therefore, congestion on internal transfers (between a member's own gen and load) is captured in the APC metric.
- However, congestion/transfer revenue on external transactions (to neighboring members) is not captured in APC.
- In the example below, for an external market transaction, the selling BAA has a price of $25 and the purchasing BAA has a price of $45.
  - The $20 difference between the seller and buyer is the congestion and transfer revenue.
  - $5/MWh of congestion revenue is allocated to the seller ($30 on their side of the intertie less $25 internal gen price)
  - $8/MWh of congestion revenue is allocated to the buyer ($45 internal load price less $37 on their side of the intertie)
  - $7/MWh of transfer revenue is split 50/50 between the buyer and seller ($37 on the buyer side of the intertie less $30 on the seller side)

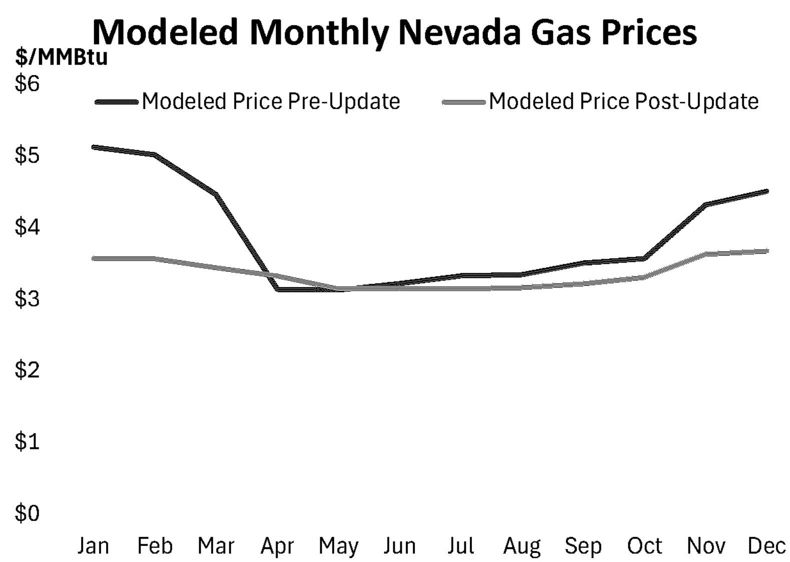


Appendix:
EDAM and Markets+ Modeling Assumptions

Modeled Gas Prices

As part of the updated 2025 study, NVE had us model updated gas prices in-line with their more recent IRP modeling assumptions, reducing gas prices about 13% model-wide

- NVE's average price fell from $3.89/MMBtu in the model to $3.37, about a 13% decline
- For an average NVE Gas-CC this drops the *fuel cost* about $4.2/MWh from ~$31/MWh to ~$27/MWh
- Natural gas prices in the other regions of the WECC were updated to maintain the same basis differential to Nevada gas prices

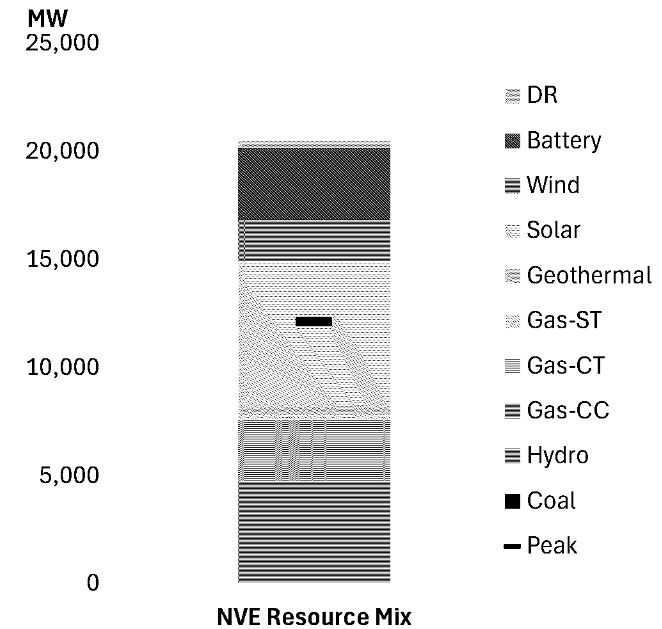


NVE Resource Mix and Load

As part of the 2024 Greenlink Transmission Valuation study, NVE updated its resource mix and load in our model and made additional tweaks to its resource mix for this study that align closely with the most recent NVE IRP

- NVE's modeled load for 2032 is 51 TWh with a system peak of 12.1 GW
- NVE's modeled capacity includes about 7.6 GW of gas, 6.8 GW of solar, 1.9 GW of wind, 3.3 GW of battery, 0.3 GW of geothermal, and 0.5 GW of other resources

NVE Modeled Resource Mix and System Peak



Physical Constraints in NVE BA

Below are the physical constraints and associated limits modeled in and around the NVE balancing authority area

Modeled Physical Limits Around and in NVE's BA

Constraint	Limit	Limit
Greenlink West	2,250 MW East to West	2,250 MW West to East
Greenlink North	2,250 MW North to South	2,250 MW South to North
ON Line	2,598 MW North to South	2,598 MW South to North
Clover-Robison-CrossTie_Constraint	1,500 MW East to West	1,500 MW West to East
P16 Idaho-Sierra	500 MW North to South	360 MW South to North
P24 PG&E-Sierra	150 MW East to West	160 MW West to East
P27 Intermountain Power Project DC Line	2,400 MW Northeast to Southwest	1,400 MW Southwest to Northeast
P32 Pavant-Gonder InterMtn-Gonder 230 kV	500 MW East to West	235 MW West to East
P35 TOT 2C	600 MW North to South	580 MW South to North
P46 West of Colorado River (WOR)	11,200 MW East to West	11,200 West to East
P49 East of Colorado River (EOR)	10,100 East to West	10,100 West to East
P52 Silver Peak-Control 55 kV	17 MW East to West	17 MW West to East
P58 Eldorado-Mead 230 kV Lines	1,140 MW East to West	1,140 MW West to East
P62 Eldorado-McCullough 500 kV Line	2,598 MW North to South	2,598 MW South to North
P77 Crystal-Allen	950 MW East to West	950 MW West to East
SWIP_North_Constraint	2,070 MW North to South	1,920 MW South to North

Hurdle Rate Assumptions

Markets+ and EDAM are modeled with different hurdle rates for seams transactions, as Markets+ automatically enables intertie bidding

- Bilateral transactions pay a $6/MWh friction charge for trades between two non-market entities
  - Bilateral transactions at the Markets+ seam pay $3/MWh, $1.5/MWh at an RTO seam, and $6/MWh at the EDAM seam (plus GHG and transmission service fees, if applicable).
- Exports ***across a market seam*** into a GHG zone are charged an unspecified resource GHG cost (equivalent to the emissions charge for a generic gas-CC unit, about $27/MWh)

Modeled Trading Friction Charges ($/MWh)

Transaction Type	Friction Charge	Transaction Pays OATT?
	$/MWh	*Yes/No*
Bilateral Transactions	$6	Yes*
Block Transactions	$1.5	Yes*
EDAM and WEIM Transactions	*None*	No
Markets+ DA / RT Transactions	*None*	No
RTO Intertie Transactions	$1.5	Yes*
Markets+ Seam Transactions	$3	Yes*
EDAM Seam Transactions	$6**	Yes*

Note: *Trades across long-term transmission rights pay a friction charge, but no hourly OATT rate.
**EDAM seams with Markets+ pay the $3/MWh Markets+ friction.

EDAM GHG Structure: “Reference Cycle”

The GHG modeling structure accounts for two constraints specified in the EDAM design for GHG attributions relative to a baseline from EDAM’s “reference pass” cycle, which is simulated as well

1. **Resource Specific GHG Attribution (resource-type attribution under proposed approach) =**

   max{0, min{GHG Bid, UEL – Reference Pass, Optimal Dispatch}}

   - **Simulations assume resources bid all their capacity into the GHG Region**
   - Calculated using results of the GHG Reference Pass run
   - GHG attribution cannot exceed final dispatch of resource

2. **BAA Total GHG Attribution <= min{BAA Total Export Limit - BAA Hourly Net Exports in reference pass, BAA Total Export Limit}**

These reference pass results set **hourly export limits** that are enforced in the actual EDAM case for EIM and EDAM members for sales to GHG balancing authorities

Markets+ GHG Pricing Structure

It is assumed the Market+ GHG pricing structure will use the following approach:

- GHG surplus identification happens through the Merit Order approach.
  - The Merit Order approach is assumed to apply to all resources in the market, and BAA hourly surplus capacity available for transfer to GHG pricing states is calculated outside of the model using the load data and a merit order constructed from modeled operating cost and capacity assumptions.
  - Resource type-specific GHG costs are applied to surplus transfers to the GHG zone.
- The market optimization is assumed to use the "Enhanced Floating Surplus" approach
  - This allows transfer of type-specific surpluses from anywhere in the dispatch range of eligible resources

Load Following Reserves

Load following requirements are calculated for each market based on net load variability, which results in Markets+ having a lower requirement than EDAM for NVE

In both markets load following reserves (known as Imbalance Reserves in EDAM) are calculated in both the up and down directions to meet the 97.5 percentile of each BAA's historical net load variability.

- In the two market cases, participants' requirements are reduced by the diversity benefit created by pooling commitment and dispatch across the regional footprint.
- Does not impact other operating reserve types – regulation and contingency – which are held by each BAA as in the BAU case.
- The load following reserve requirement is higher in EDAM due to having more renewable resources than in the market footprint than Markets+.

Resource Sufficiency & Transmission

EDAM Resource Sufficiency Test

- EDAM will apply the Resource Sufficiency Test to each member before day-ahead market operations
  - In the 2019 EDAM Feasibility Study, E3 conducted an hourly analysis of Resource Sufficiency for each proposed EDAM member and found that failure was extremely rare.
  - For this study, conducted ex-post check and confirmed that EDAM members are resource sufficient in all hours.

EDAM Transmission

- All three buckets of EDAM transmission are modeled and assumed to be hurdle-free:
  - Bucket 1: Transmission to Support Resource Sufficiency, including existing long-term transmission contracts (ETCs)
  - Bucket 2: "Donated" Transmission Contracts, which are ETCs made available ("donated") to the EDAM by participants
  - Bucket 3: Unsold Firm Transmission (no study participant informed us that they plan to hold back any transmission)
- Simulated Bucket 1 and 2 EDAM transmission equals total ETC capacity; Bucket 3 transmission equals the remaining transfer capability (i.e., TTC less ETC) between the assumed EDAM members

Markets+ Transmission

- All transmission with other Markets+ members is modeled as available in the market without wheeling charges
- There is no transmission assumed to be carved out for WRAP or other resource adequacy purchases.

Appendix: Overview of Power System Optimizer (PSO)

Key Model Features

All study simulations are conducted using a **nodal production cost model of the WECC** with added markets, transmission rights, and contract-path trading functionality

- Model developed in PSO/Enelytix, which contains state-of-the-art features
  - Simultaneously optimizes contract path and physical constraints
  - Models bilateral, day-ahead, and real-time markets (including uncertainty) sequentially through multiple solution cycles
  - Co-optimizes storage resources with other resources in unit-commitment and dispatch
  - Detailed ancillary service and operating reserve modeling (including reserve sharing) and co-optimization of ancillary services with energy
- **The study year is 2032**, which aims to reflect the first decade of markets operations, representing an intermediate year that captures known changes in resource mix and transmission infrastructure
- **Model includes two extreme weather events** based on a historic cold snap and a historic heat wave
  - These events are modeled as single weeks in which modeled loads (peak and energy) and gas prices are increased, including gas price volatility beyond typical weather-normalized values to reflect the increased strain on the system and the ability of markets for addressing such strain
  - Capturing non-weather-normal impacts is becoming increasingly important due to the increasing frequency of severe weather events
- **Detailed modeling of EDAM and Markets+ specific GHG rules** which helps capture transfers into GHG pricing states
  - This includes the limits each market will place on sales to balancing authorities that price GHG emissions and the unit-type GHG cost representations instead of generic GHG charges
  - BPA's status as an asset-controlling supplier for CA and WA is modeled and reflecting their lower cost to sell power into those zones

Multi-Functional Simulation of WECC

Markets/RTO Functions & Configurations

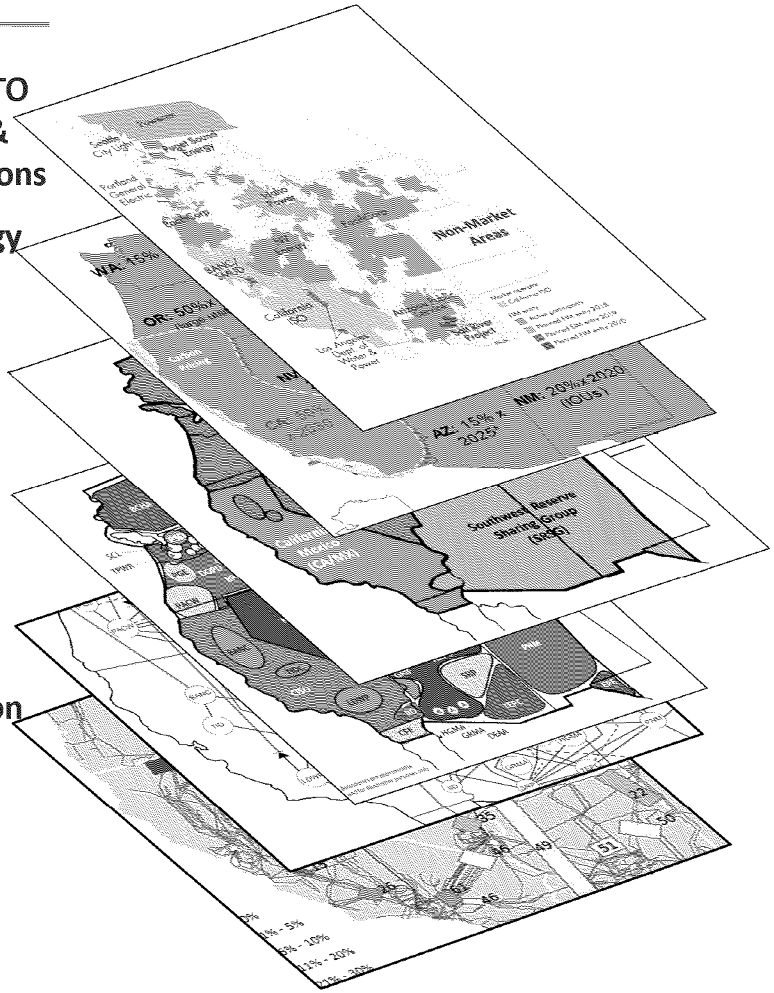
Clean Energy Policies

Reserve Sharing

BAA Functions

Bilateral Contract Paths and Transmission Rights

Physical Flows and Constraints



The model employs multi-layer simulations to represent the various physical, policy, and operational facets of the WECC

- Physical grid with ~20k buses, ~25k lines and ~5k generators represented as DC power flow
- 38 Balancing Authority Areas (BAAs) and contract paths
- WECC reserve sharing groups
- Diverse state clean energy policies
- Major trading hubs (e.g., Mid-C, Malin, PV, FC)
- Bilateral (long-term) transmission rights
- Renewable diversity, day-ahead forecast uncertainty, real-time operations
- CAISO, SPP RTO West, Markets+, EDAM, WEIM, & WEIS footprints

Key Modeling Assumption Sources

Modeling assumptions based on public sources and refined with input from study participants

Assumption Category	Nevada	Rest of WECC
Resource Mix	• Nevada resource mix provided by the NVE IRP team and closely reflects the most recent NVE IRP	• Utility-provided data for El Paso Electric, Idaho Power, Portland General Electric, PacifiCorp, Public Service Company of New Mexico, LADWP, Seattle City Light, BANC, and SMUD • Recent IRP updates for Arizona Public Service, Tucson Electric Power, Avista, Puget Sound Energy, and others
Load	• Nevada load forecast and hourly shapes and forecast errors provided by the NVE IRP team and closely reflects the most recent NVE IRP	
GHG Prices	• GHG prices are based on the CEC's 2022 mid case, with the modeled CA & WA price in 2032 at ~$64/metric ton • The WA and CA carbon markets are assumed to be linked by 2032	
Natural Gas Prices	• Gas prices were provided by the NVE IRP team and follow the assumptions in the most recent NVE IRP	
Transmission	• Participant updates for specific projects, and addition of interregional projects anticipated to be online by 2032, including SunZia, SWIP-N, TransWest Express, Cross-Tie, Greenlink North & West, B2H, Gateway Projects • Enforced physical limits include WECC-rated paths and specific constraints identified by participants • Contract path limits based on public data and participant input and enforced for all BA-to-BA connections	

Overview of Modeling Approach

The WECC ADS nodal production cost model is the starting point imported into Power System Optimizer (PSO), and refined during the EDAM feasibility study and follow-on engagements

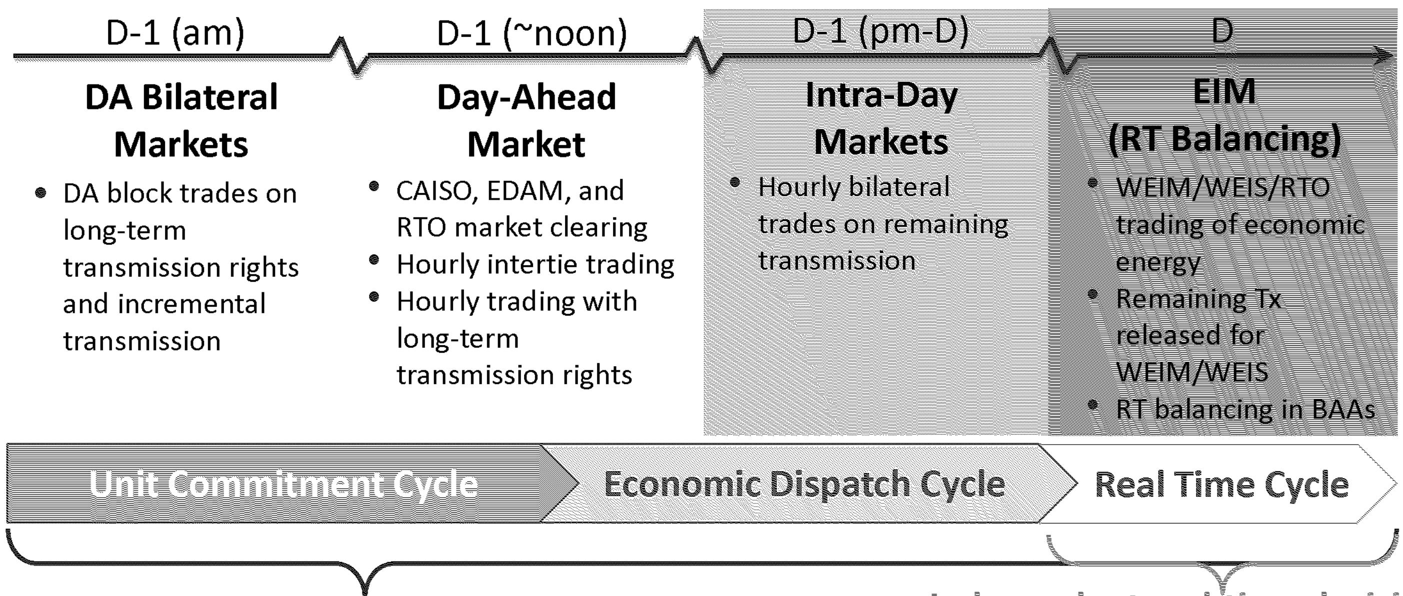
Utilized the Polaris Power System Optimizer (PSO), an advanced market simulation model

- Nodal mixed-integer model representing each load and generator bus in the WECC
- Licensed through Enelytix
- Detailed operating reserve and ancillary service product definition
- Detailed representation of the transmission system (both physical power flows and contract paths)
- Sub-hourly granularity (but used hourly simulations due to limited data availability)
- Designed for multiple commitment and dispatch cycles (e.g., DA and RT) with different levels of foresight
- EDAM feasibility study assumptions updated to reflect the most recent utility resource plans and forecasts of system conditions and costs

PSO is uniquely suited to simulate bilateral trading, joint dispatch, imbalance markets, and RTOs, reflecting multiple stages of system operator decision making

Independent Simulation of Multiple Time Horizons

PSO simulates multiple independent decision cycles to capture day-ahead vs. real-time unit commitment and dispatch



Independent real-time decision cycle used to simulation EIM functions

Decision cycles capture bilateral trading, market clearing, BAA functions in DA and RT, and market cycles (EDAM "GHG reference" pass, EDAM market, and EIM)

Independent real-time decision cycle used to simulate DA vs. RT, including forecast errors for wind and solar

Simulating Several Wholesale Market Cycles in PSO

The model setup for wholesale market simulation effort contains several cycles to simulate unit commitment and dispatch decisions in three different timeframes and within different market structures. For example, cycles simulated can include are:

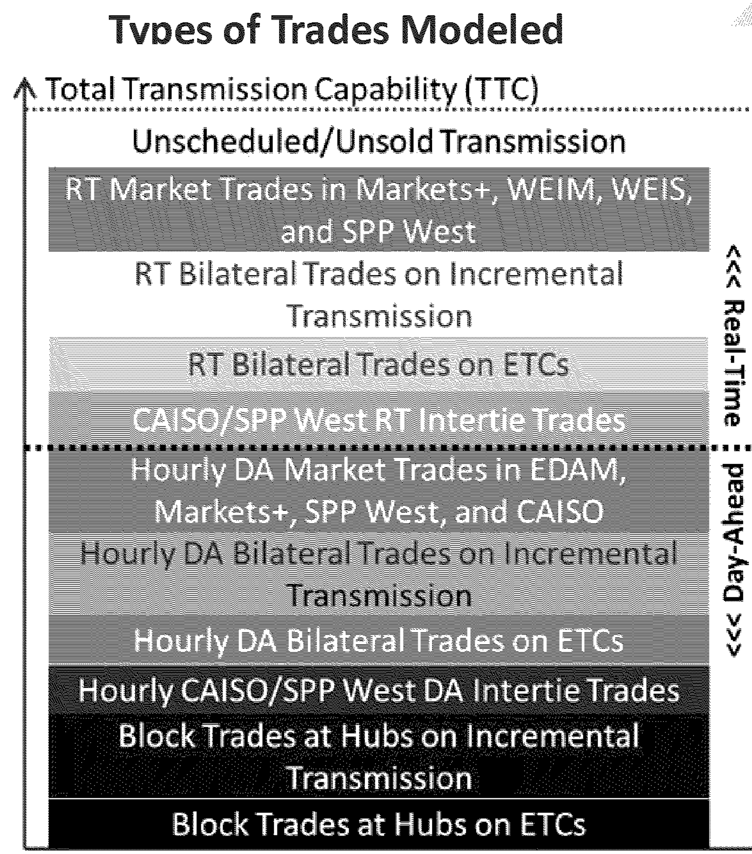
- **Day-Ahead Unit Commitment Cycle:** the model optimizes unit commitment decisions, 24 hours at a time (with 48-hour look ahead), for long-lead time resources such as coal and nuclear plants, based on their relative economics and operating characteristics (e.g., minimum run time, maintenance schedules, etc.), transmission constraints, and trading frictions. The model ensures that enough resources are committed to serve forecasted load, accounting for average transmission losses and the need for ancillary services. Separate regions' commitment decisions are segregated through higher hurdle rates on imports and exports. Trading within a single balancing area, like the various RTO sub-zones, is not subject to any hurdles.
- **Day-Ahead Economic Dispatch Cycle:** the model solves for the optimal level of hourly day-ahead dispatch and trading in 24-hour forward-looking optimization cycles, with 48-hour look ahead periods. Dispatch across the study footprint is optimized based on resource economics. In this cycle, the model also co-optimizes ancillary service procurement for each area. The high hurdle rates for unit commitment are lowered to enable more bilateral trading between balancing areas.
- **Intra-day trading:** the model simulates market activity through one-hour optimization horizons. Trading is assumed to utilize unused transmission, represented as the difference between their day-ahead trading volume and the total contract path limits. No unit re-commitment is allowed due to the non-firm nature of the transactions. Changes to generation availability, such as forced outages, which were not "visible" during the day-ahead cycle become visible during this cycle.
- **Real-Time Cycle:** this cycle simulates the operation of the real-time imbalance markets, such as through EIM transactions. In this cycle, the model can re-optimize dispatch levels and unit commitment decisions for fast-start thermal resources (based on the assumption that the real-time market design allows for unit re-commitment). Deviations from day-ahead forecasts (due to uncertainty) need to be balanced in real-time.

These cycles can take on different assumptions, depending on market structure. In a bilateral setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that can take place between the utilities. In EIM and EDAM+EIM scenarios, all of the cycles are set up to simulate market-wide optimization of unit commitment and dispatch, including the EDAM "reference pass" cycle. In the EDAM case, there would be no hurdle rates between EDAM participants in any of the cycles, allowing the model to optimize both unit commitment and dispatch in the market footprint on both a day-ahead and real-time basis.

Types of Trades and Transmission Reservations Modelled

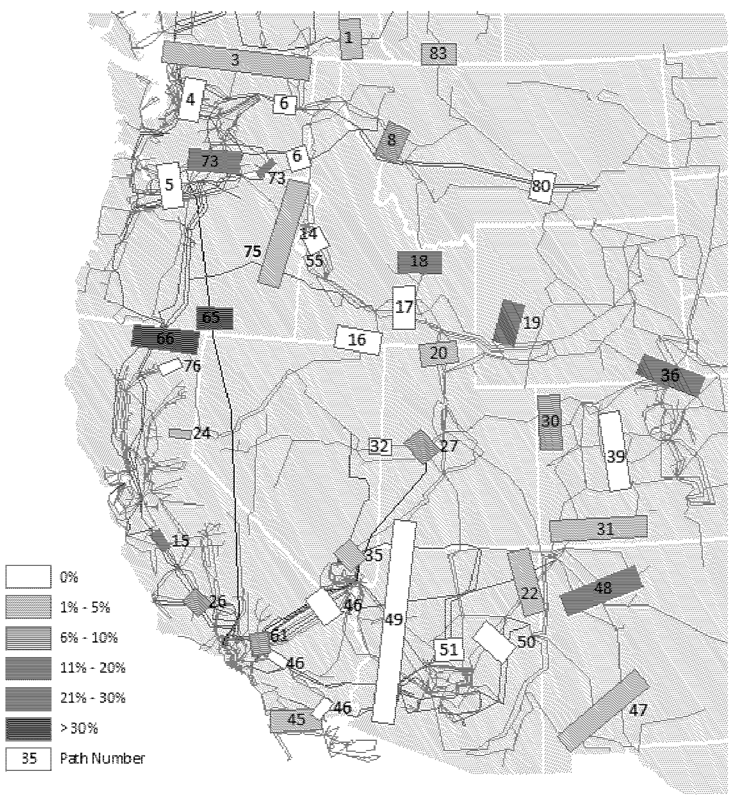
The model simulates the use of different types of contract-path transmission reservations for bilateral trading in DA and RT

- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAAs, at major hubs, or across CAISO interties
- Account for renewable diversity and day-ahead forecast uncertainty vs. real-time operations
- Unscheduled transfer capability released for WEIM trades in real-time



Nodal Simulations Based on Physical Transmission

WECC-Defined Paths Modeled



Limits on the physical transmission system include all the paths defined in WECC Path Rating Catalogue

- Additional transmission paths to represent congestion internal to each BA
- Limits on all paths and constraints reflect what is in the WECC path rating catalogue, unless updated by the study participants

ENELYTIX®
powered by PSO

Power System Optimizer (PSO), developed by Polaris Systems Optimization, Inc. is a state-of-the-art market and production cost modeling tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual RTO and ISO market operations. Such nodal market modeling is a commonly used method for assessing the operational benefits of wholesale market reforms (e.g., JDAs, EIMs, RTOs).

PSO can be used to test system operations under varying assumptions, including but not limited to: generation and transmission additions or retirements, de-pancaked transmission and scheduling charges, changes in fuel costs, novel environmental and clean energy regulations, alternative reliability criteria, and jointly-optimized generating unit commitment and dispatch. PSO can report hourly or sub-hourly energy prices at every bus, generation output for each unit, flows over all transmission facilities, and regional ancillary service prices, among other results. Comparing these results among multiple modeled scenarios reveals the impacts of the study assumptions on the relevant operational metrics (e.g. power production, emissions, fuel consumption, or production costs). Results can be aggregated on a unit, state, utility, or regional level.

PSO has important advantages over traditional production cost models, which are designed primarily to model dispatchable thermal generation and to focus on wholesale energy markets only. The model can capture the effects of increasing system variability due to large penetrations of non-dispatchable, intermittent renewable resources on thermal unit commitment, dispatch, and deployment of operating reserves. PSO simultaneously optimizes energy and multiple ancillary services markets on an hourly or sub-hourly timeframe.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements, subject to various operational and transmission constraints. The model is a mixed-integer program minimizing system-wide operating costs given a set of assumptions on system conditions (e.g., load, fuel prices, transmission availability, etc.). Unlike some production cost models, PSO simulates trading between balancing areas based on contract-path transmission rights to create a more realistic and accurate representation of actual trading opportunities and transactions costs. This feature is especially important for modeling non-RTO regions.

One of PSO's distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which occur at different times ahead of the operating hour and with different amounts of information about system conditions available. Under this sequential decision-making structure, PSO can simulate initial cycles to optimize unit commitment, calculate losses, and solve for day-ahead unit dispatch targets. Subsequent cycles can refine unit commitment decisions for fast-start resources and re-optimize unit dispatch based on the parameters of real-time energy imbalance markets. The market structure can be built into sequential cycles in the model to represent actual system operation for utilities that conduct utility-specific unit commitment in the day-ahead period but participate in real-time energy imbalance markets that allow for re-optimization of dispatch and some limited re-optimization of unit commitment. For example, PSO can simulate an initial cycle that determines day-ahead unit commitment decisions that reflects the constraints faced by, and decisions made by, individual utilities when committing their resources in the day-ahead timeframe. The initial day-ahead commitment cycle is followed by cycles that simulate day-ahead economic dispatch, including bilateral trading of power, and a real-time economic dispatch, reflecting trades in real time (whether bilateral or optimized through an EIM or RTO). Explicit commitment and dispatch cycle modeling allows more accurate representation of individual utility preference to commit local resources for reliability, but share the provision of energy around a given commitment.

TECHNICAL APPENDIX 2

Utilicast

EDAM GAP ASSESSMENT

PREPARED FOR:
NV ENERGY

NVEnergy

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1. EXECUTIVE SUMMARY

This document describes a conceptual business and software approach, project tasks and costs, and a high-level schedule supporting NV Energy's (NVE) entry into the CAISO's Extended Day Ahead Market (EDAM). NVE already participates in the Western Energy Imbalance Market (WEIM), and joining EDAM would allow greater unit commitment optimization and more efficient purchases and sales in the day ahead timeframe.

The proposed EDAM design is the product of a lengthy, actively-involved stakeholder initiative aiming to extend and build upon the regional benefits of WEIM. The primary incremental benefit available in the day ahead time frame is commitment efficiencies, as current WEIM practices can only optimize energy dispatches and short-term commitment. A successful day ahead market requires not only allowing for EDAM-determined day ahead unit commitment, but also addressing transmission service practices that were largely simplified under the WEIM framework. Additional issues that have required careful design throughout the EDAM process are resource sufficiency considerations, congestion rent allocation, greenhouse gas (GHG) modeling, and ensuring equity (the absence of leaning or free riding) between EDAM Entities.

This document is a customary gap analysis assessment, in that it seeks to compare the existing state (NVE current operations under WEIM) and the potential future state (NVE participating in EDAM), identifying any staffing, business process, or software gaps, and establishing the tasks, level of effort, and costs, needed to implement and participate successfully in the Day Ahead Market. This document describes EDAM to the extent that it provides relevant context to understand the scope and tasks needed for NVE's potential EDAM participation.

Some of the tasks or changes that will occur under EDAM participation should be absorbed by current staff. However, there is likely a new need for 7-day a week coverage for bid creation, schedule submission, resource sufficiency evaluation (RSE) and dispatch award management, as well as additional settlements and analytics support, information technology (IT) support, and market policy and management support, both during and after project implementation, which will require additional headcount. EDAM is essentially an additive market, leveraging nearly all of the functionality of WEIM.

1.1 Gap Summary

The main gaps NVE will need to close before joining EDAM focus on day ahead bidding strategies, submission of transmission limits and schedules, day ahead settlements and day ahead transmission customer allocations, reporting and analytics, and third party generation and load coordination. Second order gaps, such as Open Access Transmission Tariff (OATT) changes, updating the tie point meter settlement quality meter data (SQMD), and engaging in market-related seams issues discussions, will also be essential to address. These gaps are cataloged and detailed throughout the body of this document.

The high-level table of gaps is below. These gaps are referenced in the body of this document and help form the basis of the scope items that drive the EDAM Cost Estimating Model.

Table 1 – Summary of Gaps

Gap	Description
Gap 1: • Resource Optimization	**Day Ahead Bidding and Scheduling Strategies** • Impacts of EDAM Resource Sufficiency Evaluation Strategy • Review/Update 2-Day Ahead Gas Nomination Strategy considering EDAM 2-Day Ahead Advisory Results • Create an Imbalance Reserve Bidding Strategy • Load Bidding/Scheduling Strategy
Gap 2: • Resource Optimization • EESC	**Day Ahead Transmission Contribution Processes** • Transmission Registration Process • EDAM Internal and External Intertie Establishment • Submission of available transmission capability • Develop Bucket 3 / Type 4 Unsold Firm and Unscheduled Firm encumbrance processes • Retrieval of EDAM transmission obligations • e-Tagging of awards
Gap 3: • Resource Optimization	**Day Ahead Trading** • Integrating WECC trading processes with EDAM requirements to provide sufficient supply and flexibility
Gap 4: • Resource Optimization • Vendor (PCI)	**Software Updates for submitting Day Ahead Energy (Load and Supply), Imbalance Reserve, and Capacity Bids/Self-Schedules** • Communicate Transmission Contributions and obligations. • Retrieve RSE Test Results – both preliminary and final • Retrieve Day Ahead Awards • Retrieve/Update RUC Bids • Retrieve RUC Awards • Retrieve Day Ahead Results data for analysis
Gap 5: • EESC	**Third Party Load and Generation** • Determining Scheduling Coordinator options for Third Party LSEs and Generators • Determining requirements for Load Forecasts, Metering, Transmission Service Registration, and Day Ahead Load Bidding Options and Requirements • Determine how RSE requirements and penalties are sub-allocated to Third Party LSEs

Gap	Description
Gap 6: • Resource Optimization • EESC • Vendor (OATI)	**Software Updates to support Transmission Contribution tasks** • EDAM Transmission Registration Process and EESC CRN Management • Pre-Day Ahead Market Close TSR Limit Calculations and Submissions • Post-Day Market Run Retrievals and Submissions • Identify Requirements and Design for tools and utilities to assist with these tasks
Gap 7: • EESC • Vendor (OATI)	**Transmission Customer Portal** • Design and Implement Transmission Customer Portal • Conduct Outreach and Training with Customers
Gap 8: • PRSC Settlements • EESC Settlements • Vendor	**Settlement Charge Code and Allocation Business Process Updates** • CAISO Settlement Statement Validation and Invoice Processing • EDAM Charge Code and Transmission Transfer Revenue Allocation Processes • Deferred Energy Report process updates
Gap 9: • NVE	**Credit Requirements and Collateral** • Determine revised EDAM credit limit • Secure collateral and letter of credit prior to EDAM launch
Gap 10: • NVE	**Metering Process and Documentation** • Validate all metering points for conformance with EDAM • Identify all interties and resources requiring updated SQMDs • Develop and submit all required updates to CAISO
Gap 11: • PRSC • EESC	**Information Reporting and Analysis** • Develop reports for anomaly detection and data trending • Assist with Shadow Settlements calculations and reporting • Calculate EDAM market benefits, if elected • Develop real-time dashboards, reports and visualizations
Gap 12: • PRSC • EESC	**Internal Tool Development and Support** • Identify business requirements and needs for tools • Develop internal tools adjacent to OATI and PCI EDAM • Support, maintain and enhance these tools to assist with both PRSC and EESC function
Gap 13: • NVE	**Coordinate updates to OATT and Business Practices** • Ensure schedule and language concurrence in EDAM updates to OATT Business Practices

1.2 EDAM Project Timeline

The EDAM implementation procedure has not been fully validated because CAISO has yet to launch EDAM. PacifiCorp, as the first entrant joining the market with an expected go-live date of spring 2026, will help shape the path for later entrants. Based on current discussions with CAISO, the expectation is that EDAM will have a similar implementation timeline to WEIM.

Based on identifying the number and magnitude of gaps to be closed, regulatory and commission approvals, actions with third-party OATT customers and challenges typical of major CAISO initiatives, a target go-live date of April, 2028 is recommended for NVE. A draft Implementation Schedule is located in **Appendix B**.

NVE is scheduled to complete the Energy Trading Risk Management (ETRM) software migration project in mid-2026. Consolidating multiple trading risk management (TRM) tools will assist in streamlining the integrations among systems and between NVE and the CAISO and help support the targeted cutover date.

1.3 EDAM Project Costs

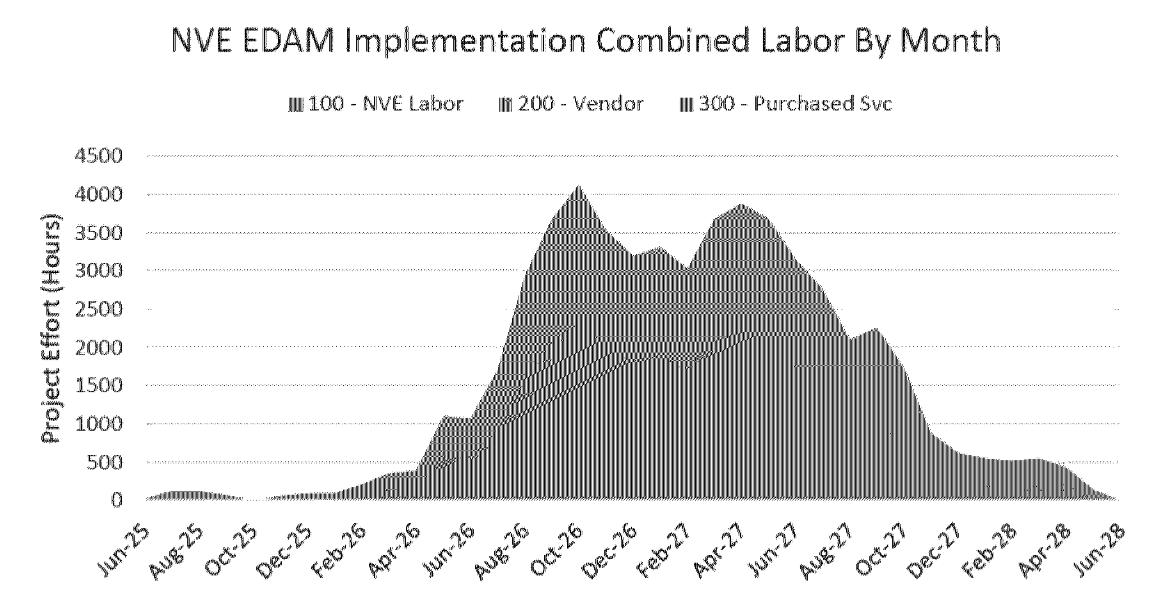
The estimated EDAM Project costs are displayed in Table 2. Costs are estimated for the NVE labor, vendor costs, purchased services including consulting and external legal support, hardware and software acquisitions, licenses and subscriptions (HW/SW), and external fees and contingency. The cost elements are further broken down into capital and operation, maintenance, administrative, and general (OMAG). Budget numbers were estimated using high-level assumptions of the nature and duration of the major phases of project work. As noted, several significant unknowns exist concerning market rules, software requirements, and new processes. To account for this uncertainty, 20% contingency is included.

Table 2 - Estimated EDAM Costs by Category

	NVE Labor	Vendor	Purch Svc	HW/SW	Fees	Total
Capital	**$1,940,000**	**$4,560,000**	**$4,290,000**	**$390,000**	**$1,560,000**	**$12,740,000**
2025	$0	$0	$0	$0	$0	$0
2026	$520,000	$1,140,000	$1,160,000	$60,000	$0	$2,880,000
2027	$1,300,000	$3,420,000	$2,720,000	$330,000	$560,000	$8,330,000
2028	$120,000	$0	$410,000	$0	$1,000,000	$1,530,000
OMAG	**$790,000**	**$0**	**$2,620,000**	**$0**	**$0**	**$3,410,000**
2025	$20,000	$0	$310,000	$0	$0	$330,000
2026	$350,000	$0	$1,140,000	$0	$0	$1,490,000
2027	$340,000	$0	$960,000	$0	$0	$1,300,000
2028	$80,000	$0	$210,000	$0	$0	$290,000
Total Cost						**$16,150,000**

In addition to the overall budget estimate, NVE will need to consider how the effort required to deliver the EDAM Project will align with other initiatives underway. The below figure shows an estimate of the effort by different groups that will be needed throughout the EDAM Project.

Figure 1 - EDAM Implementation Labor



At the outset, primarily business and consulting resources begin to define and organize the project. IT and software vendor resources play a more significant role as the project moves into design. As the new systems are delivered in late 2027, NVE will enter a period of extended training, testing, market simulation and parallel operations, and participation by NVE's end-users begins to ramp up substantially.

Typical utilities are resource-constrained during summer months due to increased operational burdens, however NVE is particularly constrained due to high temperatures and tight supply across the region. The projected implementation labor by month indicates high utilization for internal NVE resources during the summer months. While it is too early in the project to begin resource-smoothing the implementation, this factor will need to be strongly considered when structuring the detailed implementation project plan, and NVE may need to consider offsetting internal labor with vendor and purchased services.

During this time, a significant effort is anticipated to test the new systems, refine business processes, and train the NVE team, who will execute EDAM tasks daily. Joint testing with the

CAISO will begin in Q4 2027 and culminate in intensive efforts during parallel operations and cutover. During this period, it is anticipated that NVE's team will take the lead, both the business units and IT support, and consulting and software staff support will decline as knowledge transfer is completed and NVE prepares for daily EDAM operations.

These costs are detailed in the EDAM Cost Estimating Model in **Appendix A**.

1.4 Staffing Summary, Implementation

Implementing EDAM is a significant undertaking for NVE, requiring a broad range of resources, including deep subject matter expertise from Resource Optimization, Operations, IT, Settlements, and Regulatory teams, alongside dedicated technical specialists and experienced project management professionals.

The complexity, tight timelines, and the need to minimize disruption to essential day-to-day operations underscore the critical rationale for establishing a focused, dedicated implementation team capable of providing consistent attention, coordinating across numerous internal and external stakeholders (including CAISO and FERC), and driving progress effectively.

This dedicated project team should be comprised of external consultants and internal NVE resources. Subject Matter Expert (SME) time will augment the project team for many project tasks. Additionally, some resources, i.e. testing lead, outreach lead, will roll onto the project as appropriate during implementation. The following table provides a high-level view of a dedicated project team with the roles and utilization.

Table 3 – Staffing Summary, Project Implementation

Role	Description	Utilization
Project Manager (Consultant & NVE)	Leads the project team, managing the project plan and budget, and communicating with NVE. Ensures deliverables are on track and aligned with project goals. Ensures NVE's readiness and internal coordination for the EDAM implementation.	• Consultant, 100% • NVE Lead, 100%
Solution Architect (Consultant)	Defines the technical architecture and integration strategy between NVE's systems and the EDAM technologies. Provides technical guidance to the implementation teams to ensure a robust and scalable solution.	• Consultant, 100% • SME Utilization
Technical Lead	Manages the technical implementation efforts, overseeing development, configuration, and integration activities. Provides technical direction and troubleshooting for the implementation team.	• Consultant, 100% • IT Support per major app • Integration SMEs • Environment Management SME

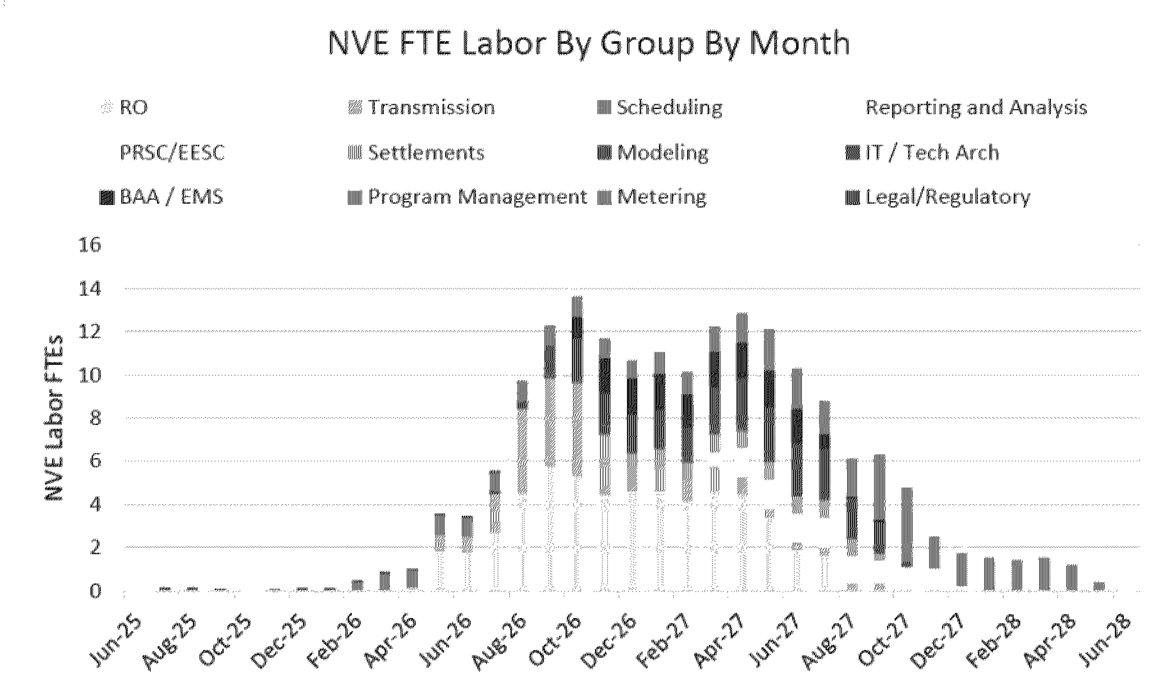
Role	Description	Utilization
Resource Optimization Lead (Consultant & NVE)	Leads the development of bidding strategies and optimization methodologies for NVE's resources within the CAISO EDAM. Collaborates with Merchant teams and technical staff to implement these strategies.	• Consultant, 100% • NVE Lead, 50-75% • SME Utilization
Transmission Lead (Consultant & NVE)	Focuses on the integration of transmission-related aspects into NVE's EDAM participation, ensuring accurate network modeling and congestion management strategies. Provides expertise on CAISO's transmission market rules.	• Consultant, 100% • NVE Lead, 50-75% • SME Utilization
EIM/BA Lead (NVE)	Leads the integration of NVE's Balancing Authority operations with CAISO's systems in the context of EDAM, ensuring proper modeling and imbalance management processes. Provides expertise on EIM and BA rules.	• NVE Lead, 50-75% • SME Utilization
System Operator SME (NVE)	Provides operational expertise on power system dispatch and real-time processes relevant to CAISO EDAM. Supports the design of user interfaces and training for NVE System Operators.	• SME Utilization
Settlements/Metering Lead (Consultant & NVE)	Leads the analysis and design of settlements and metering processes required for CAISO EDAM participation. Ensures accurate data mapping and validation for settlements.	• Consultant, 50% • NVE Lead, 50-75% • SME Utilization
Finance/Accounting SME (NVE)	Provides financial and accounting expertise related to CAISO EDAM settlements and market participation. Analyzes the impacts to the PCI dispatch stacking product, manages the credit/risk impacts, and performs GL configuration and integration.	• NVE Lead, 25% • SME Utilization
Testing Lead (Consultant)	Develops and executes the testing strategy and plan for the EDAM implementation. Leads and coordinates testing activities to ensure system quality and readiness.	• Consultant, 100% • starting ~9 months • SME Utilization
Regulatory SME (NVE)	Provides expertise on CAISO and FERC regulatory requirements, particularly the OATT, related to EDAM participation. Supports regulatory filings and ensures project compliance.	• NVE Lead, 150% • primarily for OATT • SME Utilization thereafter

Role	Description	Utilization
OCM/Outreach Lead (Consultant)	Develops and executes the organizational change management and communication strategy for the EDAM implementation. Supports stakeholder engagement and training efforts for a smooth transition.	• Consultant, 100% • starting ~6 months • SME Utilization

Beyond resource allocation and team structure, key project management concerns encompass complex system integration challenges, ensuring robust data migration and validation, comprehensive organizational change management and training, market simulation and readiness testing, managing regulatory approval processes, and controlling scope, schedule, and budget risks inherent in such larger-scale projects.

The following diagram shows the projected NVE staff requirements by functional area by month for the EDAM implementation.

Figure 2 – NVE EDAM Implementation Labor by Month



1.5 Staffing Summary, Post-Implementation

The EDAM implementation will increase business processes and require additional dedicated headcount. The recommendation for overall headcount is an addition of **8 Full-Time Equivalent (FTE) resources**. Below is a breakdown of which departments these positions would fall under and the new duties that they would be performing.

- **Transmission Business Service:**
  1. Resource will be responsible for supporting a more complex representation of NVE OATT transmission service as part of daily EDAM operations
- **Resource Optimization**
  2. Resource will be responsible for supporting increased day ahead activities and supporting the real time operations during off hours
- **Transmission System Operations:**
  3. WEIM/BA Engineer to support more complex transmission models, system operation changes, and ongoing needs related to the D3, D2, and D1 advisory processes
  4. Operations resource to manage ongoing processes to support DA Advisory Run processes and modify market inputs
  5. Operations resource to lead day-to-day, engineering, and EESC settlements team
  6. Technology-focused resource to assist with internally developed applications, modules, and application integrations. This resource will ensure EDAM-related vendor applications are correctly implemented, utilized, and managed.
- **Settlements:**
  7. Lead resource focusing on EDAM settlement statement validation, EDAM shadow settlements, processing and validating charges received from other WEIM, EDAM or other Market entities, CAISO dispute management, EDAM sub-allocation data validation, EDAM charge codes suballocation, billing transmission customers, TSR billing functions, and transmission customer dispute management. Depending on how the Settlements team is organized going forward, this FTE resource may be split between PRSC and EESC Settlements teams.
- **Analytics:**
  8. Resource focused on reviewing market results for correctness, managing integrated EDAM/WEIM operations efficiently, identifying issues, and suggesting remediations. The resource will assist in refining bidding strategies and designing and prototyping enhanced visualization, reports, and metrics.

1.6 Continuing Costs and Impacts

Maintenance and Upgrade Costs

In addition to the incremental staff noted above, the ongoing costs will consist of annual maintenance fees for products such as OATI, and PCI. These are documented in the "Ongoing Costs" tab of the Cost Modeling Workbook.

Grid Management Charges (GMC)

Participation in EDAM will include the Grid Management Charges (GMC) assessed by CAISO to recover their administrative costs. The GMC comprises various charges, including market services, system operations, bid segment fees, SC trades, and fees, which are determined by a combination of MWh and bid segment or trades through the allocation process, in a manner similar to the current EIM administration fees. In discussions with CAISO, they offer a load volume discount to parties joining EDAM in the first five years. The WEIM charge will no longer be assessed when NVE joins EDAM.

CAISO's GMC estimate is also predicated on entities joining EDAM, and when. The first year projected cost is reasonable, however future years are more speculative and are driven by other entities joining EDAM on schedule. The GMC cost could increase in these years if some entities slip their schedules.

After year 5, the discount would end, and the full GMC charge would be levied. As the phased-in discount eventually phases out, for this analysis, the ongoing cost model assumes paying the full GMC cost in all years, to be conservative. The ongoing yearly incremental GMC cost attributed to EDAM used in this analysis is estimated to be approximately $14.8M as provided by CAISO. Please note that this GMC charge is separate from the CAISO implementation charge, which is captured in the EDAM project implementation costs.

Summary

Cost Element	Rounded Annual Cost
CAISO Fees	$14,819,000
Incremental Staff	$1,568,000
PCI Annual Maintenance	$100,000
OATI Annual Maintenance	$30,000
Grand Total	**$16,517,000**

2. ORGANIZATION OF GAP ASSESSMENT REPORT

2.1 Overview and Approach

NVE requested an identification of the gap between the current state WEIM participation and future state EDAM and an assessment of the costs and effort it would take for the organization to join CAISO's EDAM.

Utilicast conducted a comprehensive current state analysis leveraging data gathering exercises, deep-dive interviews, and on-site workshops to ascertain current state and identify any existing issues.

Utilicast developed a well-defined "EDAM State" from this analysis for NVE, leveraging previous client engagements, subject matter expertise, and insightful interpretations of CAISO's Day Ahead Market Design. This proposed EDAM State strategically aligns with NVE's current business processes and customized approaches, ensuring a clear path forward.

The Gap Assessment Report (and Appendices) represents the culmination of the following work:

- Survey and data gathering
- Interviews with subject matter experts (SMEs)
- Onsite workshops
- Assessing EDAM impacts by functional area
- Preparing an EDAM context diagram
- Developing an EDAM project schedule
- Compiling an EDAM cost assessment
- Conducting an EDAM Gap Assessment presentation

This report includes a narrative of identified gaps and budgetary level estimates of costs and efforts to inform NVE of the overall effort required to join EDAM. Assumptions were made about the type of vendor software updates, enhanced functionality, and any vendor solutions NVE may need to procure; project and ongoing efforts; and the timing of expenditures. It is anticipated that at the outset of implementation NVE will develop a resource-specific staffing plan and define a detailed project schedule.

This report intends to highlight the gaps between current state and EDAM state, and provide an estimate of the effort it will take to close those gaps, regarding resources, technology, and process updates. This report is not attempting to solve these issues; instead, they are being highlighted so that they can be appropriately addressed during the EDAM implementation project.

This gap assessment is also not intended to address the overall benefit of joining the CAISO EDAM market, or perform a qualitative comparison of options between EDAM and Markets+.

This report is organized functionally and may not necessarily align with the current organizational structure. The sections addressed are:

- Resource Optimization
- Transmission Service and Modeling
- Transmission OATT and Counterparty Contracts
- Third Party Load and Generation
- Metering
- Settlements
- Reporting and Analysis
- System Operations and Reliability Coordinator
- Technology
- Legal, Regulatory and Policy

3. RESOURCE OPTIMIZATION

3.1 Current State

In the current WEIM state, the market-facing components of the day ahead scheduling workflow are relatively straightforward, as there is no financially binding organized market participation, simply an WEIM forward base scheduling procedure. The WEIM advanced scheduling, up-to-7 days ahead workflow, is executed primarily to support two objectives:

- Provide generator resource operating plan data required to support RC West reliability requirements
- Provide an accurate and feasible schedule and bid foundation for the WEIM real-time processes

Under the current WEIM state, the day ahead workflow is reasonably straightforward relative to the EDAM, as the WEIM only solves energy imbalances from the Base Schedules.

At a high level, by 10:00 am on the day before Operating Day, aka the "Trade Day", for all 24 hours of the next day, the Day Ahead Resource Optimization (RO) Group submits WEIM Resource Base Schedules, which roughly balance to the Balancing Authority Area (BAA) Day Ahead Load Forecast and the net interchange schedules.

1. At 10:00 am, the CAISO begins execution of the Day Ahead Market.
2. At roughly 1:00 pm, the CAISO publishes Day Ahead Market results, including the Transmission Feasibility Test results.
3. Between roughly 1:00 pm and 5:00 pm, NVE:
    - Ensures all interchange schedules are represented by eTags (Transmission and Resource Optimization)
    - Ensure WEIM generator bids are present for the 24 hours of the next day (Resource Optimization)

NVE Resource Optimization Day Ahead Process – Fuel Considerations

The day ahead process starts at 4 am daily; gas teams are informed of requirements by 5:30 am, the trading deadline for gas. By 10 am, for the next operating day, WEIM entity scheduling coordinators (EESC) and WEIM Participating Resource Scheduling Coordinator (PRSC) must submit all components of the WEIM resource plan. This resource plan is submitted to CAISO via its website.

Gas needs are communicated through three nominations:

1. Day Ahead
2. 4:30 am Same Day

3. A final nomination at 10:30 am. The 10:30 am nomination provides projected gas volumes for each pipeline for the entire gas day.

After the 10:30 am nomination and the receipt of cycle five gas numbers, the Real-Time Generation Desk takes over gas management. At this point, the Generation Desk begins to manage the forecasted gas volumes projected at 10:30 am. If unexpected situations arise, adjustments can be made until 4 pm or by coordinating with the gas team to explore available options.

NVE Resource Optimization Day Ahead Process – Load Considerations

NVE has both participating resources and non-participating resources in the WEIM.

For NVE's resources, NVE goes through a day ahead procedure to prepare and optimize its resources and serve its native load. NVE balances its generation and load based on PCI optimization study (incremental and decremental outputs). Further, within NVE's plan for serving load, NVE balances and serves its two major NVE Load Areas: NVE's North Area (the previous Sierra Pacific Power, SPPC), and NVE's South Area (the previous Nevada Power, NPC). The north and the south systems are jointly optimized for economics while adhering to ancillaries and constraints in both areas.

NVE Resource Optimization Day Ahead Process – PCI Optimization

The following is the list of inputs for the PCI Optimization process:

- Load Forecast:
  - NVE uses Hitachi for their load forecast
- Demand Response Economic Event (only for summer):
  - More details about Demand Response are discussed below.
- Hoover Schedule:
  - NVE receives a certain quota of MWH per week and per month for its share. Based on the load shape, NVE then decides when to use this quota
- Renewable Production Forecasts:
  - This is the small number of Geothermal resources that NVE has under contract.
- VER Forecasts:
  - These are solar and wind resources. These are directly fed from the software UL into PCI around 2 am.
- Gas Prices:
  - These prices are provided via email to the Day Ahead Desk. Gas is traded in TRM at Gas North for Reno, and Gas South for Las Vegas. Initial Gas Prices are provided at 7 am and entered manually into PCI.
- Generation Availability:
  - Sourced from SunNet iTOA, NVE's Outage Management System (OMS)
- Existing Power Transactions:

- Trades are directly interfaced from Allegro to PCI. For Bilateral Day Ahead transactions, the trading and scheduling timeline follows the WECC pre-scheduling calendar, with most days trading for the following day, e.g. on a weekday for the following weekday (Mon for Tue, Tue for Wed). For days preceding weekends and holidays, multiple days are traded and scheduled, e.g. Thursday for Friday/Saturday, Friday for Sunday/Monday, day before holidays, etc.
- Note: NVE plans to replace the Allegro system before EDAM entry.
- ON-Line Transmission Availability:
  - Transmission line capability between NVE North and South areas
- Generation Unit Characteristics Data:
  - Typical generation data including startup costs, monotonically increasing curves, etc.

PCI optimization studies are performed multiple times in this process. All the above inputs are used in the initial run, and the results are obtained and verified to be reasonable. The optimization studies incorporate both reliability and operational constraints. These optimization runs also consider resource adequacies, generation availability, contractual limitations, gas limitations at the north hub, etc.

As the next step, the Day Ahead Desk operator uses an uncertainty reserve calculator developed in accordance with Energy and Environmental Economics (E3) to calculate additional flex reserves that are required for VER uncertainty. These values are then used as input to PCI for a second round of PCI optimization study. PCI optimizes the AS and allocates different types of AS most economically. Results are obtained after reasonability checks, troubleshooting, and reruns (as necessary). This second run is generally the most important and final run unless gas prices, load forecasts, or any other significant changes happen in the grid.

NVE Resource Optimization Day Ahead Process – Resource Plan Submission

The resource plan is submitted by 10 am. It is comprised of:

- WEIM Base Schedules of WEIM Participating Resources
- Energy Bids (applicable to WEIM Participating Resources only) - Energy Base Schedule
- Reserve Requirements and Available Balancing Capacity (ABC) Bids. These include:
  - AS to meet NERC/WECC contingency reserve requirements (i.e. 3% of gen and 3% of load for NERC/WECC)
    - Spin – Spin Base Schedule
      - FRR (subset of Spin) - Spin Base Schedule
    - Non–Spin (all CR that is not FRR) - Non-Spin Base Schedule
  - Additional flexible or uncertainty reserves to account for VERs from E3 tool
    - This will be an input to the PCI pre-optimization process
  - Available Balancing Capacity (ABC) bids
    - RegUp – ABC Up Base Schedule

- RegDn- ABC Down Base Schedule

The day ahead power traders will e-tag the resources according to the csv files published by the day ahead planning team. The day ahead power traders use Allegro to aggregate tie line data from bilateral trading activity and the csv file resource schedules. The tie data is sent to the transmission scheduling department. The Day Ahead Desk enters VER, Hoover, and transmission limits in the csv file and emails the files to the traders. Hourly north-to-south and south-to-north transmission study results are obtained from PCI and sent to accounting. Accounting for NVE North-South split is verified through csv files. The day ahead desk then transfers all the data to the Real-Time Generation Desk for real-time follow-up the next day.

NVE Resource Optimization Real-Time Gen Process

The day ahead traders work closely with real time traders daily through scheduled meetings, email communications, and ad-hoc conversations. Through these conversations and information gathering, they perform key actions to complete the day ahead activities. Real time operators sometimes have to perform real time trading if they are short or have to meet any resource adequacy needs.

The WEIM T-57 and WECC T-20 tagging deadlines are critical parts of this process. In this case, the real-time traders purchase the energy for the hour and enter it via the e-Tag system. Transmission is reserved for a full hour. The NVE WEIM Entity and the transmission scheduler are also informed in this process.

When bilateral trade opportunities arise in real time after Cycle 5 has been published, the traders coordinate with the Generation Desk to assess the trade's impact on gas management. The PCI software system used for native load pricing identifies which units would be increased or decreased to support the trade, guiding the decision.

Real Time Generation Desk operators also update WEIM Base Schedules and Bids for all resources based on market and resource conditions and the latest resource information. Real time traders use the CAISO load forecast from the CAISO Base Scheduling Aggregation Portal (BSAP) to make base scheduling and trading decisions. All these activities require a significant degree of manual effort to move data among spreadsheets and systems to keep things in sync.

Currently, the EESC team manages all aspects of the WEIM Resource Sufficiency Evaluation (RSE) for all three real-time test timeframes.

Demand Response

NVE currently has a Demand Side Management (DSM) Program Portfolio. Within this portfolio, NVE manages a combination of residential, commercial, and industrial demand response programs. Currently, most demand response assets in this program directly control weather-dependent loads, such as air-conditioning load management. Most system-level economic demand response events and dispatches happen in summer; there are also some occasional system-level emergency events for distribution reliability. In SPPC's territory, emergency dispatch can be supplemented by irrigation load control governed by the IS2 Tariff, a non-DSM program. The current emergency dispatch capability is approximately 200 MW (thermostat program). Current economic optimized phased dispatch is approximately 150 MW. Currently, NVE gives customers an energy market rebate for the energy they use.

NVE is also expanding its programs, focusing on controlling non-weather-dependent loads and behind-the-meter batteries. New programs launching in 2025 include residential and fleet-managed charging programs. These new programs are discussed in detail in NVE's 2024 IRP.

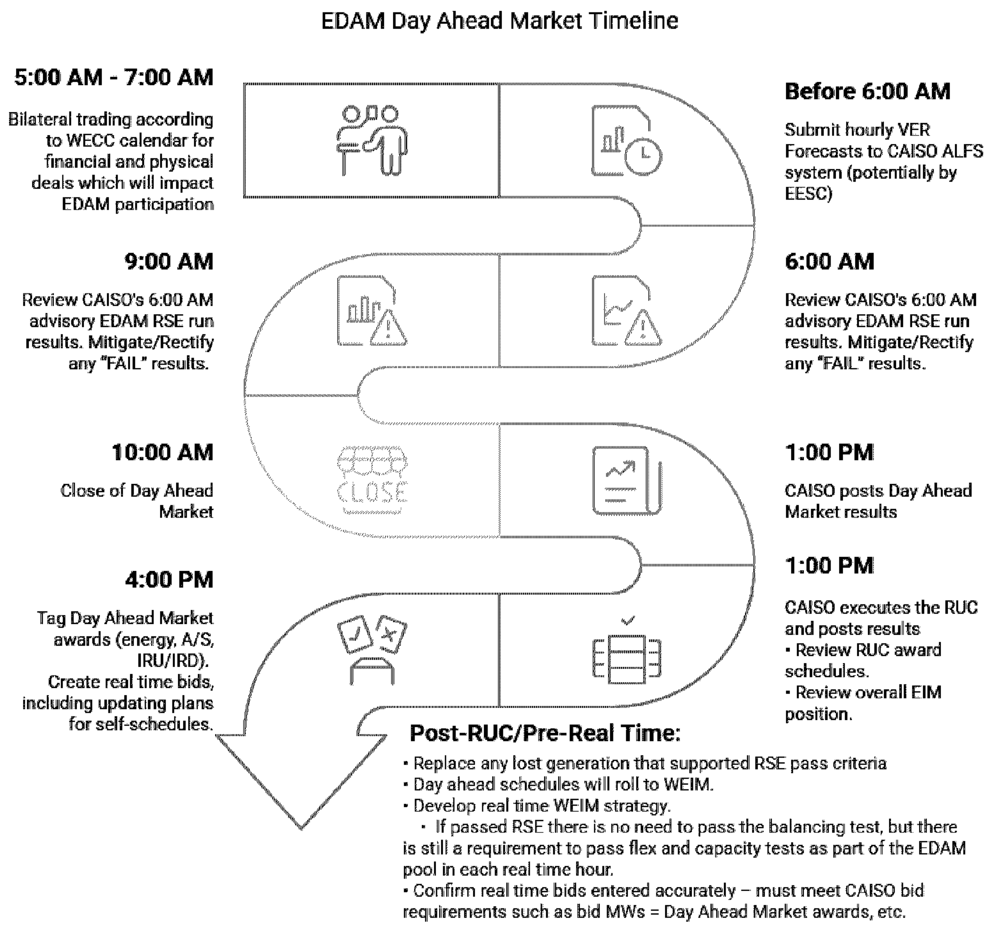
The load shape submitted to CAISO accounts for the demand response amount in the current WEIM scenario.

NVE is currently replacing its existing Demand Response Management System. The upgrade phases, design considerations, and EDAM impacts are discussed in the next section.

3.2 EDAM State

Day Ahead Timeline

Figure 3 - EDAM Day Ahead Market Timeline



The EDAM workflow can optionally start with the output of the CAISO's "high quality" 2-day ahead (or 3-day ahead on weekends) process. This non-binding process aims to support EDAM participants in their fuel procurement. This 2-day ahead process seeks to obtain a market-based estimate of the generation schedules for use-limited resources such as gas or hydro. These may be inputs to the PCI process, depending on their quality.

Following the close of the Day Ahead Market at 10:00 am, NVE will iterate through the steps below. This set of steps could be repeated multiple times in part or whole.

- Refresh generation and transmission outage conditions.
- Refresh the latest CAISO or self-provided load forecast (final update posted at 9:00 am).

- Refresh to latest VER forecasts (final update posted at 9:00 am).
- Update EDAM RSE transfers (import or export) based on bilateral obligations.
- Determine EDAM bidding and scheduling strategy:
  - Strategy decisions may be supported by PCI optimization software, which will be executed within this timeframe.
  - This includes ensuring that the strategy meets EDAM RSE requirements.
- Submit/Update EDAM load self-schedules and bids.
- Submit day ahead transmission contributions by bucket type.
- Submit day ahead transmission interchange schedules.
- Submit/update EDAM generation self-schedules and bids and input Contract Reference Number (CRN#) where applicable.
- Effectuate process to offer unsold firm Available Transfer Capability (ATC) to EDAM (Bucket 3/Type 4 – by EESC)
- Effectuate process to offer unscheduled non-firm ATC to EDAM (Bucket 2/Type 4 by EESC).

2-Day Ahead (2DA) Process on TD-2:

- The TD-2 process will be initiated daily after the Day Ahead Market results are published at 1:00 pm. All participants are expected to provide bids, but the results will not be financially binding. Advisory results will be available by 5:00 am on TD-1 (day ahead day).
- From a systems interface perspective, the TD-2 process is exactly the same as the day ahead process outlined below, but the results are advisory only.
- The TD-2 process results will indicate advisory generation resource commitments that can be used to adjust unit commitment plans, establish an initial position in natural gas, and perform various other analyses.

For this gap assessment, it is assumed that the TD-2 run will be analyzed and time is scoped to integrate the results into the NVE Resource Optimization process and tools, but it is not yet clear how much effort or use of the TD-2 will be efficient.

A significant difference between WEIM and EDAM is that the Day Ahead Market is financially binding in EDAM. Day Ahead Market preparation will likely begin consistent with the WECC bilateral trading schedule, which has not been modified to accommodate Day Ahead Market participation. Weekend and holiday trading and scheduling practices will continue while the EDAM will run each day independently, 365 days a year. Day ahead traders will refine their position with subsequent market obligations and transactions in mind by the start of the CAISO's Day Ahead Market execution at 10:00 am on TD-1.

The most significant changes in EDAM relate to modifying NVE's current processes and tools to create bid submissions a day ahead of the operating day, rather than a Base Schedule Plan. With all transactions settled, traders must be mindful of the subsequent interpretation of their deals in the market. Bids and self-schedules will be submitted for all registered resources. NVE will also need to submit load bids and self-schedules.

Per CAISO's current EDAM market design, NVE will be no longer be able to participate in CAISO MRTU Intertie transactions at NVE's TSP borders with CAISO The current design for CAISO border intertie bidding in EDAM is that transmission that is "part of" an EDAM Entity (e.g. the EDAM Entity sells service as part of its transmission service provider function) will not be eligible for MRTU intertie transactions (IFM and HASP) by any transmission customer/scheduling coordinator. This may impact NVE Resource Optimization and other NVE transmission customers and change how trading and scheduling works at critical intertie locations. At a high-level, intertie bidding at NVE TSP Borders will be replaced with Transfer System Resources with CAISO, which is explained in more detail in the Transmission Service and Modeling section. NVE may be able to continue intertie bidding at other transmission service providers' borders with CAISO. If NVE is interested in CAISO MRTU intertie bidding for NVE transmission service provider ties with CAISO, NVE would need to pursue discussions with CAISO and advocate for EDAM market design changes.

Resources

For thermal resources, bid creation will likely follow the same basic formulas to create generally cost-based offers with some strategy adjustments. Key considerations for strategy will be whether to dictate (self-schedule to run or outage/no-bid to enforce a no-run condition) thermal resources or whether to make resources with long startup times market committable / de-committable. Allowing displacement of baseload thermal generation, which a utility would otherwise typically run for its own needs, with imports is one of the significant benefits delivered by the Day Ahead Markets and could provide NVE significant benefits if:

- Fuel management can accommodate "unexpected" commitments and decommitments. In this context, "unexpected" means based on the 2DA results, if they can be trusted, or based on the Day-Ahead results at 1:00 pm.
- Plant operations can accommodate "unexpected" commitments and decommitments, especially potential increased cycling of thermal resources. During implementation, NVE should investigate the value of this effort.
- Joint ownership agreements can accommodate it and coordination with joint owners to allow market-optimizable commitments are successful. During implementation, NVE should discuss with its partners the value of participation and the effort and risk of allowing the market to commit/de-commit these resources.

Gas Resources

The cost and GRDT definitions for gas resources will be similar to the WEIM and the decision to bid into the Day Ahead Market should make managing market decisions on these units easier since NVE will have additional lead time on the commitments/notification that the units are not scheduled to run to support market needs. Though the conceptual approach is similar, it was identified that a technology refresh of PCI bidding strategies is needed.

As NVE prepares to participate in the CAISO Extended Day-Ahead Market (EDAM), establishing robust gas forecasting and trading processes is critical for ensuring economic and operational efficiency. Natural gas remains a primary fuel source for many of their generation assets. Gas forecasting tools enable NVE to anticipate their fuel needs based on expected generation dispatch, ambient weather, and market signals, aligning gas procurement more closely with actual system requirements. The forecasting must reflect realistic and committed fuel availability to avoid penalties or dispatch issues.

Gas Forecasting

To meet the demands of gas forecasting and trading in the CAISO EDAM environment, NVE can leverage software like Aligne (by FIS) and PCI's Gas Management solutions. Aligne provides a comprehensive suite of Energy Trading and Risk Management (ETRM) capabilities with strong support for gas logistics, nominations, storage management, and real-time tracking of pipeline constraints. It also enables integration with market data feeds and scheduling systems to align gas procurement with power market operations.

PCI's gas capabilities are tightly integrated with their broader energy optimization suite, allowing for coordination between gas procurement and power scheduling. PCI's gas module supports nomination workflows, forecasting, and real-time balancing, tailored to utilities operating in organized markets like CAISO.

Since Gen Trader is already used for unit commitment and dispatch optimization, adding PCI's gas module would enable a unified view of generation and fuel needs. Gas forecasts can be derived directly from Gen Trader's output, while Gen Manager can coordinate the dispatch with gas availability and nomination constraints. This tight integration allows gas forecasts and nominations to automatically reflect updated generation plans, ensuring that CAISO day-ahead bids submitted via Gen Manager are fuel-aware and operationally viable.

Using Aligne in parallel or as a supplement can provide advanced trading, risk analytics, and support for more complex gas market strategies, especially when NVE manages storage assets or engages in more sophisticated bilateral transactions. In both scenarios, aligning the gas workflow with the CAISO EDAM timeline, from early forecast runs to nomination deadlines, is essential for accurate, reliable market participation.

Gas Storage

Since a significant portion of NVE's generation comes from natural gas-fired power plants, it is prudent to analyze gas storage capabilities. The availability and price of natural gas directly impact the operational costs of these units. Gas storage allows NVE to purchase and store natural gas when prices are lower and withdraw it during periods of high electricity demand or when gas supply from pipelines is constrained or prices are high. Understanding their storage levels, injection/withdrawal capabilities, and the broader gas market ensures NVE can fuel its generators reliably and cost-effectively, informing their bidding strategies in the EDAM and real-time markets to maximize revenues or minimize costs while meeting load obligations. This analysis also helps manage the risk of natural gas price volatility and supply disruptions, which can significantly impact electricity market outcomes.

To perform this analysis, the approach would consist of the following:

1. Develop a fleet burn analysis for representative days, i.e. spring, summer, winter, to develop a baseline.
    - Focus on normal usage, not necessarily shocks from a 'bad' historic day, although that information is valuable for scenario building.
2. Document the timeline and procedure for procuring gas, specifically, what is bought at 2DA, what is bought DA and scheduled by 7 am, etc.
3. Detail the current issues and concerns with the gas procurement in a WEIM market
    - Include current mitigations, such as intraday market or burning it for negative LMPs
4. Detail gas procurement risk factors associated with EDAM participation
5. Develop scenarios for the EDAM participation
    - Start with a one-day trading package (e.g., Tuesday trades), followed by a discussion of what would be different from the multi-day packages.
    - Create sensitivities of things that could go wrong based on what the gas procurement team worries about.
        - Standard limits to pack / draft
        - When NVE might be more limited due to previous days packing and drafting
        - OFO or other shocks
    - Discuss what dump options there are for gas or power

This analysis can be built inside a spreadsheet model to allow for what-if scenarios and multiple modeling options. These scenarios and options would serve as the start of a gas storage decision and could be used as the basis of a business case, if needed.

Variable Energy Resources (VERs)

For a VER to be biddable into the market, it must be capable of being curtailed. Most VER providers also provide a method for accounting for curtailing resources. The best practice is to have a Supervisory Control And Data Acquisition (SCADA) system directly interface with the plants to send curtailment signals. Any market dispatch that calls for a reduction in output will be sent from CAISO's Automated Dispatch System (ADS). Then the VER tool will be utilized to send instructions to the plant's Distributed Control System (DCS). NVE currently has the capability to send Dispatch Operating Targets (DOTs) to each VER and can only send electronic signals to a relatively small number of VERs to curtail output. It could be beneficial to implement that capability for all VERs.

While VERs will be counted at the forecast value in the RSE, VERs are not required to be self-scheduled to the forecast in the Day-Ahead Market. Many VER operators do not bid/schedule to the full forecast output. It is generally believed that VER operators are attempting to lock in day ahead Locational Marginal Prices (LMPs) for a block of output while reducing their exposure to real time LMPs for potential reductions in the forecast. This has the general effect of raising day ahead LMPs as less "free" generation is available to the day ahead solution. Whether NVE, as an entity primarily load-serving and not merchant, would choose such an approach requires more investigation during the implementation. Increased bid participation of the VER fleet will support NVE in passing the RSE.

Lastly, NVE should look into optimizing the available/allocated energy for the Hoover resource. Optimizing Hoover will require developing an approach with PCI, internal and external stakeholders, and consultants.

Non-Participating Resources

Currently, there are non-participating resources that NVE schedules. Maximizing resource participation is key for achieving EDAM benefits but may entail additional costs. NVE will investigate having some of these resources fully participate in the EDAM market. This will first require executing a more detailed cost-benefit analysis and technical feasibility analysis than supported by this gap assessment. There are four options/paths that NVE can look into for EDAM participation for current non-participating resources:

1. Full day ahead/real time participation similar to a WEIM Participating Resource, requiring the following:
   - Automated EMS to the Plant controller signal that is at least a 5-minute target MW/time, with a possible full AGC-style integration, depending on NVE EMS approach
   - Revenue quality CT/PT/Meter with 5-minute data measured at, or adjusted to, the high side of the GSU and inclusive of station service
   - Communication paths to retrieve revenue quality meter data (RQMD) register reads/accumulators daily with storage and backup
   - Full SQMD plan submitted to CAISO
2. Day ahead only bids with real-time self-schedules, requiring the following:
   - Plant DCS with the ability to follow an hourly schedule provided by 1 pm DA
   - Revenue quality CT/PT/Meter with 5 or 15-minute data measured at, or adjusted to, the high side of the GSU and inclusive of station service
   - Communication paths to retrieve RQMD register reads / accumulators daily with storage and backup
   - Full SQMD plan submitted to CAISO
   - Follows cross-hour ramps, but AGC is not strictly necessary
3. VER dispatch curtailments, requiring the following:
   - Plant DCS has the ability to follow an hourly scheduled day ahead curtailment or a real time curtailment, which is potentially limited to manual initiation but strongly desired automation and likely not requiring full AGC control.
   - Revenue quality CT/PT/Meter with 5 or 15-minute data measured at, or adjusted to, the high side of the GSU and inclusive of station service
   - Communication paths to retrieve RQMD register reads / accumulators daily with storage and backup.

- Full SQMD plan submitted to CAISO

4. Continue to base/self-schedule only
    - No changes. Can be grandfathered.

NVE has performed an initial analysis of the current WEIM participating resources and the third-party resources with PPA. The following provide a synopsis of the work to be done.

- Third Party Resources with Power Purchase Agreement (PPA):
    - As per the analysis, NVE would like to make twenty-five of the third party PPA resources select Option 1, i.e. full day ahead and real time participation.
    - These resources can be economically curtailed as per EDAM requirements. Each contract analyst reviews the contract and settles it in a spreadsheet when there are curtailments. Utilicast will work with NVE to convert similar sub-allocations to process automatically through the settlements system. Utilicast will also work with NVE to get a list of curtailable resources through EMS, then model these resources and build preliminary estimates for any equipment changes needed. Work includes ensuring the resources are AGC capable, have governors in place, and are equipped with proper meters, and submission of SQMDs to CAISO.
    - For other resources that cannot be economically curtailed, NVE wants to continue to base/self-schedule them. For those resources, NVE is in the process of verifying the contracts in place to see if any of these resources can participate in full day ahead and real time. Utilicast will help NVE with this effort as necessary.
- WEIM Participating Resources:
    - NVE desires all resources currently participating in the WEIM to select Option 1, i.e. full day ahead and real time participation. For the units that are not currently bid in WEIM, Utilicast will work with NVE and PCI to strategize on how to make these economically participate in day ahead and real time. Utilicast will also coordinate with NVE RO and other teams to understand equipment deficiencies and improvements needed for these resources to participate in full day ahead and real time.
    - Some of the work includes ensuring the resources are AGC capable, have governors in place, and are equipped with proper meters and submission of SQMDs to CAISO. A detailed list of resources, equipment changes, and other work will be estimated, and the cost estimate will be available in the cost model worksheet.
    - For the units currently bid into WEIM, Utilicast will work with NVE and PCI to ensure they are properly optimized for day ahead and real time scenarios, and if any corrections are needed.
    - There are a total of 38 resources in this category.

Load Forecast

NVE will need to develop a strategy to determine what portion of the load forecast to self-schedule versus bid into the Day-Ahead Market. This load forecast is obtained from CAISO. Any portion of the load forecast not cleared in the Day Ahead Market will be considered in the Residual Unit Commitment (RUC) process. Metered loads above or below the Day Ahead Market cleared quantity will be served at real time LMPs, similar to how deviations from the Load Base Schedule are settled today.

The day ahead RSE will consider load at the CAISO forecast, so bid-in and self-scheduled supply must meet the forecast load plus uncertainty in the form of Imbalance Reserve bids.

NVE will also need to determine if they want to continue using the CAISO load forecast or a self-provided or third-party load forecast. Each has its own set of pros and cons:

<u>CAISO Load Forecast</u>

- Pros:
  - **Market Basis**: This is the forecast that the market clearing engine uses to determine schedules and prices. Bidding aligned with the CAISO forecast is crucial for scheduling resources and managing imbalance risks.
  - **Reliability Focus**: The CAISO forecast is developed with grid reliability in mind, incorporating system-wide factors and potential contingencies
  - **Data Consistency**: Forecast is based on the data and models that CAISO has access to and uses for system operations
- Cons:
  - **Limited Granularity/Local Detail**: The CAISO forecast is system-wide or for larger sub-regions. It may not fully capture the specific, localized load characteristics or unique factors within NVE's balancing authority area (BAA).
  - **Methodology Opacity**: While CAISO provides information about its forecasting methodology, the specific models and real-time adjustments may not be entirely transparent for participants, making it harder to predict potential biases.

<u>Self-Provided Load Forecasts (Independent/Third Party Forecasts)</u>

- Pros:
  - **Potential for Higher Local Accuracy**: Third-party forecasters or NVE's internal forecasting can tailor models to NVE's specific service territory, incorporating local weather data, customer types, distributed energy resources, and other factors that might provide a more accurate picture of NVE's actual load
  - **Independent Analysis**: Provides a valuable independent check against the CAISO forecast
  - **Strategic Insights**: Analyzing the potential difference between a third-party forecast and the CAISO forecast can inform bidding strategies, allowing NVE to capitalize on

predicted market imbalances (e.g., if a third-party forecast predicts higher load than CAISO, NVE might bid more resources).
  - **Scenario Planning**: Third-party models can be more flexible for running various scenarios (e.g., extreme heat events, impacts of new large loads) to understand potential risks and opportunities.
- Cons:
  - **Not the Market Driver**: The market clears based on the CAISO forecast, regardless of how accurate a third-party forecast might be. Significant deviations from the CAISO forecast in bidding can lead to resources not being scheduled or facing significant imbalance penalties. NVE currently forecasts native load and then adds a value to represent the aggregated non-native load forecast to use in Balancing Authority level studies. If NVE were to self-provide the whole Balancing Authority level forecast, then very accurate and granular non-native load forecasts would be needed.
  - **Development and Maintenance Cost**: Building and maintaining a sophisticated third-party forecasting capability requires investment in data, software, and expertise.
  - **Data Alignment Challenges**: Ensuring that third-party models are using comparable or correctly synchronized data with CAISO's inputs can be complex.
  - **Risk of Over-Reliance**: Over-reliance on a third-party forecast that consistently differs from the CAISO forecast can lead to suboptimal bidding outcomes.

In practice, many EDAM participants will use both types of forecasts, with the CAISO forecast as the baseline for bidding and scheduling and the third-party forecasts to gain deeper insights into their expected actual load, identify potential discrepancies with CAISO's view, and inform their risk management and optimization strategies. The goal is to bid effectively into the market driven by the CAISO forecast while also being prepared for real-time conditions informed by independent analysis.

Demand Response

As part of the DERMS upgrade process, NVE is going through a multistage upgrade process. Phase 1a (completed), improved the security of device communications for the existing DERMS. The DERMS team is currently finalizing the design of phase 1b, which is scheduled to go live in the second quarter of 2026. This phase will replace the existing DERMS software.

Phase 2 of DERMS project is going through the design phase currently. Phase 2 adds enhanced control of additional devices and enables new grid services by aggregation of DERs. These services may include energy arbitrage, frequency regulation, and voltage support. This phase will also enable these DER aggregations to possibly participate in the CAISO day ahead and real-time markets by integrating DERMS and Unit commitment software of PCI.

Phase 2 of this upgrade process, when completed, will help NVE to improve automation and decision making regarding optimal economic dispatch of DERs. As such NVE is closely monitoring the requirement definitions. These phases will likely be completed before NVE enters EDAM and therefore the design and requirements should keep EDAM in focus so that NVE can participate with these enhanced functionalities in the EDAM market. NVE is expecting DERMS phase 2 to go live in 2028.

In EDAM, NVE can set up a strategy for bidding on resources in their demand response program. These resources can be offered and potentially receive commitments in a viable timeframe (1:00 pm TD-1). However, the specific registration approaches, e.g. price responsive vs. reliability, metering, telemetry requirements, and rules for counting in the RSE and day ahead clearing need more definition. Specifically, NVE needs to evaluate the following:

- Current program utilization and characterization
- How existing contracts would process curtailments
- Whether tariffs and associated contracts could be updated to have more market-oriented definitions and approaches
- Metering and telemetry for existing programs

NVE must evaluate how these properties relate to the market registration rules. NVE has not traditionally participated in these programs in WEIM since the program requirements are incompatible with WEIM timelines. Whether these programs can be accommodated in the day ahead timeframe is worth investigating. Utilicast will work with NVE in designing and implementation of phase 2, to enable the DERs to participate in CAISO EDAM and RT markets.

EDAM/DAME Imbalance Reserve Product

- Stakeholders and the CAISO have developed an Imbalance Reserve (IR) product for the Day Ahead Market Enhancements (DAME) initiative. IRs will be a biddable product in both the upward and downward direction. Resources can provide IRs if they are dispatchable on a 15-minute basis. Contributions will be determined based on their 30-minute ramping capability. The CAISO will procure IRs across the EDAM footprint to help meet the uncertainty requirement.
- The EDAM will procure IRs in the IFM co-optimized with energy and the CAISO BAA footprint AS. Any resource that is dispatchable on a 15-minute basis would be eligible to bid in IRs. An IR award comes with a must-offer obligation to provide economic energy bids in the fifteen-minute market matching the award.
- IR bids are submitted via the SIBR system. Therefore, NVE will likely deliver IR bid payloads via PCI software.
  This additional EDAM market product should be incorporated into the overall day ahead and RSE strategy.

EDAM Resource Sufficiency Tests

For resource sufficiency, the CAISO will conduct a binding EDAM RSE at 10:00 am before running the Day Ahead Market. There will also be advisory EDAM RSE runs at 6:00 am and 9:00 am, with non-binding test results available on demand for each EDAM Entity. The consequences of failing the EDAM RSE will be imposed on the BAA experiencing the shortfall.

The policy on allocation of RSE responsibilities to LSEs within the BAA, and how the cost of failure is distributed, are reflected in the respective OATTs and are still being determined by early EDAM Entities. PacifiCorp and Portland General Electric have taken somewhat different approaches. Additional discussion of these topics is provided in the EESC section.

The EDAM RSE ensures the CAISO and EDAM Entities can meet their BAA obligations before participating in the EDAM through a test determining whether each BAA has sufficient supply and reserves to meet forecast demand, plus a CAISO-derived uncertainty MW amount.

The EDAM RSE application will use submitted supply to optimally determine if an EDAM BAA can achieve a feasible operating schedule given its obligations. The EDAM RSE will test an EDAM entity's ability to meet its BAA requirements in each of the 24 hours of the Day-Ahead Market run and that it has the flexibility to ramp between the requirements in each hour. The following key inputs are considered for determining each EDAM BAA's EDAM RSE requirement capacity target:

- **Forecasted Hourly Demand**: Either the CAISO day ahead hourly load forecast or optionally self-provided. The pros and cons of CAISO and other third-party load forecast should be evaluated for accuracy during implementation.
- **Imbalance Reserves**: Ensures each EDAM BAA will have sufficient reserves to cover its upward and downward uncertainty requirements from Day-Ahead to FMM. This is a considerably larger uncertainty than the current WEIM Flex uncertainty.
- **Flexibility Requirement**: Assesses ramping capability by testing whether an EDAM BAA has a feasible schedule, ramping between hourly requirements across the 24-hour day.
- **Ancillary Service Requirements**: Tests whether an EDAM BAA has self-provided sufficient capacity (that does not overlap with supply made available to the EDAM) to meet its AS requirements.

The following key inputs determine each EDAM BAA's EDAM RSE incremental or decremental <u>supply capacity</u>. This supply capacity is expected to exceed the EDAM RSE requirement in each hour:

- Resource supply bids
  - Including normal generator resources (gas, hydro, etc.)
  - VER resource supply bids
- Firm energy Imports and exports
- Load modification and demand response programs
- Bilaterally traded RSE requirements

The consequences of EDAM RSE failure are twofold:

1. Direct dollar impacts are primarily assessed after the fact via settlement penalties. The penalties increase across three EDAM RSE failure tiers, i.e., minor failures result in smaller or no cost.
2. Inside the market functions, the failing EDAM BAA will be forced to participate in the WEIM RSE tests as a standalone BAA, as opposed to the EDAM BAAs that pass the EDAM RSE and participate in the WEIM RSE test as a pool or group.

EDAM Resource Sufficiency Obligation Trading

- RSE requirements can be traded between EDAM BAAs through a specific EDAM Transfer termed a 'Type 3 Transfer System Resource'.
- This transfer functionality may require a method for communicating excess supply between EDAM participants.

Greenhouse Gas (GHG) Accounting and Reporting

EDAM's GHG accounting and reporting framework utilizes the same resource-specific approach in WEIM. When offering output to serve California demand, scheduling coordinators (SC) for resources located in BAAs outside of California will submit bid adders consisting of a GHG bid capacity (MW) quantity and a GHG price ($/MWh). These bid adders reflect the SC's willingness to make output from the resource available to serve California demand and capture the additional cost of compliance with California's GHG regulations. When determining total imports to a GHG regulation area, the CAISO's optimization utilizes both the GHG bid adder and energy bid to determine which resources are to be attributed to serving California demand. If a resource does not submit a bid adder or the GHG bid capacity is zero MW, the CAISO does not attribute the resource to serve California demand.

NVE can still control whether they want to be subject to GHG compliance regulations and whether their resources are attributable to any GHG area through the utilization of a bid adder. The ability to choose whether to take on additional compliance liability is the same in EDAM as in WEIM, so NVE should not need to make any EDAM-specific changes related to GHG treatment.

Because NVE chooses to utilize bid adders and allows their resources to be attributable to current GHG jurisdictions, it is recommended that NVE continue to closely follow and participate in future GHG stakeholder processes to accommodate other states' programs to understand the financial and additional reporting and compliance requirements that multistate programs will require.

3.3 Gaps

3.3.1 Staffing

The Day-Ahead Market is run 365 days a year. NVE has maintained a business day approach to staffing and continued to use a WECC trading calendar style approach to Day-Ahead participation, i.e. setup Thursday for Friday and Saturday; setup Friday for Sunday and Monday, with all the remaining Day Ahead Market submissions being taken on by the Real-Time team.

It is assumed the Real-Time staff would continue to be cross-trained on day ahead processes and shoulder the workload on weekends and holidays. Given the increased workload, NVE should consider a long-term staffing increase in day ahead Resource Optimization functions of approximately 1 FTE, and possibly an on-call rotation to support the real time team during nights and weekends. Additional analyst support may also be needed, and is documented in the *"Reporting and Analysis"* section of the gap assessment.

If real time supports some or all of the Day-Ahead Market trading activity during weekends and holidays, it will be important to consider driving consistency between software tooling and business processes across the day ahead and real time groups. This would lower the training barrier workload for a real-time trader in addition to performing day-ahead tasks.

3.3.2 Business Process

New or substantially updated processes will be developed to support the CAISO's EDAM 2-day ahead and day ahead functions, mainly executed by the day ahead staff. Embedded in these new processes will be newly developed strategies.

Impacts from Two-Day Ahead (2DA) Workflow

This non-binding market execution will result in advisory schedules for the 24 hours of the target operating day. NVE Resource Optimization may retrieve those generator schedules from the CAISO CMRI system. These advisory schedules may be incorporated into the overall natural gas position and trading strategy prior to the gas trading window.

Impacts from Day Ahead (DA) Workflow

- **Resource Optimization will need to develop Day Ahead bidding and scheduling strategies.** The WEIM objective of balancing WEIM Base Schedules to the CAISO's load forecast is no longer applicable.
  - The notion of WEIM Base Schedules is eliminated in EDAM and is replaced by day ahead bids and self-schedules.
  - EDAM Participants are required to be resource sufficient but are no longer required to 'balance'. They can bid or self-schedule load equal to, less than, or greater than the forecasted load. They also have the option to bid or self-schedule generation, which may differ from their total load bids.
  - This bidding or self-scheduling exercise should be assessed with a defined risk tolerance.
  - Purchase decisions and evaluation of whether NVE is surplus may be based on factors or strategies different from those used today. For example, if NVE is Resource Sufficient, it may be more driven by RSE evaluation, allowing NVE to transact anticipated surpluses or deficits with the market, and bilateral transactions

would not be needed. Conversely, if NVE is not Resource Sufficient, the bilateral market will be a key consideration. Ultimately, NVE will likely utilize a mixture of bilateral and market transactions day ahead.
    - Reporting, analysis, and visualization tool opportunities are discussed further in the *"Reporting and Analytics"* section of the gap assessment.
- **Resource Optimization and BAA will need to develop a day ahead transmission contribution approach.**
    - Firm transmission may be associated with energy bids and/or contributed to the EDAM to support passing of EDAM RSE (more discussion in the *"Transmission Service and Modeling"* section of the report). Resource Optimization will need to develop a strategy for their transmission portfolios and resource sufficiency needs.
    - The business process, strategy and technological needs to support the transmission contributions are significant.
- **Resource Optimization will need to develop an EDAM resource sufficiency strategy.**
    - In parallel with the EDAM bidding optionality, NVE must ensure that they meet or exceed EDAM RSE requirements. The EESC owns this process, but Resource Optimization will primarily provide enough supply flexibility to pass. How a BAA tests, with third party impacts, will be managed by a Resource Optimization group will need to be defined.
    - The EDAM Resource Sufficiency strategy must co-exist and be co-optimized with bidding and the self-schedule strategy described above.
- **DA will supply hourly VER Forecasts to CAISO ALFS.** These hourly 'actual' forecasts will be used by the CAISO RSE and RUC evaluations. Provision of these 'actual' forecasts would be in addition to any VER Day Ahead Market Bids/Self-Schedules.
- **Business Processes will need to be updated** with the changes to the RSE, an RSE strategy created, and training on the changes for all impacted staff (Merchant, Entity, Settlements).
- **DA Trading:**
    - The DA Trading function is necessary for NVE to provide sufficient supply and flexibility. Integrating the WECC trading processes with the EDAM requirements will require significant work.

Impacts from Greenhouse Gas (GHG) Accounting and Reporting

The current NVE GHG accounting and reporting process is comprehensive, as described in the current state section. NVE should continue to dedicate staff time to monitoring and participating in GHG CAISO stakeholder processes and conversations to track any upcoming changes.

Ensuring staff are aware of compliance obligations and that those costs are accurately reflected and incorporated into the bid strategy will be necessary. No additional staff on top of those who currently perform the GHG policy and compliance functions and the bidding function will be needed as a function of EDAM participation.

3.3.3 Software Applications

This EDAM Gap Assessment assumes that NVE stays with its current vendor, PCI, and does not engage in competitive selection to purchase new EDAM tools. NVE's primary market and reliability software vendors, OATI and PCI, have stated they plan to support the EDAM functionality fully.

Software functionality for EDAM will include:

- General vendor EDAM updates
- Transmission contribution
- Transmission registration and submission updates through the TSR Buckets/Types.
- Submission of day ahead bids, self-schedules and associated transmission, and all Bidding enhancements
- Consideration of inter-scheduling coordinator trades or updates to ETRM capabilities to reflect fixed for floating swaps
- Load Forecast RC Submission
- RC data updates (VER & load forecast updates)
- Pre-DA market close functions, e.g. evaluate available firm transmission and contribute available unobligated firm
- Post-DA market run, e.g. retrieve Awards, DA market results, and DA transmission obligations
- Potential support for how IRU/IRD is considered through the WECC trading timeline

The current PCI software can also be optimized to improve the organization of the data inside the tool, including:

- Leveraging PCI GenManager's rule-based engine to define clear and well-documented bidding rules aligned with current market conditions, operational constraints, and strategic objectives.
- Implementing naming conventions and tagging to improve organization and traceability, and establishing a regular review process to optimize bidding strategies and avoid future complexity creep.

NVE may want to explore optimizing its share of energy from Hoover to enable efficient participation in the Day-Ahead Market. Designing and implementing the software and tools to allow for this would be a considerable effort.

3.3.4 Software Interfaces

Based on the EDAM workflows outlined above, the following new interfaces will likely be required:

- Submit hourly VER Forecast data to CAISO ALFS

- Submit day ahead energy (load and supply), Imbalance Reserve and capacity bids/self-schedules
    - Include transmission Contract Reference Number (CRN) data where applicable
- Manage CRN availability
- Communicate firm transmission contributions to SIBR and/or to the EESC
    - Depending on whether EESC implements Transmission Customer Portal, may need to build an interface between bidding software and EESC Transmission Customer Portal
- Retrieve RSE test results, both preliminary and final
- Retrieve day ahead IFM and RUC Awards
- Retrieve and update RUC bids
- Retrieve Day Ahead Results data for analysis and reporting
    - EDAM's Day Ahead Market will produce various data/reports that are not present in WEIM
- Retrieve inputs and results from CAISO for RSE
- Process tagging requirements for day ahead awards.

4. TRANSMISSION SERVICE AND MODELING

4.1 Current State

In the current WEIM paradigm, NVE uses firm (unsold) and non-firm (unscheduled) ATC to facilitate WEIM transfers. This contributed WEIM transmission is seen to have little or no value so close to the operating hour; therefore, the contribution does not create a revenue burden. This paradigm is shifted under EDAM.

4.2 EDAM State

Changes to the operation of transmission assets is probably the most significant new functionality that EDAM introduces. In EDAM, a new type of optimized day ahead EDAM transfer between EDAM Entities (or between EDAM Entities and CAISO) is introduced, effectuated through a new intertie resource called the Transfer System Resource (TSR). EDAM Entities will need to define interties between their BAA and with other adjacent EDAM Entities, CAISO, and non-EDAM Entities. In EDAM, EDAM Entities and CAISO are referred to as EDAM Internal Interties, whereas EDAM Entity and non-EDAM Entity are known as EDAM External Interties.

A table of mapped EDAM Interties for NVE has been provided below, based on an assumption that NVE joins EDAM in 2028, and considering other announcements of entities joining EDAM. NVE EDAM Entity function will need to work during the project state to confirm these interties with other adjacent EDAM entities.

Table 4 – Mapped NVE EDAM Interties

Intertie	Adjacent Entity (TSP/BA)	EDAM Intertie Type	Intertie Resource for NVE EDAM Entry
Hilltop	BPAT	EDAM External Intertie	System Resource or TID
Mead230	WALC	EDAM External Intertie	System Resource or TID
Mead500	WALC	EDAM External Intertie	System Resource or TID
Midpoint	IPCO	EDAM External Intertie*	System Resource or TID
BCTTAP230	WALC	EDAM External Intertie	System Resource or TID
Summit	CAISO	EDAM Internal Intertie	TSR
Marble	CAISO	EDAM Internal Intertie	TSR
Silverpeak	CAISO	EDAM Internal Intertie	TSR
Gonder IPP	LA	EDAM Internal Intertie	TSR
Gonder PAV	PAC	EDAM Internal Intertie	TSR

Intertie	Adjacent Entity (TSP/BA)	EDAM Intertie Type	Intertie Resource for NVE EDAM Entry
HA500	CAISO	EDAM Internal Intertie	TSR
Crystal	LA	EDAM Internal Intertie	TSR
McCullough 230	LA	EDAM Internal Intertie	TSR
McCullough 500	LA	EDAM Internal Intertie	TSR
Navajo	LA	EDAM Internal Intertie	TSR
Eldorado	CAISO	EDAM Internal Intertie	TSR
Nwest	CAISO	EDAM Internal Intertie	TSR
Mercury	CAISO	EDAM Internal Intertie	TSR
RedButte	PAC	EDAM Internal Intertie	TSR
Amargosa	CAISO	EDAM Internal Intertie	TSR
APEX	LA	EDAM Internal Intertie	TSR
MOHAVE500	CAISO	EDAM Internal Intertie	TSR

*Assumes IPCO joins EDAM after NVE; however, if IPCO joins before or coincidentally, Midpoint would represent an EDAM Internal Intertie and location where TSR is used.

As shown in the table, NVE has several different possible EDAM External and EDAM Internal Interties.

The interties shown generally map to those interties where NVE's contiguous transmission system is connected to another entity, however, depending on Resource Optimization transmission rights that Resource Optimization offers, NVE EDAM Entity may be able to establish other EDAM Internal Interties that are remote to its system if its merchant or one of its transmission service customers has transmission rights across an EDAM External Intertie / Non-EDAM Entity transmission service provider (TSP) to another EDAM Entity. Utilicast did not identify any NVE merchant transmission rights or customer rights that would initially be candidates for establishing an EDAM Internal Intertie across a non-EDAM Entity TSP, however, this may be something that NVE might be interested in the future.

Further, it should be noted that some of the EDAM Internal Interties noted in the table above represent existing WEIM ties where NVE is both the TSP and the BAA at that tie (e.g. HA500), however, some ties listed above represent locations where NVE is only the TSP (e.g. NAVAJO500). Ties represented in WEIM today that are TSP-TSP require agreement between NVE WEIM Entity and other WEIM Entities, and will similarly require coordination and agreement in EDAM if ties are represented from the TSP-TSP perspective in EDAM. NVE will need to work closely with its adjacent WEIM and EDAM entities to determine how these ties will be modeled.

Effectuating EDAM transfers between EDAM Entities (or with CAISO) at EDAM Internal Interties is made possible by the EDAM Entity offering firm transmission capacity, through various contribution types. In EDAM, the contribution of firm transmission capability is tied closely to modeling various types of firm transmission service and associated contracts. This contractual representation of EDAM is a fundamental change compared to WEIM. Although most firm transmission reservations are on a long-term yearly or monthly basis, there are still OASIS-based transmission sales in the day ahead and real time timeframe which will compete with EDAM use in certain circumstances. This competition for resources will need to be resolved, and at least some transmission assets provided to the EDAM market to capture the economic benefit of the system-wide optimization of resources. To facilitate the new transmission service requirements, EDAM Entities will need to work through various processes for transmission contract registration, transmission contribution, scheduling, and revenue allocation processes.

For ease of analysis, the CAISO divided up the transmission needed for EDAM into three groups, termed "buckets." Recently, CAISO also refined its categorization of transmission contributions / TSRs into four types of TSRs: Type 1, Type 2, Type 3 and Type 4[1].

EDAM Transmission Registration Process

Prior to EDAM implementation, the CAISO will host a process that allows TSPs and transmission customers to register different types of transmission service with CAISO. EDAM Entities should expect to register various transmission service types, including pre-OATT/grandfathered rights, long-term firm point-to-point, conditional firm, and network transmission service contracts. The registration process will allow the EDAM market to transact using transmission Contract Reference Numbers (CRNs), a construct similar to OASIS AREFs. The CAISO's transmission contract registration process shall allow an EDAM Entity to associate a single unique CRN with multiple underlying like-kind transmission service reservations, rolled up to unique OASIS Transmission Paths and/or CAISO Transfer Locations (e.g. a specific POR/POD). The registration process will collect key attributes of each CRN, similar to the way the CAISO's Generation Registration Data Template (GRDT) captures key generator information. Each CRN path is required to register key attributes such as: CRN Entitlement (MW), CRN Type, Physical Right Level (TOR/ETC/OATT1/OATT2), SC, Transfer Location, Source, Sink.

It is expected that EDAM Entity TSPs will need to define processes to map and roll up OASIS Transmission Service, TSNs, and NITS Scheduling Rights to CRNs, on an automatic basis to capture and map changes to long-term transmission reservations (e.g. REDUCTIONS, TSR Reliability Limits) and new short-term transmission reservations to CRNs. The need to capture TSR Reliability Limits within the CRN rollup process may be increasingly important in the future, especially as FERC Order 881 OASIS implementation processes may result in firm ATC values becoming more variable in the 0-240 hour time horizon. These new systems will likely require new management and

[1] Described in CAISO's EDAM Business Requirements Specification https://www.caiso.com/documents/business-requirements-specification-extended-day-ahead-market.pdf

automation processes within the Open Access Transmission software (e.g. webTrans) paired with EESC software (e.g. webEDAM EESC).

Finally, as part of EDAM transmission registration processes, NVE will need to work with transmission customers who have any transmission service rights that wheel across the NVE system and who may desire to use its transmission outside of NVE EDAM (e.g. in SPP Markets+). At the time of this Gap Assessment, the technical means for utilizing transmission service outside of EDAM is still being determined; however, these issues are expected to be clarified and likely resolved by the time NVE joins EDAM.

EDAM Transmission Contribution Methods (Transfers at EDAM Internal Interties)

Through the EDAM market design processes, EDAM final proposal and filed CAISO tariff, CAISO identified three principal groupings of transmission contributions to support EDAM transfers at EDAM Internal Interties and three sub-groups within Bucket 2. Recently, with the introduction of the updated EDAM BRS 1.4, they introduced Type 1, Type 2, Type 3, and Type 4 TSRs. Type 1 – 4 TSRs mostly overlap the existing Buckets, however they aren't exactly aligned. For continuity, both Buckets and Types will be referred to in the following section. In order of importance, these are:

1. **Bucket 1 (Type 3 TSR):**
   The Bucket 1 category of transmission available for EDAM transfers is the transmission tied to the BAAs' external supply resources needed to support its day ahead RSE. A BAA that has LSEs with contracted supply in another BAA participating in EDAM will be supported by a TSR. Prior to the Day Ahead Market, the balancing authority will communicate to the CAISO the transmission capability available at each of its interties that will be available in the Day Ahead Market and support a transfer at that intertie location. These transfers support the EDAM RSE of AS and/or bid capacity transferred from one EDAM BAA to another.

2. **Bucket 2:**
   Transmission customers self-schedule and release transmission capacity for EDAM transfers. The Bucket 2 Pathway 1 schedules will impact both the RSE and the market clearing. Pathways 2 and 3 are primarily inputs to the market clearing.

   a. **Pathway 1 (Type 1 TSR)** – Transmission customers self-schedule their transmission rights (represented as CRNs) with bilaterally traded energy between EDAM BAAs.
   b. **Pathway 2** (**Type 2 TSR)** – Transmission customers release unneeded firm transmission rights directly to CAISO to be used in EDAM in exchange for direct allocation of transfer revenue.
   c. **Pathway 3 (Type 4 TSR if unscheduled, Type 1 TSR if scheduled)** – Transmission customers that do neither can still schedule energy and transmission after the 10:00am EDAM Market runs as needed, but EDAM may have utilized the

unused transmission as available for market optimization which may result in real-time redispatch.

3. **Bucket 3 (Type 4):**
EDAM Entities make any unsold and/or unscheduled firm transmission capacity available for EDAM optimization.

For clarity, a definition of the different TSR Types 1 – 4 are found below:

1. **Type 1:** Bilateral energy transactions between transmission customers scheduled into SIBR by 10:00 day ahead
    a. Transactions are associated with specific Transmission Customer Scheduling Coordinator(s) (TCSC)
    b. Transactions are associated with CRN, and count towards RSE
2. **Type 2:** Capacity from transmission customers that release for EDAM Transfers their transfer rights at a transfer location by 9:00 AM
    a. Associated with TCSC
    b. Not RSE Eligible
    c. Not associated with CRN
    d. TCSC is eligible to receive transfer revenue
3. **Type 3:** RSE-eligible transfer capacity released by EDAM Entities
    a. Associated with EESC
    b. RSE eligible
    c. Not associated with CRN
    d. Use cases include AS transfers or bid capacity transfers between EDAM BAAs
4. **Type 4:** Non-RSE eligible transfer capacity released by EDAM Entity TSP
    a. Associated with the EESC (EDAM Entity TSP)
    b. Not RSE Eligible
    c. Not associated with CRN

Other EDAM Import / Export Schedules (Imports / Exports at EDAM External Interties)

Generators and LSEs in an EDAM BA, as well as transmission customers wheeling across EDAM Entity TSPs shall also be responsible for self-scheduling their imports / exports into and out of EDAM areas on EDAM External Interties. Similar to the existing paradigm in the WEIM, these imports and exports will be represented on CAISO System Resources or Transaction ID (TIDs). Transmission customers shall be able to schedule imports and exports on a day ahead basis at EDAM External Interties in SIBR using a System Resource with or without a CRN, however a CRN shall be used if the transmission customer wants to obtain higher scheduling priority for its transaction in EDAM.

Intertie Constraints (ITC) Registration and other special Transmission Constraint Modeling and Operational Needs

CAISO continues to offer Intertie Constraint (ITC) functionality in EDAM. For EDAM, ITCs will be used to ensure the dispatch of multiple TSRs is within the limits provided by NVE. ITCs registered for EDAM will represent constraints in the day ahead optimization, but not the real time optimization. To the extent that NVE needs to model constraints in EDAM for day ahead similar to reasons for pre-existing ITCs in WEIM, e.g. to constrain multiple dynamic ETSRs to be within Northern System Import Limits to constrain total imports or exports system-wide, NVE will need to work to develop and register ITCs for EDAM. At the time of this Gap Assessment, based on information provided by NVE, it seems reasonably possible that NVE may need to consider ITCs for TSRs for any EDAM Internal Interties injecting/withdrawing from NVE's Northern System, e.g. for the combination of PACE Gonder – Pavant, LA Gonder – IPP, and potentially, Idaho Power Midpoint.

While ITCs allow for modeling certain types of transmission constraints, they cannot resolve all transmission constraint modeling issues NVE faces. Of particular emphasis, in the current NVE WEIM participation, NVE must plan and coordinate in advance for outages of the Harry Allen – Robinson Summit 500kV line. Outages of this line in WEIM today result in NVE's BAA separating into two areas (essentially, the pre-NVE SPPC BAA and NPC BAA areas). As NVE's WEIM model only represents a single BAA and cannot be subdivided into two areas, NVE currently implements CAISO's Operating Practice 2720 to request a market separation. During the market separation, no WEIM dispatches are sent to any NVE participating resources, and NVE's responsibilities to meet WEIM requirements are limited. In addition, NVE's settlement team must work with CAISO to use administrative prices for settlement purposes during the market separation. Concerning NVE's future EDAM implementation (projected in 2028), NVE's Greenlink West projects should be in service before NVE joins EDAM. With Greenlink West operational, NVE will have additional 500kV facilities between its Northern and Southern systems, and the likelihood of needing to separate from EDAM may be reduced. Even with these additional facilities, NVE indicates that it may still be possible that certain maintenance outages could place NVE in a similar situation as it faces today, and it needs to implement market separation processes from EDAM. Implementing market separation processes in EDAM may become more complex due to changing data submission requirements. As such, it is recommended that NVE work with CAISO during the implementation project to determine processes and parameters for how a market separation from EDAM would need to occur, and whether any new transmission constraint modeling options would allow NVE to facilitate a market separation.

Other Transmission Modeling Considerations

The Southwest Intertie Project North (SWIP-North) line is scheduled to be energized in mid 2028, with a plan to turn over some transmission entitlements on this line to California ISO operational control, using CAISO's Subscriber Participating Transmission Ownership (PTO) model.

Utilicast is aware that the transmission facilities modeled with the CAISO Subscriber PTO model may require special attention and treatment, and may require unique modeling approaches in certain aspects of transmission modeling and scheduling, which could impact current WEIM and future EDAM participants. Utilicast recommends that NVE review CAISO's current Subscriber PTO model and any available documentation on scheduling and operational aspects, and analyze whether incremental project work items should be included within an EDAM implementation project to ensure compatibility between the Subscriber PTO model for SWIP-North and the NVE EDAM design.

CAISO is currently working through similar aspects of the Subscriber PTO model for the SunZia line, and has stakeholder processes attempting to address operational and scheduling aspects of SunZia as a Subscriber PTO. This may be a good reference for NVE to explore and analyze possible impacts of the SWIP North line on NVE and within the NVE EDAM model.

EDAM Timeline

A good starting point for defining the EDAM process Day Ahead timeline for transmission contributions for EDAM transfers, as well as day ahead imports and exports comes as follows:

1. **Before 10:00am Bucket 1 & Bucket 2: Pathway 1 (Type 1 & 3 TSRs) and System Resources/TIDs:**
   - In the day ahead, NVE Resource Optimization will self-schedule Type 1 TSRs and System Resources/TIDs. This will cause these self-schedules to be reflected in the RSE and the market clearing. Additionally, Resource Optimization will inform the NVE EDAM Entity of any EDAM transfers of AS or bid capacity for RSE. Simultaneously, the NVE EDAM Entity (BAA / TSP) will submit Type 3 TSR self-schedules and capacity; Type 1 TSR and associated CRN transmission usage limits to CAISO as part of the overall process for stating the transfer limits, and CAISO will validate the schedule against the CRN Entitlement MW.
2. **Before 9:00am Bucket 2: Pathway 2 (Type 2 TSRs):**
   - Transmission customers may release transmission capacity directly via their CRNs in SIBR for CAISO to optimize in EDAM. A transmission customer release of CRN capacity shall also be fed back to the EDAM Entity TSP to ensure that any release of CRN capacity is not also released as part of Bucket 2, Pathway 3 (Type 4 TSRs).
3. **At 10:00am Bucket 2: Pathway 3 (Type 4 TSRs):**
   - TSP make available to the market unscheduled (non-firm) transmission capacity to EDAM for optimization. This will be communicated to CAISO's SIBR system by the EDAM EESC, together with Bucket 3 (Type 4) TSRs discussed below.
4. **At 10:00am Bucket 3 (Type 4 TSRs):**
   - TSPs make the final release of unsold firm transmission capacity available to EDAM for optimization. This will be communicated to CAISO's SIBR system by the EDAM EESC.
5. **After the 10:00am close of Day Ahead Market, Bucket 2: Pathway 3 (Type 1 TSR):**
   Transmission customers can self-schedule energy with associated transmission and CRNs as needed for bilateral trading and balancing, after the Day Ahead Market close.

The NVE EDAM Entity (BAA / TSP) shall continue to submit Type 1 TSR and associated CRN transmission usage limits to CAISO as part of the overall process for stating the Transfer Limits, and CAISO will validate the schedule against the CRN entitlement MW to ensure there is enough CRN capacity.

EDAM will affect transmission customers (or PRSC) and Transmission Service Providers (TSP or EESC) differently and these changes are shown separately below

New Processes for Transmission Customers and PRSC

Process changes affecting the PRSC and transmission customers include registering all transmission rights, submitting day ahead energy bids, self-schedule energy and associated transmission, and contributing excess rights. These processes are highlighted below:

- **Registration of transmission:** NVE Resource Optimization and other transmission customers will work with the EESC to register applicable transmission contracts associated with the NVE transmission system as CRNs in EDAM in the Transfer Data Template (TDT). CRN definitions in the TDT shall be uploaded into the Masterfile and scheduled in SIBR. This process shall be used to establish the baseline of transmission ownership for each transmission owner that can be used to meet the RSE. The registration of transmission as CRNs will likely require staffing support from existing Resource Optimization transmission contract staff to build new processes for regularly reviewing (e.g. quarterly) of CRNs to ensure all of its transmission contracts are properly registered and accounted for. NVE Resource Optimization and other transmission customers may want to build online or offline tools to help manage CRNs.

- **Submission of bids with firm transmission:** NVE Resource Optimization and other transmission customers may accompany day ahead energy bids and self-schedules with transmission rights submissions via CRNs into SIBR. These submissions will be to Bucket 1 (TSR Type 1) resources in SIBR and/or System Resource or TID or resources. This will be a new process for the NVE Resource Optimization group.

- **Self-scheduling and associated transmission:** NV resource Optimization will submit self-schedules for all generation that require minimum energy outputs to meet certain grandfathered or firm bilateral contract obligations. These generation obligation self-schedules could be accompanied by transmission reservations needed to support interchange. Import transmission reservations accompanied with neighboring EDAM Entities' generation self-schedules must also be included. Self-scheduling will be a new process for the NVE Resource Optimization group.

- **Contribution of transmission rights:** NVE Resource Optimization will be able to contribute unneeded or unused firm point-to-point transmission rights via Bucket 2: Pathway 2 (TSR Type 2) to support EDAM transfers. These rights will be used in the EDAM optimization process, which awards EDAM transfers to contributed transmission rights. The ability of

EDAM to optimize transmission will allow for a more complete market optimization. It will ensure that transmission rights owners are compensated (through transfer revenue) for the use of their contributed transmission. While NVE will need to confirm this as part of OATT revision processes, it is expected that any resulting EDAM transfer resulting in incremental dispatches from NVE Designated Network Resources will not need to be supported by a temporary undesignation of DNRs, which is similar to existing WEIM processes in place today. The process of contributing and settling utilized transmission rights will be new processes for the NVE Resource Optimization group.

New Processes for Transmission Service Providers (EDAM Entity)

Impacts to EDAM Entity TSPs include the registration of transmission contracts, Transfer System Resources, submission of EDAM transfer transmission contributions, self-schedules for TSRs and other import/exports, as well as mitigation of any RSE requirements with transmission capacity contributions.

- **Registration of transmission contracts:** NVE EESC will need to establish processes for the registration of transmission contracts as CRNs in the TDT / Master File for all transmission customers. NVE will need to establish processes to map different types of transmission service (e.g. firm, network service, legacy rights) to different CRN types and set up automated processes in Transmission Open Access software (e.g. webTrans) to map transmission service AREFs to CRN. NVE EESC may need to establish systems to allow its transmission customers (e.g. Resource Optimization function) the proper visibility to CRNs and their Entitlement MW to aid in transmission customer self-schedule and transmission contribution process flows. NVE will also need to identify and work with transmission customers with wheeling transmission service rights who wish to withhold their transmission service from EDAM.

- **Registration of Transfer System Resources (TSRs):** NVE EESC will be required to define and register different TSR types in the TDT / Master File. While any Type 3 and Type 4 TSRs can only be submitted by the EDAM Entity, Type 1 and Type 2 TSRs can be defined and submitted “on-the-fly" via TC submissions directly in SIBR, so there may be limited amount of TSR registration that is required for NVE with respect to these types. At the time of this analysis, and assuming CAISO, LDWP, and PacifiCorp join before NVE, there are multiple ties that NVE would have with future EDAM entities (CAISO, LDWP and PacifiCorp ties). As such, it is expected that NVE will be able to establish multiple Type 4 TSRs for its EDAM implementation. To support Type 4 TSRs, NVE EDAM Entity will need to calculate and release excess (unused, unsold, and un-contributed) firm transmission capacity for the close of the Day Ahead Market and final binding EDAM RSE and optimization run at 10:00am. NVE EESC will need a process and tools to calculate the transmission capacity that can be released, likely a derivation of calculations carried out in Open Access Transmission software (e.g. webTrans and OASIS). NVE will need to work to determine if any changes to existing non-firm release timelines will need to be adjusted to allow for Type 4 submissions. Specifically, NVE will need to examine whether NVE should continue or modify its practice of allowing unscheduled firm to be released as non-firm at 12:00/noontime WECC preschedule.

- **EDAM Transfer / Import / Export Submissions:** EDAM Entities shall be required to facilitate various types of transmission customer and entity submissions to EDAM for transmission contributions, self-schedule imports and self-schedule exports. Further, NVE EESC will likely need to offer capabilities to any transmission customers who are not an SC with CAISO to submit various Day Ahead submissions into SIBR, including TSR Type 1, System Resources and TIDs, capabilities to release CRN capacity for Type 2 TSRs, as well as capabilities for transmission customers to offer transmission capability to effectuate Ancillary Service Transfers and/or bid capacity transfers between EDAM Entities utilizing Type 3 TSRs.

- **RSE result retrieval and submission of transmission capacity:** The Entity will need to retrieve RSE test results and help ensure that the EDAM BAA will pass RSE at the final binding test (10:00am). At a minimum, the Entity will need to review interim test results and develop a process for submitting additional transmission capacity to aid the BAA's RSE position. The retrieval, review, and submission of transmission capacity will be new processes for the EDAM Entity.

- **Transmission Constraint Modeling and other special operational considerations:** The Entity will need to work internally and with CAISO to develop and register any Intertie Constraints (ITC) necessary to ensure special transmission limits are respected in EDAM. These ITCs should be coordinated with any ITCs that NVE uses in the real-time market. In addition, the Entity should work with CAISO during its project to ensure it has a strong understanding of any processes and operational procedures that need to be implemented to ensure that NVE is able to carry out any market separation processes necessary in the event of major North to South transmission line outages that separate its BA into two areas.

4.3 Gaps

4.3.1 Staffing

New and additional transmission-related tasks will be required for EDAM. These tasks include transmission registration, registration review (annual or semi-annual), contribution of transmission rights capacity, self-scheduling (including associated transmission), contribution of unsold and/or unscheduled firm transmission, retrieval of RSE results, and process for adjusting bids and transmission associations if RSE results fail.

It is assumed that the existing DA staff within NVE EESC and NVE PRSC functions will be able to absorb most of these tasks on a long-term basis post-implementation. Given the increased complexity of Transmission Service representation in EDAM, NVE should consider a long-term staffing increase in its Transmission Services / OASIS Administration functions of approximately 1 FTE.

During the implementation, NVE should be prepared to allocate the equivalent of 2 FTE from its equivalent Transmission Services / OASIS Administration functions to support developing and implementing the Transmission Service Model into EDAM. NVE could choose to augment or substitute portions of these project resources with external contractor support.

Additionally, it is expected that approximately 1 dedicated FTE from NVE Resource Optimization who has a background in Resource Optimization's transmission portfolio, scheduling, and tagging should be allocated to the implementation project to support these processes. These NVE merchant roles may be able to be combined with other resource needs identified in the Resource Optimization portion of the report. NVE could choose to augment or substitute portions of these project resources with external contractor support.

4.3.2 Business Process

The following Business Process changes will need to be made:

1. Registration of transmission contracts (PRSC/EESC)
    a. Initial registration, including registration of select legacy contracts associated with Valmy and Nellis Air Force Base
    b. Periodic evaluation of registered transmission
2. Establishing and coordinating EDAM Internal Interties with CAISO, LDWP and PacifiCorp, and any other adjacent EDAM Entity registering those ties and TSRs and developing coordinated processes for their use (PRSC/EESC)
3. Working with adjacent EDAM and WEIM Entities to determine the approach EDAM Internal and EDAM External Interties using BA/TSP-BA/TSP ties vs. TSP-TSP ties
4. Development and maintenance of the Transmission Service Model/Market Transmission Management business rules into EESC software (EESC)
5. Development and registration of any Intertie Constraints (ITC) as well as any special operational procedures/processes to handle major transmission outages (e.g. major North to South 500kV line outages separating NVE Northern and Southern areas)
6. Development of a strategy, and submission of contributed rights capacity, including NVE Resource Optimization's transmission portfolio (PRSC)
7. Submission of self-schedules and the associated transmission (PRSC)
8. Submission of firm ATC (EESC)
   Submission of non-firm ATC (EESC)
9. Retrieval of RSE results (EESC)
10. Reviewing RSE results, and adjusting bids and transmission to ensure pass (PRSC/EESC)

4.3.3 Software Applications

PRSC Software Impacts

For the most part, the new transmission contribution PRSC functionality will be handled in planned EDAM merchant-side software enhancements (discussed in the Day-Ahead Process section of this report). The Transmission processes/tasks that fall on the PRSC staff align very closely with larger Day-Ahead Market tasks such as day ahead energy bids and self-schedules. The EDAM transmission registration process will largely be an offline task managed by the EESC function using spreadsheets, similar to CAISO's WEIM GRDT and IRDT processes. The CRN output from the transmission registration process would become input data/base configuration data for the Resource Optimization software.

Some specific callouts that will likely require additional functionality in NVE Merchant software include:

- **Bucket 2, Path 1 (Type 1 TSRs) and EDAM External Intertie System Resource/TID Self-schedules:** NVE Merchant will likely need to establish new functionalities in its PRSC bidding software that allow it to submit self-schedules using CRNs to SIBR, as well as submission of System Resource/TID self-schedules in SIBR.
- **Bucket 2, Path 2 (Type 2 TSRs):** NVE Merchant will likely need to establish new functionalities in its PRSC bidding software to submit CRN capacity releases into SIBR.
- **Bucket 2, Path 3 (Type 1 TSRs):** NVE Merchant will likely need new functionality in its PRSC Bidding software to determine remaining CRN capacities available for scheduling after DA.
- **CRN Management:** NVE Merchant may need new functionalities in its PRSC software to manage its CRNs and remaining capacities. These functionalities would be similar to existing functionalities for OASIS transmission service portfolio management.

EDAM Entity Software Impacts

NVE will have to work with the WEIM EESC scheduling-system vendors (OATI) so that they can create a new, or extend existing WEIM EESC packages, to include the new transmission contribution, import/export and scheduling functionalities. At the time of this Gap Assessment, OATI is offering a new webEDAM scheduling system to support EDAM EESC function. In this software development process, NVE must ensure that any customizations to reflect its BAA characteristics are correctly reflected in the vendor design. The following functionalities will be required in EDAM Entity Software:

- **EDAM Transmission Registration Process:**
  - Support the registration of firm Transmission paths with the CAISO, including the association of CAISO CRNs with those paths.
- **EESC CRN Management Process:**

  - Support the ongoing updating of CRN management, ensuring OASIS TSRs/NITS Scheduling rights capacity is aligned with any established CRNs
- **Pre-Day Ahead Market Close:**
  - For Transmission Customers who are not CAISO SCs, submission of Bucket 1 (TSR Type 1) self-schedules with CRNs, System Resource/TID self-schedules, Bucket 2 Path 2 (TSR Type 2) transmission contributions
  - Submission of Type 3 TSRs
  - Evaluate and calculate available firm transmission, submission of capacity for Bucket 3 (Type 4 TSRs)
- **Post-Day Ahead Market Run:**
  - Retrieve Day Ahead and RSE transmission obligations
  - Continuous submission of TSR and CRN limits
  - Make remaining unobligated transmission re-available to OASIS related to Bucket 3 (Type 4 TSRs)
  - Retrieve of market awards for EDAM Transfers, submission of e-Tags for any Type 3 or Bucket 3 (Type 4) Awards
  - Review of any untagged transmission customer awards, communication and notification to customers of any untagged awards
  - Submission of Real-Time Bids for any transmission customers who are not SCs
  - Submission of RTSI schedules (similar to existing WEIM process)
- **Transmission Customer Portal Capabilities:**
  - NVE may need to stand up a Customer Portal which will allow transmission customers ability to submit various transmission self-schedules and transmission contributions to EESC, and EESC makes submissions on behalf of those customers to CAISO SIBR

4.3.4 Software Interfaces

EDAM software interfaces will fall into one of three categories: appropriation of an existing MRTU Day Ahead interface; extension of an existing CAISO interface or reporting application; or an entirely new CAISO application or interface. An overview of potential software interface changes is described below:

- **Appropriation of existing CAISO interface/application:** At this time, there are no CAISO applications/interfaces that can be used as-is for EDAM without changes.
- **Extension of an existing CAISO interface/application.**
  - **SIBR**: SIBR application will be used predominantly for all transmission contributions, self-schedules of TSRs and System Resources/TIDs, and release of CRN capacity. SIBR is being significantly augmented to handle these new interactions.
  - **MasterFile**: The CAISO's existing Master File will be leveraged and augmented to use a new Transfer Data Template (TDT), which the EESC will use to register multiple types of CAISO data types related to transmission, including, but not

limited to, CRN registration, TSR definition, Transfer Locations, Intertie Constraints (ITC), and other System Resources.

- **CAISO OASIS and CMRI**: These applications will be extended to include EDAM data and market results:
  - Retrieval of RSE results (interim and final binding)
  - Retrieval of different types of Bucket (TSR) awards
  - Communication of RSE obligated transmission capacity.

5. TRANSMISSION OATT AND COUNTERPARTY TRANSMISSION SERVICE CONTRACTS

Given the differences in transmission treatment in EDAM, some substantial changes to NVE's OATT will be necessary. These changes will track the functional areas as necessary, but many of the changes will concern transmission contribution and cost allocation. A significant discussion on transmission contribution can be found in the previous section of this report.

5.1 Current State

NVE updated its tariff when joining the WEIM and went through a significant stakeholder and FERC filing process. As the second WEIM Entities, NVE was able to build on the tariff changes that PacifiCorp had made, and successfully received approval from FERC.

5.2 EDAM State

It is anticipated that, like with WEIM, entities that join the EDAM market initially will be the groundbreakers in drafting new tariff language that will help pave the way for later joining entities. With PacifiCorp and Portland General Electric as the initial market entrants, NVE would likely be able to leverage aspects of their tariff language and potentially those of entities that follow with implementations in 2027, LADWP and BANC, although those entities are not FERC-jurisdictional.

The treatment and implications of transmission contributions will be the major areas where changes must be made. A few of the areas of particular note that may require some time investment to address are:

- Allocation methodology for transfer revenue, congestion revenue, and redispatch costs
- Method to register transmission service (covered in "Transmission Service and Modeling" section)
- RSE-related changes (timing and how the information would be submitted to NVE)
- If there are any requirements that transmission customers become or hire SC services
- Settlements and related pass-through in retail rates

In the run-up to NVE's WEIM entrance, NVE engaged in approximately 1.5 years of public tariff and stakeholder processes to support PUCN processes, tariff revision review sessions, tariff filings, business practice changes, and customer changes. For NVE's EDAM entrance, it would be expected that NVE plans for a similar level of public processes to support the Public Utility Commission of Nevada (PUCN), tariff revision and filing, and associated workshops to discuss business practice, customer impacts, and trainings. NVE identifies that it would plan for an OATT filing with FERC to occur approximately 1.5 years ahead of a planned entrance to EDAM.

No changes to existing transmission service contracts are anticipated due to EDAM participation. Most contracts are compliant with existing WEIM rules, and the EDAM-related changes that need to occur will be made under OATT. NVE has identified that it has some legacy transmission rights associated with Valmy and Nellis Air Force Base. These transmission rights may need special treatment as they relate to CRN registration and management, which is described further in the "*Transmission Service and Modeling*" section of this report.

5.3 Gaps

NVE should work with CAISO to refine the mechanics of how transmission will function operationally under the EDAM paradigm. Significant discussion is provided on this in the "Transmission Service and Modeling" section; however, it is expected that some aspects of the transmission service model and downstream tariff and contract impacts will continue to be refined and reworked as the first entities join EDAM. At the minimum, implementation project related tasks will consist of retaining outside counsel, drafting new tariff language, executing the stakeholder process, and filing the revised tariff with FERC. Associated with tariff process, NVE should expect to adopt a new EDAM Markets Business Practice, or modify and augment its WEIM BPM to include EDAM business practices.

5.3.1 Staffing

Outside counsel will be retained to support OATT changes and the FERC filing. No other additional staffing will be needed for this portion of the project. It is not anticipated that additional legal resources will be required to support post go-live implementation.

5.3.2 Business Process

No new business process should be required, but additional clarity on NVE's posted business practices will need to be provided. NVE should expect to develop a new EDAM Markets Business Practice or modify and augment its WEIM BPM to support both EDAM and WEIM.

5.3.3 Software Applications

Software changes related to transmission and RSE will be relevant to effectuating the OATT changes, but no additional software specific to OATT should be needed, and no additional software changes will be required to support OATT changes. Note that several software changes are expected to support the overall Transmission Model, which are covered in the previous section.

5.3.4 Software Interfaces

As detailed in the previous section, interfaces may relate to the Transmission Service and Modeling, but none are required specifically to the OATT-related work.

6. THIRD PARTY LOAD AND GENERATION

6.1 Current State

NVE has at least 26 third-party LSEs in NVE's BAA. Several LSEs have smaller solar generation, and two LSEs have larger generation facilities, with several new third-party generation resources coming online over the next few years. Generally, these LSEs only supply generation for their load, and any remaining energy is exported off-system.

NVE requires all LSEs to have a scheduling agent. The scheduling agents are required to provide a load forecast for each LSE on the preschedule day. Excel spreadsheet load forecasts are emailed from the LSE SCs to NVE for pre-scheduling. Generally, these spreadsheets provide a forecast of the e-Tagged volumes that LSEs plan to serve their load, which NVE treats as a proxy for the LSE load forecast.

Based on data obtained during the Gap Assessment, as well as publicly available NITS Customer data from NVE OASIS, a table is provided below detailing each of all confirmed NITS Customer LSEs (other than NVE Merchant), On-system Designated Network Resources (DNRs) for the NITS customer (DNRs both confirmed and in pending state), as well as Other DNRs (e.g. off-system imports), and the current agent for the NITS Customer.

Table 5 – NVE NITS Customer Data

NITS Customer	On System Network Resources	Other DNR	Current NITS Agent
Air Liquide	None	Off-system imports	Tenaska
Nevada Gold Mine (Barrick)	Western 102 Gas Reciprocating Plant	Off-system imports	Tenaska
BPA Wells	None	Off-system imports	BPA
BPA Harney	None	Off-system imports	BPA
Caesars	Tamarack Solar 60MW, Small Solar	Off-system imports	Tenaska
Caesars North	None	Off-system imports	Tenaska
Circus Circus	None	Off-system imports	Tenaska
City of Fallon	Patua Geothermal / Solar 12MW	Off-system imports	UAMPS
Core North	Citadel Solar, Crescent Dunes	Off-system imports	Tenaska
Core South	NCA Solar	Off-system imports	Tenaska
CRC - SNWA	Small Solar	Off-system imports	WAPA DSWM
Georgia Pacific Gypsum	None	Off-system imports	Tenaska

NITS Customer	On System Network Resources	Other DNR	Current NITS Agent
Hard Rock Las Vegas	None	Off-system imports	Tenaska
Liberty Utilities CalPeco	Luning Solar, Turquoise Solar	Off-system imports	Unknown
LMUD (future, but likely before EDAM)	Fish Lake	Off-system imports	Unknown
MGM	Tamarack Solar, Aria Cogen, Playa Solar	Off-system imports	Tenaska
Mt Wheeler	None	Off-system imports	Deseret Power / Morgan Stanley
Nevada Gold Mine (Newmont)	TS Power	Off-system imports	Tenaska
Overton Power District/Lincoln Co Power District	Escape Solar (future)	Off-system imports	Tenaska
Peppermill	None	Off-system imports	Tenaska
Plumas Sierra Cooperative	None	Off-system imports	NCPA
Reno City Center	None	Off-system imports	Tenaska
Rio Las Vegas	None	Off-system imports	Tenaska
Sahara Las Vegas	None	Off-system imports	Tenaska
Truckee Donner PUD	Small Hydro	Off-system imports	UAMPS
Wynn	Wynn Solar, Tamarack Solar	Off-system imports	Constellation

As shown in the table, many LSEs currently use Tenaska as their NITS agent. For NITS resources, nearly all NITS customers rely on off-system imports to serve their load, however a number of the NITS customers also have ownership and/or PPA arrangements for on-system resources (third party generation), either online or planned to be energized in the following years. A table simplifying the observed third-party NITS on-system resources is provided below, limiting resources shown to those resources over 3 MW (NVE's current threshold for which resources are represented in its WEIM network model) and that can be represented as a non-participating resource or participating resource in the WEIM today.

Table 6 – NVE Simplified NITS Customer Data

NITS Customer	On System Network Resources (Third Party Generation)	Current NITS Agent
Nevada Gold Mine (Barrick)	Western 102 Gas Reciprocating Plant	Tenaska
Caesars	Tamarack Solar	Tenaska
City of Fallon	Patua Geothermal / Solar 12MW	UAMPS
Core North	Citadel Solar, Crescent Dunes Solar	Tenaska
Core South	NCA Solar	Tenaska
Liberty Utilities CalPeco	Luning Solar, Turquoise Solar	Unknown
LMUD	Fish Lake	Unknown
MGM	Tamarack Solar, Aria Cogen, Harry Allen Solar	Tenaska
Nevada Gold Mine (Newmont)	TS Power Solar	Tenaska
Wynn	Wynn Solar, Tamarack Solar	Constellation

6.2 EDAM State

6.2.1 Third Party Load Serving Entities (LSEs)

In EDAM, new processes and considerations for LSEs will need to be developed for both NVE retail load (NVE Resource Optimization) and other third-party LSEs within the NVE BAA. NVE will need to determine LSEs' options for selecting a CAISO Scheduling Coordinator who most likely would be the current NITS scheduling agent (LSE SC), determination of load forecasts for LSEs, transmission service, bidding options for LSE SCs, RSE suballocation, and meter data provisions. These represent many new processes for an EDAM Entity and LSE Entity that were not present in WEIM.

A summary of the significant components for LSE participation is provided below. While many of these components apply to NVE's retail/native load, the emphasis is third party LSEs below, as special considerations will need to be made for these LSEs during an EDAM implementation project.

This implementation portion will be time-intensive and create work for LSE Entities that they do not have to perform today. Stakeholder processes will be a critical part of a successful implementation.

LSE SC Options

- In EDAM, the EDAM Entity will need to determine LSEs' options for selecting its Load Serving Entity Scheduling Coordinator (LSE SC). Generally, options for the LSC SC include the EDAM Entity SC serving as the LSE SC or an independent SC serving the LSE SC.
- To the extent that NVE allows for third-party LSEs to obtain their own LSE SC, NVE will need to communicate with its customers during the implementation of the stakeholder processes and timelines, constraints, and deadlines that CAISO may have if an LSE desires to establish and register a new SC with CAISO. CAISO has specific processes and minimum timelines for an entity to become an SC. This information should be provided during stakeholder processes early in the implementation phase.

Load Forecasts

- The EDAM Entity will need to determine the data source for forecasting third-party loads.
- Currently, NVE receives Excel spreadsheet load forecasts across the preschedule day from the scheduling agents of its LSEs to indicate their load forecasts.
- To the extent that NVE continues to use the external load forecasts from its third-party customers as an input to market processes, NVE may need to develop and enforce new timeline requirements for receipt of this data. At present, the load forecasts do not appear to be delivered to NVE in a timeline that would meet the requirements to serve as a load forecast input for a day ahead of the EDAM market run.
- Further, if NVE continues to use external load forecasts for LSEs that have chosen the EESC SC as its LSE SC, NVE may want to develop functionality for the LSE to provide its load forecast into a Customer Portal, for NVE EDAM EESC to submit to CAISO ALFs and SIBR processes as applicable.

Day Ahead Bidding

- NVE will need to determine third-party LSE SCs' options for bidding their load in EDAM. At a minimum, third-party LSE SCs shall be able to self-schedule and bid their load into EDAM.
- Economic load bidding may also be an option for third-party LSEs. NVE will need to determine any requirements that must be met for a third-party LSE to bid its load in EDAM economically. Portland General Electric and PacifiCorp have both instituted requirements that economic bidding is only allowed for LSEs that have obtained their own independent LSE SC and only offer self-schedule bids for those LSEs that the EDAM Entity represents. Further, Portland General Electric has recently proposed in its EDAM Tariff Filing that only LSEs who are also EDAM resources, i.e. who have on-system resources / DNRs, could serve as its own LSE SC, and economically bid its load.

Transmission Rights

- Transmission rights and scheduling requirements are discussed in detail in the "Transmission Service and Modeling" section, however, NVE EESC should expect to work with all third-party LSEs to assign CRNs for any transmission rights that customers have, particularly firm and conditional firm, and network transmission rights.
- The majority of NVE third-party LSEs are NITS customers. NVE EESC will need to establish CRNs for network rights for these NITS customers, associated with both on-system and off-system DNRs. Third-party LSEs will use these CRNs when self-scheduling their on-system and off-system resources to ensure they receive appropriate market scheduling priority to serve their load.

Meter Data

- LSEs must ensure their LSE SC has access to the meter data needed to satisfy SQMD data submissions to CAISO. If the LSE has chosen its own LSE SC (not the EDAM EESC), it will need to ensure the LSE SC has access to its meter data to submit that data to CAISO (e.g. MRI-S). The EDAM Entity may require that the LSE grant access to the EDAM Entity to the LSE's submissions made into MRI-S.
- To the extent that the LSE has chosen or is permitted to use the EDAM EESC as its SC, the LSE will need to ensure that the EDAM EESC has the means to obtain that data.
  If the EDAM Entity owns the meters for the LSE and already has access to those meters, provisioning of the LSE's meter data to the EDAM Entity for market meter data submissions may not require any additional processes or technology. Alternatively, if the EDAM Entity does not have access to LSE metering data, the EDAM Entity may need to develop processes and technology for the LSE SC to provide that meter data to the EDAM Entity.

RSE Allocation

- LSEs are subject to day ahead RSE obligations. The EDAM Entity will need to determine which components of the RSE LSEs will be responsible for meeting.
- It is expected that, at a minimum, the EDAM Entity will require that third-party LSEs ensure that they meet their portion of a calculated portion of the EDAM Area Demand (Load) Forecast obligation; however, the EDAM Entity may also need to decide whether third-party LSEs are also responsible for their portion of the imbalance reserve requirement.
- Meeting the RSE demand requirement will require that third-party LSEs ensure their day ahead economic bids for self-schedule TSR Type 1 imports, System Resource, and TID imports are submitted into SIBR before the financially binding RSE run. To the extent that third-party LSEs have on-system generation supply, third-party LSEs will need to ensure self-schedule and/or economic bids for those generation resources are also submitted.

- CAISO will run multiple EDAM RSE evaluations in the day ahead, with evaluations performed every 30 minutes starting at 6:30 am and ending at 9:30 am, and the final binding RSE at 10:00 am.
- EDAM Entities will need to ensure their third-party LSEs receive the result of the advisory RSE evaluations as soon as they are published, as well as provide the third-party LSEs with results on whether their supply meets their Demand RSE obligation and, to the extent applicable, whether that third-party LSE has met their IR RSE obligation.
- If LSEs fail to meet their RSE requirements, the EDAM Entity will need to determine how any applicable RSE penalties may be suballocated to third-party LSEs. NVE may consider earlier EDAM Entities' approaches, e.g., PacifiCorp and Portland General Electric, to determine an approach for RSE penalty suballocation.

6.2.2 Third Party Generation

Third Party generation and NVE-owned or contracted generation will need to undergo several processes and meet specific requirements to qualify as an EDAM resource and participate in EDAM. The EDAM Entity will need to develop and implement processes and requirements to ensure the EDAM resource has chosen a Generation Scheduling Coordinator (Generator SC), is registered properly in the EDAM Entity CAISO FNM, satisfies operational characteristics (i.e. if the EDAM Resource is to be bid economically), obtains transmission services, and submits bids.

Generator SC Options

- Like LSE SC options, the EDAM Entity will need to determine what options EDAM resources, both NVE generation EDAM resources and third party generation EDAM resources, have for selecting a Generator SC. NVE may consider options whereby its EDAM EESC acts as a Generator SC, allows an EDAM resource to obtain its own Generator SC., or requires an EDAM resource to obtain its own Generator SC. Third-party generators are currently responsible for entering their base schedules directly into BSAP.
- To the extent that NVE allows or requires third-party generation resources to obtain their own Generator SC, NVE will need to communicate with its customers during implementation stakeholder processes and timelines, constraints, and deadlines that CAISO may have for a generation resource to establish and register a new SC with CAISO. CAISO has specific processes and minimum timelines for an entity to become an SC. This information should be provided during stakeholder processes early in the implementation phase.

FNM Registration / GRDT

- The EDAM Entity will need to facilitate a process with third-party generators to ensure that the operational characteristics of the resource are properly registered in the CAISO Full Network Model (FNM). This process will be similar to current processes for registering resources through the Generator Resource Data Template (GRDT) process.

- NVE will need to determine which threshold it will use to determine if a resource is represented in its network model. Currently, NVE uses a 3 MW threshold to determine if a resource is represented in its WEIM Network Model. It would make sense to carry forward that standard into EDAM.
- Given the list of third-party on-system network resources provided earlier in this section, it appears that NVE should plan for many third-party EDAM Participating Resources, with an increasing number of them being solar/PV.
- NVE has received a few requests from LSEs who desire to build generation "behind-the-meter." There is currently no defined, consistent process for that type of installation. A policy or best practice should be developed.

Generating Resource Participation

- In EDAM, all resources are classified as Participating Resources, and the concept of Non-Participating Resources is no longer applicable.
- To the extent a resource can follow dispatch signals, i.e., receive and follow DOTs from CAISO ADS, that resource can participate in EDAM and submit both self-schedule and/or economic bids.
- If the resource cannot follow dispatch signals, that resource is only allowed to submit self-schedule bids.
- It is recommended that NVE evaluate its current third party and upcoming third-party generation to determine the extent to which those third-party resources could economically participate in EDAM.

Transmission Services and Rights

- The EDAM Entity will need to determine the transmission service requirements for EDAM resource participation. In the PacifiCorp and Portland General Electric EDAM tariff filings (pending at the time of this report), both entities have indicated that a resource would be required to hold firm, conditional firm, or be a DNR to bid economically into EDAM.
- NVE could follow these same requirements or determine if different requirements would be more suitable for the generation on its system. It would be recommended that NVE analyze the transmission service arrangements of its on-system, third-party generation, and Section 33.23 of the CAISO Tariff requirements to determine any transmission service requirements.
- The EDAM Entity will also need to follow processes to ensure that any third-party resources satisfying transmission service requirements are allocated CRNs for their generator resources. Initially, it would be expected that any third-party generator with confirmed on-system DNR rights, and/or resources with firm or conditional firm service would be eligible to obtain CRNs for use in scheduling.

6.3 Gaps

6.3.1 Staffing

During the EDAM implementation project, NVE will need to allocate sufficient staffing resources from its Entity/TSP side to handle registration and outreach processes. This is to ensure third-party generation and load is properly registered and prepared for EDAM participation responsibilities.

NVE should plan for approximately 0.5 FTE from the EESC function to handle registration and outreach processes. No additional resources are anticipated to manage third-party generation and load tasks after NVE has joined EDAM.

6.3.2 Business Process

NVE should develop the following business processes to handle third-party load and generation in its EDAM operations:

- **LSE SC and Generator SC Options**
  - Determine which Scheduling Coordinator Options are available to LSEs, including third-party LSEs
  - Determine which Scheduling Coordinator Options are available to generators, including third-party Generators
- **Load Forecast Requirements**
  - Determine the process in which an LSE SC provides submits load forecasts and informs the EESC of its Load Forecast, or provides Load Forecasts to the EESC, if the EESC is acting as the LSE SC
- **Day Ahead Load Bidding Options and Requirements**
  - Determine the options and requirements for LSE bidding, including both load self-schedule bidding and load economic bidding options
- **LSE Transmission Service Registration**
  - Determine the process and plan to ensure that each third-party LSE's eligible transmission service, i.e. network, firm point-to-point, conditional firm, is registered and associated with CRNs
- **LSE Metering Processes**
  - Develop the requirements and processes for SQMD plan submission and SQMD meter data submissions, including specific requirements and processes for LSEs who elect to use the EESC as their LSE SC
  - Determine the processes and requirements specifying the provision of non-NVE owned metering data to be provided to NVE, as well as ensure that NVE EESC has access to any meter data submissions by an LSE SC to CAISO
- **LSE RSE Allocation Processes and Penalties**
  - Determine how RSE requirements are suballocated to third-party LSEs, as well as the allocation of any RSE penalties to third-party LSEs

- **GRDT Registration Processes and Resource Participation**
  - Determine how the NVE EESC will ensure all generation in its EDAM area is properly registered in the FNM with a GRDT, including all third-party generation

In the process of working with third-party generation, NVE EESC will need to ensure that third-party generation is aware of what bidding options it has, depending on its resource operational capabilities (and eligible transmission service).

Resources that can respond to dispatch signals and have eligible transmission service would have the option to self-schedule and economic bid. In contrast, resources not meeting these criteria would only be able to self-schedule.

6.3.3 Software Applications and Interfaces

Several software and interface gaps were identified in the previous sections:

- **Load Forecasts**
  - To the extent that NVE uses load forecasts from third-party LSEs, it should develop a platform and interface for those LSEs to submit those load forecasts to NVE in an automated process. A mechanism to facilitate these data submissions could be scoped into the Customer Portal functionality of the EESC system (e.g. webEDAM EESC). These requirements have been assumed to be part of the overall EESC software requirements.
- **LSE RSE Suballocation**
  - NVE will need a means to communicate advisory and binding LSE RSE suballocations to each LSE. A mechanism to facilitate these data submissions could be scoped into the Customer Portal functionality of the EESC system (e.g. webEDAM EESC). These requirements have been assumed to be part of the overall EESC software requirements.
- **Meter Data**
  - NVE and LSE may need interfaces and mechanisms to exchange meter data necessary for market data submissions. These interfaces may only be required to the extent that NVE does not have access to the meter data, e.g. does not own the LSE meters. A mechanism to facilitate the meter data exchange could be scoped into the Customer Portal functionality of the EESC system (e.g. webEDAM EESC). These requirements have been assumed to be part of the overall EESC software requirements.

7. METERING

7.1 Current State

Before joining WEIM, NVE performed necessary meter upgrades and a metering review with CAISO, and it currently meets CAISO's WEIM metering requirements. However, NVE does not have all SQMDs in place for its interties as is required for EDAM and is currently undergoing an inventory process.

NVE has 56 non-participating resources and 38 participating resources. Of the 56 NPRs, 16 resources have SQMDs in place; the remaining 40 require new or updated SQMDs. As per CAISO compliance requirements, if any of these resources plan to participate in EDAM (as discussed in section 3), then NVE must file an SQMD with CAISO.

Along with this, NVE needs to ensure that equipment in the field, such as CTs and PTs, has proper accuracy classes, calculations, and paperwork in place (part of the SQMD process). Utilicast will work with NVE to ensure that all necessary paperwork is in place for these resources to comply with and participate in EDAM. The budget for this work will be shown in the final cost estimate budget workbook.

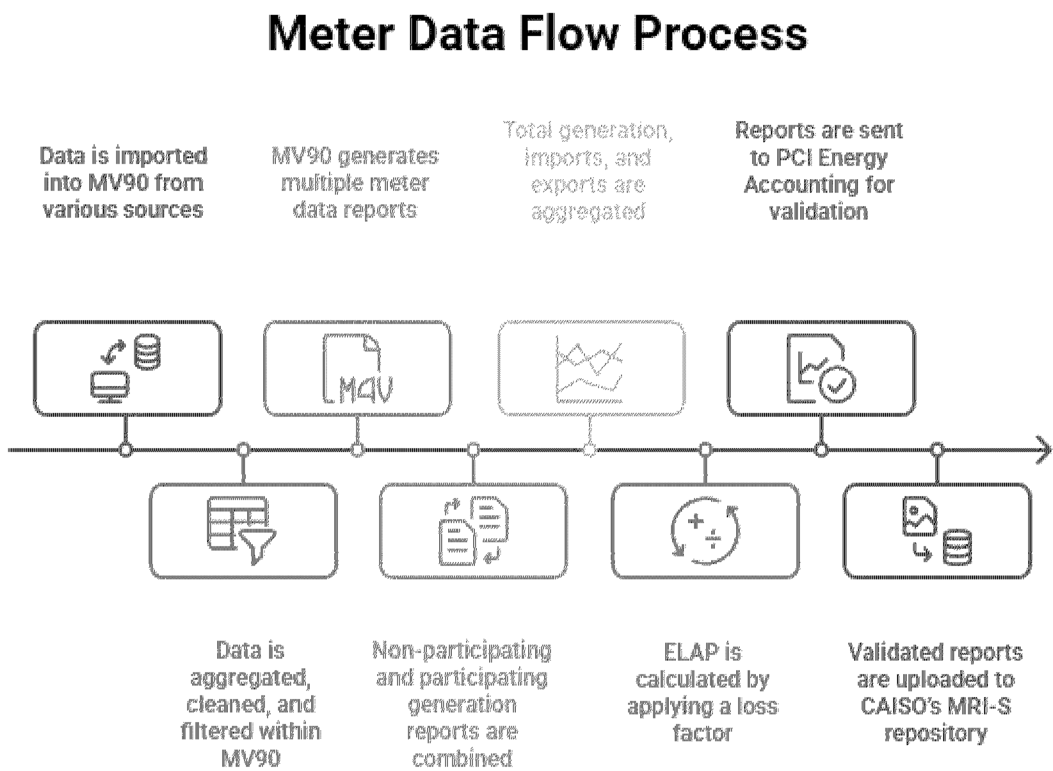
For the current WEIM resources that participate in WEIM, there are a total of 38 resources. Out of these, six have SQMDs. As per NVE's plans for WEIM resources, these will participate in full DA/RT mode. Hence, the remaining 32 resources need proper documentation, including SQMDs, in place for them to be compliant and participate in EDAM.

NVE has well-defined, documented processes, roles, and responsibilities. The metering team performs meter data validation, estimation, and editing (VEE) using their in-house Excel macros and PCI Energy Accounting software. When issues arise, they investigate and troubleshoot with upstream groups and make corrections.

The metering team uses MV90, PCI, and AVEVA PI software for various types of meter data. MV90 is currently used for meter data management. The metering team supports formulation changes required in PCI. NVE has been making regularly scheduled upgrades to the software and receiving adequate support from the vendor as needed.

The metering team uploads all data from MV90 to PCI to MRIS. The data flow is discussed in depth in the section below and illustrated in the following chart.

Figure 4 – NVE Current State Meter Data Flow Process



All meter data is stored in the MV90 system. Data is read every two days from the field into MV90 via an automated process. The metering team coordinates with the field meter operations team for any issues. Field operations will provide flat files to the metering team if necessary, which are manually uploaded into MV90. Two separate electric meter operation teams cover the north and south regions.

Tie lines and four other meters are provided via a daily file from the AVEVA PI system and are manually imported into MV90.

For Hoover, WAPA uploads daily files into the BOX cloud service, and this file is manually downloaded by the NVE metering team and imported into MV90. Once all meter data has been imported into MV90, it is compiled and passed to PCI Energy Accounting.

Meter Data Import Flow:

The following types of data are uploaded to MV90:

- Meter data for Participating and Non-Participating resources.
  - MV90 collects this data from the meters in the field

- For participating resources, the data is 5-minute intervals; for non-participating resources, the data interval is 15 minutes.
- Hoover Dam files from WAPA are provided in a csv format. The data interval is 5 minutes.
  - WAPA uploads these files to BOX.com, a cloud-based file-sharing system, and then manually downloaded by the NVE metering team.
- Load Entities Meter data
  - This data is sourced from the AVEVA PI system as a .lse file. PI jobs are run manually at 8 am daily, and the user manually copies files using Explorer.
  - This data is in 15-minute intervals
- Field-provided meter data
  - Field technicians provide this data in a .hhsf file, sent via email or copied to a shared directory, and manually imported into MV90.
  - These files contain tie line data for imports and exports. The tie line data interval is 5 minutes and is available via AVEVA PI.

MV90 Processing and Calculation

MV90 processes the data and calculates Total Generation Aggregate, Total Load, and Total Imports and Exports. MV90 uses these calculations to generate an External Load Aggregation Points (ELAP) file. The ELAP file represents NVE's system peak by operating day and is used in the settlements process to determine UFE and imbalances. The ELAP is a 15-minute interval datafile. MV90 applies a load calculation loss factor of 0.98423 when calculating ELAP. ELAP is then fed to PCI Energy Accounting software.

Along with the ELAP, meter data for participating resources, non-participating resources, tie line data for imports and exports are also directly fed from MV90 to PCI Energy Accounting software.

PCI Energy Accounting

Once MV90 has interfaced the meter data to PCI Energy Accounting, the PCI software then performs the following functions:

- Upload the meter data to the CAISO MRI-S (Market Results – Settlements) website, transmitted via xml format
- Runs calculations for balancing on behalf of the billing team
- Generates reports for the billing team and other downstream uses

Typically, the metering team executes this process twice a week.

VEE Process

The metering team has an established process for validation, estimation, and editing (VEE). Most of this is done automatically. Validation includes the following tasks:

- Flagging interval data that does not match the corresponding register channel data

- Reviewing interval/event status codes
- Missing and out-of-range checks
- Smoothing out meter data due to operational failures, meter tests, etc.

Estimating involves:

- Copying and pasting meter data from a previous period that is good/valid
- Estimating usage based on register reads, load profiles and statistical methods

Editing includes:

- Correcting obvious read errors, e.g. if a meter reader mistakenly enters a wrong digit
- Adjusting for meter malfunctions (if a correction factor is known)
- Overriding estimations with validated manual reads

Annual Maintenance

The metering team also performs yearly field meter testing on all WEIM metering points. NVE either physically conducts the test or witnesses the test if performed by another entity.

Special Cases

- The Valmy Power Plant is currently undergoing an upgrade and will transition from PI to telemetered data. These two existing units may benefit from adjusting metering to directly meter the net output of each unit; however, a deeper review would be warranted before making a decision.
- Sierra Solar generation interconnection facility is in the process of energization. The metering team is currently onboarding this resource.
- Brunswick is a black start resource and only runs sporadically.

Compliance

Internal compliance groups execute the CAISO self-audit every two years for metering and billing. This is done separately for the north and south areas.

7.2 EDAM State

In EDAM, the same SQMD processes apply as in WEIM, with the two primary distinctions being that embedded LSEs can choose to register and bid or self-schedule their load in the day-ahead market separate from the whole BA load, and there is no distinction in metering requirements for participating and non-participating resources.

During the data-gathering process, Utilicast and NVE identified resources that do not currently have SQMDs. CAISO requires SQMDs to be filed with them for all EDAM participating resources. As mentioned in the RO (NPR to PR) section, for all the resources that NVE chooses to participate in option 1 (Full DA/RT), NVE needs to submit SQMDs. Utilicast will work with NVE to submit these during the project implementation. For those resources where it is difficult to get these details for various reasons, CAISO may grandfather them in.

As per the draft tariff, EDAM's telemetry and metering requirements are nearly identical to those for WEIM entities. An EDAM Entity must either be a CAISO Metered Entity or a Scheduling Coordinator Metered Entity. Scheduling Coordinators for EDAM Resources may elect to submit Meter Data in 5-minute or 15-minute intervals, depending on resource type. Scheduling Coordinators for resources that cannot meter the resource's energy every 15 minutes or faster may not submit economic bids or provide AS and must submit self-schedules in the EDAM and Real Time Market. Current requirements for non-station service metering equipment are:

- Meter:
    - 0.2 Accuracy class
    - 60 days storage for meter data
    - 5-minute interval granularity for Participating Resources and Interchange
    - 5, 15, or 60-minute interval granularity for Non-Participating Resources and Non-Conforming Loads (self-scheduled resources)
- CT:
    - +/- 0.3% accuracy at burden of 0.1 - 1.8 ohms, 10% - 100% rated current
- PT:
    - +/- 0.3% accuracy through burden rating ZZ (400 Volt-Amperes secondary at 0.85 power factor) at 90% through 110% of nominal voltage

CAISO will also perform an EDAM onboarding process to check and validate all meters. NVE will continue to be subject to annual self-audits, just as they are under the WEIM framework. NVE's existing annual metering self-audit plan procedures should still be sufficient.

Metering Standards

Most of the resources currently operating in WEIM meet EDAM requirements. As mentioned above, many resources need SQMDs. Also, new resources added to the market would also require the meter data to be evaluated to ensure they meet the expected criteria.

As detailed in the Resource Optimization section, NVE may consider changing the current WEIM NPRs to participate and bid into the EDAM. These resources would then go through the evaluation and validation process. This is an effort that NVE needs to make before the EDAM implementation project.

7.3 Gaps

7.3.1 Staffing

No changes in metering staffing needs are expected for EDAM participation during the implementation project or for ongoing support. If NVE elects to convert existing NPRs to PRs, there will be a project staffing impact to ensure proper metering. There will also be a staffing impact when developing and submitting the newly identified SQMDs to CAISO.

7.3.2 Business Process

No changes in metering processes are expected for EDAM participation.

7.3.3 Software Applications

No changes in metering software are expected for EDAM participation.

7.3.4 Software Interfaces

No changes in metering interfaces are expected for EDAM participation.

8. SETTLEMENTS AND INVOICING

NVE is already performing WEIM Settlement activities, and the new EDAM settlement charge codes will be added to the existing processes. With EDAM, the bulk of the increase will fall more heavily on EESC settlements rather than PRSC settlements. MRTU settlements will essentially cease as EDAM participants cannot bid at CAISO interties in MRTU; instead, they will shift to resource-specific bidding in EDAM.

CAISO will bill for the recovery of loss transmission revenues based on NVE's historical Wheeling Access Charge (WAC) costs for MRTU exports from CAISO, billed to the EDAM Entity.

8.1 Current State

NVE uses meter and financial transactional data from OATI in Excel workbooks to determine the amounts owed to or receivable from entities participating in the WEIM. These amounts are paid/collected for the T+9B, T+70B, and T+11M settlement periods.

The transmission department performs the NVE WEIM Entity settlements, and the Resource Optimization department performs the Resource Optimization settlement process. Both Transmission and Resource Optimization teams push settlements financial data to accounting, which executes accruals, GL mapping, and company allocations.

PRSC Settlement Process

The Resource Optimization team executes settlement activities using Excel, PCI, and homegrown Oracle-based reports. Like transmission, the Resource Optimization settlements team goes through multiple manual steps.

The PCI settlements module calculates a shadow pre-settlement using real-time prices and dispatch results. This is done after the operating (OD+1) day. This data is then used to understand the impact on cash flow, resource positions, and reduction in revenue due to any operational issues, as well as validate data for completeness.

The majority of the settlement work usually occurs on OD+9. The PCI software downloads the statements each night and performs shadow settlement calculation. PCI settlement workflow is as follows:

- Run CAISO settlement to compute CAISO settlement charges
- Perform shadow settlement calculations using available shadow determinants and independent data sources
- Display CAISO and shadow settlement side by side for easy comparison
- Store settlement results for reporting
- Feed downstream systems by creating a file sent to Fuel and Purchase Power Accounting, which is imported into their stand-alone PCI software.

Resource Optimization analysts use PCI to evaluate the shadow settlement statement, looking for discrepancies and determining whether the issue is disputable or a data quality issue. Based on the type of issue, an analyst may raise a ticket with PCI for system/data/application issues, e.g. improperly mapped charge codes.

The other important aspect of this verification process is to review the CAISO settlement process. This data is shared with other groups, such as RO, to get more insights into the impact of trading strategies or the behavior of new participating units.

In particular, the following energy charge codes are reviewed regularly for anomalies and patterns:

- CC64600 FMM Instructed
- CC64700 RTD Instructed
- CC64750 RT Uninstructed
- CC66200 Bid Cost Recovery
- All energy charge codes by date
- Positions MTD/charge code
- All other charge codes by position/date
- BESS meter data review

PCI P&L analyzer, SettleCore, and daily RO WEIM operations reports are also used during the Settlements verification process.

The Resource Optimization team executes multiple manual steps, including copying and pasting data from PCI to Excel. This is generally time-consuming and error-prone and leads to avoidable delays. There is an opportunity for NVE to automate some of these processes so there is less room for error, and helps make the data readily available for reporting and analytics.

PCI is vendor-hosted and managed. The Resource Optimization settlements team has previously encountered technical issues with the PCI platform that take away time from the actual settlement process. During EDAM discussions, these issues should be surfaced with PCI to ensure support and technological capabilities are improved during EDAM.

EESC Settlement Process

For WEIM, the EESC Team is utilizing the OATI products for all back-office related processes, i.e. meter data management, settlement and invoice download, settlement and invoice validation, loss billing, TC allocations, and invoice allocation to the general ledger of accounts.

NVE EESC uses OATI webSettlement for WEIM processes, webAccounting for meter data management, and Excel and PCI. All WEIM reporting and analytics are supported by the Transmission (EESC) Settlements team, using internally maintained tools like Tableau, Excel, and SQL.

Major steps of the EESC settlement process include:

- Running Daily Files
- Importing the meter data into the WEIM module of webSettlements
- Importing the Schedules into the webSettlements module
- Allocating the data to each customer

A large number of in-house-developed Excel macros are used for customer billing. The OATI data is manually copied and pasted into Excel, and these macros are used to generate customer invoices. After approval, invoices are emailed to customers.

As mentioned above, staff time is needed to support issue resolution with the OATI and PCI software and, to a lesser extent, CIDI Cases. The time NVE staff dedicates to OATI and PCI issues, CIDI case resolution, configuration, and reconfiguration is not available for market analysis. A significant percentage of the settlements staff's time is used to backfill and correct shadow settlement data.

GHG and RPS

The state of Nevada has set ambitious goals to reduce its greenhouse gas (GHG) emissions and increase its Renewable Portfolio Standard (RPS). According to the PUCN, the percentage of renewable energy required by the RPS will increase at a scheduled rate until it reaches 50% in 2030. NVE measures (RPS) as a ratio of Renewable Generation (Sum of Renewable Meters) to Native Load. Nevada also has GHG emission reduction goals for the state as a whole. Both programs record the emissions and the credits at the generators; however, they do not have any language regarding market treatment or energy transfers.

NVE has an existing GHG process that serves Liberty Utilities in California. NVE has set procedures and timelines to calculate and verify the meter data, energy credit transfer, and Western Renewable Energy Generation Information System (WREGIS) certificates. NVE coordinates with Liberty and sends all required data to the California Air Resource Board (CARB). Renewable credits are divided between SPPC (Nevada North) and Liberty by mid-April. The reporting is done via the California Electronic Greenhouse Gas Reporting Tool (Cal e-GGRT) by June 1st of each reporting year. NVE goes through further verification processes in August, September, and November to review invoices, and finally transfers CCAs to NVE's general account in its Compliance Instrument Tracking System Service (CITSS).

North-South Deferred Energy Report

NVE uses the PCI GenManager Settlements Allocation module to allocate trades between Nevada Power (NPC) and Sierra Pacific Power (SPPC) as part of NVE's Joint Dispatch Agreement (JDA) between the two entities. Under this agreement, NVE can optimize short-term power trades between NPC and SPPC.

Some constraints and considerations are put in place, such as each generating company recovering the cost of generation before allocating any sale proceeds. The resultant savings are allocated between the two companies. This process requires updating power trades and calculating cumulative monthly totals, plus any required recalculations. Journal Entries (JE) and supporting documents are printed at the summary level to comply with the JE approval process.

Data Flow

At a high level, PCI imports the following datasets:

- Trades from ETRM systems, including Allegro and Aligne
- Generation and Load Actuals from EMS
- Cost to Serve and PRSC settlements results from PCI
- EESC settlement and Transmission Billing results from OATI

These go through the Journal Entry allocation system module; then the output Journal Entry CSV file and Calculation Results Excel file are generated.

8.2 EDAM State

As discussed above, NVE has a mature WEIM settlement process. With EDAM, the responsibilities will be additive to the existing PRSC and EESC settlements processes.

The responsibilities will be more significant for the EESC than the PRSC, with the volume of settlement charges and codes expected to be much higher than the current state. EDAM settlement effects are divided into the following categories:

- New day ahead EDAM Charges
- Existing WEIM charges which will be changed for EDAM
- New EDAM transmission contribution revenue charges and allocations
- New EDAM congestion and transfer revenue charges
- Other EDAM Settlement considerations

New Day Ahead EDAM Charges

The settlement details of EDAM, i.e., Charge Code Configuration Guides, have not been finalized but will be drafted through implementation. Some of the more impactful new charges are detailed below.

- **Day Ahead Energy**
  - Existing MRTU CC 6011: Day Ahead Energy, Congestion, Loss Settlement.
  - Day Ahead award schedules for Generator, Load, and Interchange Resources will be settled in full. This would include full settlement of self-scheduled Resources.
  - This is a substantial departure from the WEIM “imbalance only” paradigm.
- **Day Ahead Bid Cost Recovery**

  - CC 6630/6636/6637
  - These CAISO charge codes leave the CAISO revenue neutral within their charge types.
  - The first makes payments to Resources when an EDAM supplier does not fully recover its Day Ahead bid costs.
  - The second offsets that same Resource payment amount with a charge/uplift to parties deemed to cause the shortfall.
  - The final proposal suggests two options for cost uplift allocation: either allocation to the EDAM Entity according to its OATT, or a CAISO two-tiered allocation method similar to the existing IFM Bid Cost Recovery Tier 1 and Tier 2 Allocations (charge codes 6636 and 6637).
- **Day Ahead Residual Unit Commitment**
  - The final proposal indicates that EDAM participants' resources will fully participate in the existing DA RUC process. Therefore, the DA RUC charge codes are expected to apply in EDAM, CC: 6800: DA RUC Settlement, and CC 6824: No Pay RUC Settlement.
  - The final proposal offers that one of two possible alternatives could be used for the cost uplift: Allocation to EDAM Entity for allocation per the Entity's OATT; or via the CAISO two-tiered allocation, similar to existing CC 6806: DA RUC Tier 1 Allocation, CC 6807: DA RUC Tier 2 Allocation.
- **EDAM/WEIM Transfer Revenue**
  - Settlement of revenue collected due to binding ETSR constraints will become more straightforward rather than being mixed with other congestion concepts.
  - The CAISO will calculate the Marginal Energy Cost of each BAA when the net ETSR limit is binding and determine the Transfer Revenue as the product of the transfer MW and the price separation.
  - The distribution of the Transfer Revenue will then enforce the Bucket mechanism while also accounting for any other special commercial arrangements.
- **EDAM Congestion Revenue Day-Ahead Congestion Offset:**
  - Specific to EDAM BAAs, this charge code applies a congestion offset mechanism. The CAISO BAA's congestion revenue is sub-allocated through CRRs, ensuring that congestion costs are appropriately distributed among entities based on their transmission rights and usage.

  RUC Reliability Capacity Transfer Revenue Settlement:
  - This charge code pertains to the settlement of revenues associated with Reliability Unit Commitment (RUC) capacity transfers. It ensures that the financial aspects of capacity transfers, which can impact congestion, are accurately settled among relevant parties.
- **RSE: IFM and RTM Resource Sufficiency Evaluation Settlement and WEIM RSE Failure Surcharge**
  - With the new RSE pooling framework and the associated administrative charge for directional failures (magnitude and hours) and the failure penalty tiers, these costs will show up with new charge codes.

- **Transmission Recovery Settlement**
  - In exchange for releasing the Bucket 3 transmission to the market hurdle-free, the ISO is providing EDAM BAAs a mechanism to recover gross "at risk" EDAM recoverable transmission revenue, transmission revenue associated with certain transmission new-builds, and excess wheeling revenue.
  - The collected BAA revenue recovery amount will be paid to the EDAM entity.
- **Imbalance Reserve Settlement and Reliability Capacity Settlement**
  - Resources that receive an imbalance reserve upward (IRU) capacity award or an imbalance reserve downward (IRD) capacity award will be paid the applicable nodal price.
  - Entities will also be able to submit bids for reliability up and down capacity and will be settled on the associated marginal prices for each.
- **Flexible Ramp Settlement**
  - The forecasted movement changes in the FMM for Flex Ramp become a delta calculation from day ahead Imbalance Reserve MWs.
  - RTM Flexible Ramp Forecasted Movement settlement will be an imbalance settlement from DA accounting for day ahead schedule Forecasted Movement.
  - Resources receiving an FMM FRU/FRD award will receive an imbalance settlement on the Flex Ramp Uncertainty.
- **RT and IFM Ancillary Service Settlement**
  - EDAM BAAs will self-provide their AS requirements at the start of EDAM.
  - After the CAISO implements functionality to accept bids for AS from resources in EDAM BAAs, scheduling coordinators for resources that receive a day-ahead AS award will be paid the relevant day-ahead AS marginal price.
- **Convergence Bidding**
  - EDAM Convergence Bidding will not be available at the start of EDAM but may be added after the first year.
  - When added, these existing Convergence Bidding charge codes are probable additions to EDAM:
    - MRTU CC 6013: Convergence Bidding DA Energy Congestion and Loss Settlement
    - CC 6473: Convergence Bidding Real Time Energy Congestion and Loss Settlement
  - NVE is not anticipated to participate in convergence bidding at this time.

WEIM Charge Impacts

In addition to new charges, offsets, and allocations, some existing WEIM charges will be impacted by EDAM. The inclusion of a Day-Ahead market component changes WEIM Real-Time Imbalance calculations and inputs in many cases.

The primary impact will be the lack of "WEIM Base Schedules." Instead, the Day-Ahead Award schedule will be the basis for WEIM Imbalance calculations. Since not all current WEIM participants will join the EDAM market at its onset, the CAISO WEIM calculations will be forced to incorporate both the Day Ahead Market Award and the WEIM Base Schedule concepts into the existing WEIM charge codes, such as Energy Imbalance settlement. While not overly significant from an outcomes point of view, it will result in updates to the CAISO's WEIM settlement charge formulas and therefore the WEIM settlement vendor software code. Where EDAM updates existing WEIM charges, NVE will need to review the impacts to determine if the change requires an adjustment to EESC settlement reporting and analysis tools.

The day ahead award schedule will replace the WEIM Base Schedules and will lead to WEIM Imbalance calculations. Since there is no concept of non-participating resources, NVE should pay close attention to the allocation and modification of existing WEIM charges. NVE also needs to review the impacts to determine if the change requires an adjustment to EESC settlement allocation calculations, reporting and analysis tools.

The following section discusses some of the most significant new charges associated with EDAM:

- **FMM and RTD Instructed and Uninstructed Imbalance Energy Charges**
    - The FMM and RT Generator, Load, and Interchange Imbalance settlement will be measured to the EDAM Day Ahead Award (and/or RUC award) quantities.
    - The notion of a Base Schedule goes away for EDAM BAAs.
- **Over/Under Scheduling Penalty Charges CC 6045/6046**
    - EDAM BAs will be excluded from the over and under Scheduling WEIM Settlements.
    - The EDAM Entities will no longer be balancing WEIM Base Schedules.
    - Instead, they will have a 'must offer' requirement that flows from the Day Ahead market, RUC market clearing, and EDAM RSE, ensuring each EDAM entity is adequately resourced in real time.
    - Therefore, these WEIM over/under Scheduling charges will not apply.
- **EDAM Green House Gas (GHG) Settlement**
    - GHG credits currently calculated using only real-time Imbalance MWs must include day ahead and RUC award MWs. A larger GHG settlement is expected since the full energy schedules are added to the GHG consideration.
- **Energy Offset**
    - With EDAM, the mechanism for transferring money between BAAs due to an EDAM/WEIM transfer, previously known as the "Financial Value" embedded in the Energy Offset, will be split out.
    - How the marginal energy cost is considered will also be updated to have BAA characteristics rather than being at the system level.
- **Congestion Offset**
    - EDAM separates the mechanism for assessing Transfer Revenues and Congestion Revenues.
    - Transfer Revenues will be created when Transfer System Resources (ETSR) are constrained, while congestion will be created when other types of physical or scheduling limits are binding.

  - In addition, the effect of EDAM legacy (transmission) contracts and EDAM transmission ownership rights will be included in the offset.
  - This will impact the way the congestion offset functions.
- **Bid Cost Recovery**
  - Bid cost recovery calculations will include day-ahead amounts, including GHG bid costs.

In addition to the new and modified charge codes created by the CAISO, NVE may want to consider changing the logic for allocations of certain charges settled to the EDAM Entity.

New EDAM Transmission Contribution Revenue Charges and Allocations

Significant new EDAM functionality relates to transmission rights and revenue management within the day ahead timeframe. The settlement implications of these changes may be the most important new impact on settlement processes and could require new work. It will definitely require testing and training.

In EDAM, the CAISO will return transmission revenues to the EDAM Entity, and the Entity will be obligated to allocate the revenues equitably to the transmission holders who contributed the rights. This complex process will require the collection of new eTag or OASIS ownership data elements in the settlement process. NVE will need to develop new processes to support collecting and validating new eTag or OASIS ownership data elements in the Settlement process.

The following items require specific attention:

- Of the four types of Transfers in EDAM, only Type 1 will settle directly with SCs.
  - The revenue for Types 2, 3 & 4 will be settled with the EDAM Entity.
- Bucket 2, Path 3 (P3):
  - The ability to determine after-the-fact (ATF) which tags qualify for P1/P3 settlement treatment rather than P2, which will be allocated directly by CAISO.
  - This will require allocation work in OATI with scenarios and detailed requirements.
- Under recovery uplift charges for PTP:
  - Calculated via the average historical transmission revenues for non-firm and short-term firm PTP for the most recent three years, compared to the actual sales revenue.
  - Needs to be provided to CAISO for settlement with a "Revenue Recovery Bond."
    - Will require working with Finance
- Validate charges that NVE is receiving from other EDAM BAAs.
  - There will need to be some billing determinants that show up in the charge codes, but the main mechanism will be CAISO validation of the input data.
  - The attestation of the company executives will determine the reasonableness of the transmission revenue.

Credit Considerations

- CAISO will remain the counterparty to NVE for all EDAM transactions
  - NVE currently has a $25M unsecured credit limit with CAISO.
  - If all NVE were buying all load, this credit limit would last approximately 25 days, which may not be sufficient
  - EDAM participation may lead to an increase in NVE's credit/collateral requirements with CAISO
  - This credit limit needs to be evaluated to determine if additional credit needs to be approved and additional collateral needs to be posted. This will be done as part of the project implementation.

Other EDAM Settlement considerations

- EDAM Admin fees:
  - EDAM participants must pay CAISO a fee for EDAM Market Services and System Operations.
  - This will be implemented as an additional component of the existing GMC CC 4564.
  - The GMC per MW rate for current Day Ahead Market activities is approximately double the WEIM GMC rate.
  - This higher EDAM GMC rate will be multiplied by a significantly larger DA MW base, and EDAM GMC charges will increase significantly.
- Increase in settlement dollar magnitude and credit requirements:
  - Due to participating in the Day Ahead Market, EDAM participants will have significantly more dollars invested and exposed.
  - While the WEIM market focuses only on the real time imbalance MWs, the Day Ahead Market requires full accounting for the base energy. This will apply to load, interchange, and generator resources. Thus, EDAM participants should expect to see the magnitude of their EDAM + WEIM settlements increase significantly.

8.3 Gaps

8.3.1 Staffing

The EDAM Settlement impacts discussed will increase work primarily in validation and reporting. The work for validation will include tasks such as:

- EDAM settlement statement validation,
- EDAM shadow settlements
- Processing and validating charges received from WEIM, EDAM, or other Market entities
- CAISO dispute management

Reporting analytics will include developing and supporting existing WEIM and new EDAM reports.

Existing staff are expected to be able to absorb this additional workload, but an additional 1 FTE is recommended to create a **Settlements Lead** position. If allowed, this FTE may be shared by both EESC and PRSC groups. However, most of the extra work will be done by EESC; hence, this FTE should be in that group if resource sharing is not allowed.

The significant areas this additional FTE will spend on are validation and sub-allocation. The work for validation will include tasks such as EDAM settlement statement validation, EDAM shadow settlements, processing / validating charges received from other WEIM, EDAM, or other Market entities, and CAISO dispute management. Sub-allocation work will include EDAM sub-allocation data validation, EDAM charge codes suballocation, billing Transmission Customers, TSR Billing Functions, and Transmission Customer dispute management.

Also, as per discussions with the PRSC group, staffing is adequate currently, however, the group will be stretched with EDAM. This needs to be evaluated further during the project implementation.

EDAM will only increase the dependency on manual work, e.g. assembling files, copying and pasting data, running macros, etc. These tasks must be documented and automated to ensure the additional EDAM workload does not overwhelm the current staff.

Combining PRSC and EESC Settlement Teams

During the gap analysis, it was noted that there is minimal technological overlap between the two settlement teams, and each team uses a different software package, PCI Settlements for PRSC and OATI webSettlements for EESC. There are potential advantages and disadvantages to combining these teams and toolsets, as described below:

- **Potential for Efficiency**
  - Combining teams could lead to a more streamlined workflow, reduced duplication of effort, and better communication between those handling resource-level and BAA-level settlements.
- **Holistic Understanding**
  - A combined team might develop a more comprehensive understanding of the entire EDAM settlement process, from individual resource behavior to the overall BAA financial outcomes.
- **Shared Skill Sets**
  - There can be overlapping skill sets required for both roles, such as understanding CAISO market rules, settlement statements, and data analysis.
- **Application Consolidation**
  - The settlement processes can be consolidated onto a single platform, reducing licensing and training costs and enforcing account Role-Based Access Control

Combining these teams also has disadvantages, including the potential for overwhelming them, different focuses and granularities, and varying institutional knowledge. System and application permissions can be configured to ensure staff adhere to FERC standards of conduct.

Combining the settlement teams and applications should be investigated as part of the EDAM implementation.

8.3.2 Business Process

The following business processes will need to be updated:

- **CAISO Settlement Statement Validation**
  - At a high level, settlement processes will not change dramatically in the EDAM paradigm. CAISO will continue to publish daily and monthly settlement statements on the current T+9, T+70, etc. timeline, including the new EDAM-related charges.
  - The CAISO will continue to invoice on the current weekly timeline. With EDAM, there will be more CAISO-related settlement charges and inputs to review and evaluate, but the overall process will remain essentially unchanged.
  - The settlement statements should continue to be processed similarly to the current WEIM approach, with the new EDAM charges incorporated into the existing WEIM process.
- **Non-Participating Resources**
  - In EDAM, there is no concept of a non-participating Resource or load.
  - All NVE's generation and load become participating in Resource Optimization's activity.
- **EESC Allocation**
  - EESC Allocation approaches will need to be developed for each new EDAM charge code. Existing WEIM charge code allocations should also be reviewed to ensure the existing approach continues to produce desired outcomes in the EDAM paradigm.
- **EDAM Transmission Transfer Revenue Allocations**
  - This new concept requires additional processing when considering how best to allocate the proceeds.
- **CAISO Settlement Invoice Processing**
  - The addition of EDAM does not appear to impact the PRSC or EESC invoice validation or payment process, however the existing invoice process would need to include updated charge codes for EDAM.
- **WEIM Entity Allocation Invoice Processing**
  - The addition of EDAM does not appear to impact the WEIM Entity Allocation monthly invoice process. The existing invoice process would include new EDAM and updated WEIM charge codes. While the task remains similar, there are anticipated to be updates:
    - The volume of settled transactions is projected to increase.
    - Since almost all transmission customers will receive sub-allocations monthly, there will be a much higher volume of transactions and a much higher dollar

value for transactions. Validating this higher volume to ensure a high-quality suballocation and billing will be time-consuming. If there are inquiries or errors, it is likely that the effort required to resolve them will also increase.
    - The current processing of WEIM sub-allocations and invoices takes about 4 hours a week to perform basic validations and ensure a high-quality invoice. This effort is anticipated to increase significantly because of the volume of transactions settled in EDAM.

- **Settlement Staff Training**
  - Existing settlement staff will need to learn the updated EDAM-related charge codes.
- **CAISO Dispute Resolution Processes**
  - The volume of CAISO settlement disputes may rise temporarily after the EDAM launch. Both the CAISO and EDAM participants face a large number of new and updated settlement calculations.
  - This will likely result in more calculation errors than the current WEIM participants are accustomed to. NVE may want to consider how this temporary, additional workload could be managed.
- **North-South Energy Reporting, aka Deferred Energy Report**
  - This process needs to be updated to include the trades performed in Day Ahead Market process, day ahead settlements in PRSC and EESC, and suballocations.
  - The Journal Entry allocation system must also be updated to consider these additional parameters, investigate how the calculations change, and determine how the outputs might affect files. PCI needs to be involved in this report, along with other needed upgrades.
- **Credit and Collateral Requirements**
  - As detailed above, the EDAM requirements may require increased credit limits and additional collateral requirements

NVE should also investigate migrating its settlements and invoicing processes to align with CAISO. The CAISO processes statements on business days with particular conventions for resettlement, weekends, etc. They invoice weekly and remit following that. It can be helpful for sub-allocations to follow this calendar convention for many reasons, including the simplicity of tracking which TDs are in what state and matching payments. Currently, NVE is processing monthly and using custom logic to define what is in a month. Migrating to the CAISO cadence may simplify this process.

8.3.3 Software Applications

Settlement software vendors will be requested to extend their packages to accommodate the ISO's EDAM requirements. This includes adding new EDAM-related charge codes and adapting existing WEIM charge codes for EDAM. Additional CAISO settlement charges and inputs will also be reviewed and evaluated. Still, the overall process will remain principally unchanged, and the basic function and workflow of the vendor-supplied software systems are not expected to change.

NVE has indicated that there is no requirement to evaluate new vendor solutions or replace existing systems. The statements will continue to be processed similarly to the current WEIM approach, with new EDAM charge codes baked into the existing WEIM process. This statement can be revisited if the PRSC and EESC Settlement teams are consolidated.

Other entities will join EDAM before NVE and lead the way in identifying and resolving technical and business issues. Ideally, the new EDAM charge codes will be fully defined, and vendor modules will already be updated to reflect the changes due to the earlier entrants. This will reduce the NVE team's effort in building EDAM-ready systems and allow more effort to be focused on the testing itself. NVE should still ensure their vendor actively participates in ISO's EDAM charge code rollout.

8.3.4 Software Interfaces

Adding EDAM settlements to the existing workflow does not add many interfaces between NVE and CAISO. For example, day ahead pricing and award data may be required from the CAISO CMRI system for shadow settlement. This is not considered a "new" interface since the current vendors access data from CMRI for WEIM Settlement. This is an extension of an existing interface with additional data elements.

Source data related to EDAM transmission paths and transmission path contribution may need to be acquired. This data may be sourced from a CAISO system, a participant system, or possibly both. One pathway to providing this data would be for OATI to make the transmission data available, which could then be sent to other settlement systems.

9. REPORTING AND ANALYSIS

9.1 Current State

NVE performs reporting and limited analysis on the WEIM market participation. Users have reported that the tools and reports are adequate. However, they have also shared that other spreadsheets or manual processes have been added to the enterprise tools to increase their ability to complete analysis and related jobs. There are opportunities for additional internal reports and analytics to help review and share daily market participation results.

Internal teams have collaborated to develop RO Hub, designed as an after-the-fact data analysis tool. Multiple sources populate the RO Hub, including CAISO OASIS, CMRI and AVEVA PI data feeds. Mapping and lookup tables are utilized to normalize the data and unit names. This tool uses Oracle Analytics and will eventually provide enhanced dashboard capabilities. Currently, there are no system diagrams or roadmaps detailing what other systems should be included, however, it is a promising deployment that can be enhanced during the EDAM implementation.

Resource Optimization currently analyzes multiple WEIM functions using various data sources and tools such as PCI, SettleCore, and the Oracle BI Daily RO Report. These analyses include:

- RSE results
- Resource dispatches related to economics and physical constraints
- Settlements and Shadow Settlements
- Supply and Load Trends
- Price Trends
- BESS Economics
- Bid Strategy Trends

AVEVA PI is utilized across multiple areas of NVE, including Resource Optimization and System Operations. NVE has fully migrated to PI Vision and there are no ProcessBook deployments remaining. NVE has begun evaluating the PI Asset Framework (AF), however it has not been rolled out and there is no roadmap for migration and adoption. The PI DataLink module is used to manipulate PI data from within MS Excel.

Power users of PI Vision can create their own displays, provided they have access to view the underlying data. For example, the GenDesk uses PI Vision to monitor north loads, south loads, combined native loads, owned generation, 3rd party PPA resources, operating reserves, and spinning reserves.

9.2 EDAM State

Under EDAM the volume and value of settled transactions dramatically increase. Insightful and timely reports and dashboards need to be developed to ensure that NVE has visibility to all the components. NVE also has the benefit of market experience and can specify enterprise tools to be included in the EDAM project. As part of the EDAM software implementation, Utilicast recommends deploying or extending data warehouse tools to ensure staff can collect and correlate validated and verified data categorized with proper metadata.

As noted in the current state section, the RO Hub tool has been reported to be highly successful. Utilicast recommends reviewing the process and technologies used to determine what can be extended while using supportable and extendable tools under the NVE technology roadmap.

Utilicast also recommends a review of the PI Data Historian and Asset Framework (AF) models used to store and process operational data to align data to be queried for EDAM needs.

In addition to robust ad-hoc query capabilities, Utilicast identified the following specific reporting needs for EDAM:

- **EDAM Transmission Allocation vs Revenue Reporting:** Evaluating the quantity and cost of transmission allocated/contributed for EDAM use compared with the revenue gained from making it available for EDAM use
- **Generator Bid Cost Recovery:** Reviewing payments vs cost of generators to ensure that full unit costs are being met and conducting an analysis of why not when false
- **Resource Sufficiency Display:** RSE tests ensure the BAAs participating in EDAM can demonstrate they have enough resources to meet their forecasted demand, imbalance reserves, and ancillary service requirements for the next day, before engaging in energy transfers with other EDAM Entities. A dashboard or report can be created to improve the visibility of the results of these tests, based on the following data elements:
  - Overall Pass/Fail Status: A clear indication of whether the BAA passed the RSE for the operating day
  - Hourly Sufficiency: Potentially a breakdown showing sufficiency status for each of the 24 hours of the Day Ahead Market
  - Coverage of Requirements: Information (potentially high-level) indicating that the offered supply is sufficient to meet the BAA's forecasted demand, imbalance reserves (up and down), and ancillary service needs
  - No Constraint Relaxations: Confirmation that the RSE optimization was able to find a feasible operating plan without needing to relax any supply or demand balance constraints
- **NVE EDAM Benefits Analysis:** NVE currently relies on the CAISO counterfactual reports to capture the WEIM benefits. Internal reporting and calculating of EDAM benefits may be required and is included in the cost estimate as an optional scope item. Data sources for the EDAM benefits analysis include:
  - NVE operational and financial data, such as gen data, load data, bidding data, fuel costs, and bilaterals
  - CAISO data, including LMPs, EDAM Transfers, congestion data, settlement statements and market performance reports
  - Counterfactual data, likely including resource dispatch absent EDAM and WEIM, estimated energy prices, and avoided costs or foregone revenues

- **Other Optional Settlement Analysis and Reports that may arise in EDAM:**
  - Confirm that EDAM awards are consistent with EDAM bids. An automated review of EDAM submitted bids versus EDAM market awards to ensure that generator resource bids are producing expected outcomes.
  - Trending analysis of EDAM Congestion, Loss, and Energy Offset amounts. Understanding if the CAISO's over/under collection of congestion, loss, and energy dollars is neutral or following a trend (desirable or undesirable) may be instructive to overall market strategy.
  - Validate transmission revenue uplift settlements are accurate in shadow settlements and NVE is recovering revenues consistent with objectives and not paying excess costs for other parties' transmission. This will include combining settlement and transmission data, historical comparison calculations, and creating reports.
  - Coincident INCR and DECR awards (price arbitrage) between the three markets (EDAM, FMM, and RTD). For a given Resource and a given time period, did the three markets' awards result in net positive, negative, or neutral settlement dollars? Understanding the market's implied purchase/sale results across the Day Ahead, RUC, FMM, and RTD market may be instructive for the overall strategy.
  - Analysis of generator bid cost recovery payments for EDAM. Where a generator receives a bid cost recovery payment, does the load see an offsetting uplift that is less than, equal to, or greater than the generator's receipts?
  - Reconcile the congestion dollars embedded in EDAM energy settlement versus the congestion revenue returned to the BAA.
  - Impacts of market power mitigation – Frequency and dollar impact (consider OATI's pre-screening tool)
  - DA, FMM, and RT ETSR transfer patterns over time.
  - LMP reports to look at the frequency of spikes, when they occur, and how often they are corrected and a review of the timing, frequency and depth of negative pricing and the value of curtailability/storage.

9.3 Gaps

9.3.1 Staffing

The additional data and financial magnitude of EDAM-related transactions require significant reporting and analytics investments. Several functional areas can benefit from the same or related reports, reducing the overall resource and technology impact. For example, Resource Optimization and Settlements will overlap with data analysis and anomaly detection.

Given both the volume and additional reporting needs, it is recommended that NVE add an additional FTE to perform these analytics and reporting tasks. The following are examples of new data analytics tasks that will be required with EDAM:

- Review market results for correctness
- Analyze the efficiency of managing integrated EDAM/WEIM operations
- Identify issues and anomalies and suggest remediations
- Design and prototype enhanced visualization, reports, metrics, etc.

9.3.2 Business Process

The Entity will need to perform EDAM transmission-based analysis. This would be a new process performed by the Operations or Settlements staff. A new financial analysis (benefits and market performance) will need to be conducted. New reports will be created to communicate data, which will also fall under the settlements and analytics teams.

9.3.3 Software Applications

No new enterprise software should be required for EDAM reporting. Existing vendor-provided software is assumed to operate with required EDAM data points to support its base functional requirements. As part of the EDAM implementation project, the corporate IT direction and cloud-based data and reporting tools should be reviewed, and analytics and reporting should be aligned to ensure proper support and maintenance.

The RO Hub process flow and underlying technology should be reviewed to determine if it can be leveraged for many of these reports and dashboards. Any solution must be maintainable as staff is promoted and roles are changed. Changes must still be made to ensure sufficient, auditable, role-based access control and integration with IT roadmaps.

Ideally, RO Hub should be used as a data 'pond' or information hub. Market-related data can be centralized, related, normalized, and made available for business intelligence tools such as Oracle BI or MS PowerBI.

Settlements can mainly leverage vendor-supplied tools and dedicated analysis tools like Oracle BI to build their reports and dashboards. Rather than a software challenge, the bulk of the effort will be defining the reports and adopting information management practices and tools.

9.3.4 Software Interfaces

New EDAM-related data points from CMRI, OASIS or other sources may be required with the increase in functionality. This is likely a minor impact as these should be known sources with functioning interfaces, and would require additional data fields, but not new interfaces. New PI points may be created as well.

10. SYSTEM OPERATIONS AND RELIABILITY COORDINATOR

The NVE Balancing Authority (BA) is responsible for maintaining a load-resource balance within the metered boundary of the Balancing Authority, as measured by Area Control Error (ACE). The primary functions addressed in the gap assessment are control room system operations and the interactions with the RC West Reliability Coordinator.

NVE will retain all BA responsibilities for maintaining reliability because EDAM is only a Day-Ahead market extension, not a full RTO. The real-time aspects of the WEIM broadly continue in EDAM. Likewise, EDAM is not expected to impact overall reliability processes or the CAISO RC West data exchange requirements dramatically.

10.1 Current State

System Operations

NVE operates from two Control Centers, referred to as "South Control Room" and "North Control Room".

North Control Room:
- 2 Transmission/Distribution Desks and Operators per shift
- 1 Balancing Desk and Operator per shift (BA Operators)
- 1 Real-Time Scheduler per shift
- Support staff on day shifts for EMS, outage coordination, etc.

South Control Room:
- 2 Transmission/Distribution Desks and Operators per shift
  - 1 on nights non-summer months
- 1 EIM desk/engineer per shift
- Support staff on day shifts for EMS, outage coordination, etc.

The following market-facing tasks are performed and managed by the System Operations team:
- BA Operators:
  - Monitor and respond to ADS dispatch signals
  - Consume BAAOP
  - Real-Time Operations
  - Outages
  - Unit start-up / shut down
- EIM Operations Engineers:
  - BAAOP uploads
  - Enter ambient de-rates into webOMS
  - Enter forced outages into webOMS
  - Adjust schedules after T-55 RSE results, if needed

- Enter inputs into ITC, demand response, etc. into BAAOP
- Coordinate with CAISO's RTMO
- Monitor and adjust VER forecasts using BAAOP and/or UL website
- Day Ahead Operations Planning Analysis (OPA) Study Process
- NRI Registration process

Leading up to the operating hour, the WEIM Operations Engineer will check CAISO BSAP to assess the difference between the Market Operator load forecast for the BA and the aggregate Base Schedules. The WEIM Operations Engineer is responsible for making final adjustments to Base Schedules, either in OATI or directly through BSAP, based on:

- Reliability needs of the system
- Compliance requirements
- Failure of one or more sufficiency tests
- Pass of any Flexibility tests tight (Less than 50MW)

The results of CAISO's Five-Minute Market run, RTD, are available in BAAOP for response. If the results are not blocked, CAISO's Automatic Dispatch System (ADS) electronically communicates the Dispatch Operating Target (DOT) for each generating resource within NVE's BA. The instructions are communicated directly into NV Energy's Energy Management System (OSI EMS) via automated interfaces.

The Energy Management System processes the instructions to both participating and non-participating generation resources to move the output to the DOT. The BA Operator will communicate the DOT to any generator not under EMS Automatic Generation Control (AGC). The BA Operator interactively calls specific plants for startups, shutdowns, and MSG transitions.

Outage Management currently occurs across multiple areas of responsibility depending on the type and timing of the outage. The NVE Outage Coordinators, EIM Engineers and BA Operators utilize SunNet's ITOA platform as the primary tool for submitting planned and unplanned Generation and Transmission outages to CAISO. BA Operators need to get notified about any planned or forced outages.

Occasionally, dispatchers need to use CAISO's WebOMS tool directly due to system issues or communication issues between ITOA and CAISO. Generation P_{min} changes are submitted by RO through separate processes via PCI. Ambient derates are calculated by RO and submitted by the EIM Engineers. This generally works well and does not result in conflicts with the BA-submitted limitations.

Reliability Coordinator

NVE successfully meets the RC West Reliability requirements without significant issues today. The RC West data interfaces and data requirements are somewhat extensive, but the points at which they overlap with the ISO Market and market participant actions are limited. This report will focus on the points of intersection between market and RC requirements.

In today's WEIM paradigm, WEIM BAs are required to provide a 4-7 day forward-looking BAA load forecast and Resource Operating Plan. This is supported in WEIM via submission of Day Ahead Base Schedules (proxy for operating plan) and the echo-back of the ISO's Day Ahead WEIM Load Forecasts. These Base Schedules and Load Forecasts are submitted up to 7 days before the operating date, and therefore satisfy the RC West timeline.

Load forecasts and base schedules are submitted by the Resource Optimization team for NVE-owned resources and non-NVE-owned resources scheduled by NVE. Non-NVE schedulers submit Base Schedules for non-participating third-party-generating resources. All Base Schedules are submitted to CAISO's BSAP tool. The Resource Optimization team uses the PCI tool for submitting to BSAP, while third party schedulers submit their Base Schedules directly in CAISO BSAP. Resource Optimization uses a Hitachi Nostradamus-based program called Load Forecast Data Reader to develop the day ahead load forecasts.

Hourly load forecasts are done by CAISO for NVE ahead of time and are used in BSAP for balancing test comparisons. These hourly forecasts are updated twice, first at T-80 and second at T-60, prior to the Operating Hour (T). For real-time forecasts, CAISO ALFS calculates and sends 5 min and 15 min real-time forecasts to BAAOP for Control Room operations.

Other RC West data requirements, studies, and requests lie outside the scope of WEIM or EDAM markets, and these requests have been satisfactorily met today without issue.

10.2 EDAM State

The tasks and duties for System Operations should essentially mirror those performed today in the Day Ahead horizon. They will continue to schedule resources, submit outages, perform manual dispatches and load biasing, manage transmission, and maintain overall system reliability. The training requirements for EDAM will be lower than when NVE joined WEIM. The business process impacts are generally limited to two critical areas.

The first is the day ahead unit commitment and market awards, which will replace the concept of Base Schedules. Further, all resources will become "participating" but in varying capacities dependent on their performance. Resources that can be dispatched every five minutes may continue to be bid into the Real Time market and will additionally be offered day ahead. Resources previously limited to non-participation due to inability to accommodate five-minute dispatch will have the opportunity to be offered into the Day Ahead market and receive hourly economic awards, provided they demonstrate they can be dispatched according to CAISO's requirements. Dispatch will need to implement these awards via the EMS or phone, and precise business processes and notifications will need to be defined. Day Ahead unit commitments of longer start resources should significantly improve the quality of market solutions in real time.

Control Room operations will need training related to the details of the Day Ahead market execution and data requirements and will need to update processes and procedures to respect these time frames. Outage card submission, in particular, can impact Day Ahead Market solution quality, and every effort will be needed to ensure accurate outage cards before 1000 each day.

The second major impact is the addition of a significant amount of transmission scheduling and limit data needed in day ahead timeframes. The transmission scheduling and limit data are discussed in the previous "Transmission Service and Modeling" section. Combined with the pending OATT implementation, these data systems will likely be as complex as the CAISO RTSI interface and of similar importance. The most impactful reliability events triggered by WEIM have been related to transmission system outage or modeling errors, which produced unreliable generation dispatch and subsequently large unscheduled flows due to those dispatches. The advent of Day Ahead market awards and commitment of a much larger portion of the Western interconnection generation fleet poses a risk of these types of errors being significantly more impactful in the future state. NVE will need to fully understand the tools, systems, and mitigation steps needed to protect and reliably operate their transmission system. The likely emergence of a fractured Western interconnection and multiple seams across disparate markets and transmission organizations only increases the risk.

Unlike the traditional WEIM approach to RSE, EDAM will primarily seek to manage RSE failure financially rather than physically isolate BAAs. The RSE management will generally be handled as a pool of EDAM entities based on the DA Awards and RT Bids, rather than on a scheduling-oriented hourly RSE.

The EDAM design continues the WEIM practice of allowing PRSCs and EESCs to protect their RC contingency reserve capacity (Reg Up/Down, Spin, and Non-Spin reserves) from market obligation and dispatch. These capacities will be protected from EDAM market co-optimization once determined by NVE and presented to the ISO at the resource level. Therefore, once identified in the EDAM bidding process, the contingency reserve capacity will be held out of the market and remain available to the BAA Operations. The WEIM Available Balancing Capacity (ABC) concept remains in the EDAM.

10.3 Gaps

10.3.1 Staffing

Joining the EDAM market will increase control room staffing needs for participating BAAs. The expanded market footprint and the complexities of multi-area optimization will require additional personnel with expertise in Day Ahead market operations, inter-BAA scheduling coordination, and real-time monitoring of interchange flows. These new roles will be crucial for managing the increased data streams, ensuring compliance with EDAM protocols, and proactively addressing potential congestion or reliability issues that may arise across the broader interconnected system.

Given the increased complexity and amplified workload with additional advisory market runs, it is recommended that NVE allocate additional resources in the control center for both implementation and long-term post go-live. The following are examples of control room tasks that will be required for EDAM participants:

- Support transmission model and other aspects of system operations changes for the entity, such as, the Transfer Data Template (TDT) changes, CRN registration processes (shared with Transmission Service Staff), and coordinating with adjacent EDAM and WEIM entities
- Determination of flowgates, contingencies, TCORs to be represented in EDAM, coordinated with any existing flowgates, contingencies or TCORs active in NVE WEIM participation.
- Keeping up with EDAM market training, and working to train other internal operator staff as EDAM market changes
- Support new processes for D3 and D2 market advisory runs
    - Outage Coordination into Advisory Market Runs
    - Flowgate, TCOR and Contingency Activation and Conformance in D3 and D2 advisory market runs
    - Review of D3 advisory results, evaluation of possible adjustments to make into D2 advisory run
    - Management of Net Export Constraint as part of D3 and D2 advisory runs
    - Review of D2 advisory results, evaluation of possible adjustments to make into D1 binding run
- Coordination of NVE Operational Planning Analysis (OPA) process with CAISO D3, D2 and D1 runs
- Final binding D1 data inputs
    - Review of Load Forecast and other BA AS obligations inputs for D1 run
    - Final Outage Coordination processes in D-1 Market Run
    - Final Flowgate and Contingency Activation and Conformance processes into D1 market run
    - Determination of D1 Net Export Constraint
- Review of D1 RSE Advisory Results at multiple different timeframes between 6AM and 10AM, communicating with BA sub-entities as applicable
- Review D1 Market Results, including, but not limited to:
    - Generation Awards
    - Intertie Awards (e.g. Transfer System Resource Awards)
    - Market Congestion
- Reviewing e-Tagging of awards, ensuring that all awards are e-Tagged by the market deadline (e.g. 1600). Communicating with transmission customers who were awarded but have not yet e-Tagged.
- Reviewing and monitoring submitted e-Tags to ensure all e-Tags have been appropriately submitted with any required EDAM attributes
- As applicable, working with internal operations staff to submit TSR Type 4 e-Tags

- Carrying out T-5hr e-Tag verifications

During the implementation phase, NVE will need to evaluate how it divides activities described above between EIM Engineers/Analysts and Operator Staff.

To support increased workloads accompanying EDAM participation, it is recommended that an additional 2 EIM/BA Engineer/Analyst FTEs be added during the implementation project to support design, development, and implementation of processes discussed in the list above. This resource requirement will somewhat lessen post go-live, however NVE should expect to dedicate at least 1 FTE EIM/BA Engineer on a long-term basis to support more complex transmission models, system operation changes, and ongoing needs related to the D3, D2, and D1 advisory processes.

In addition, NVE may need to dedicate an operator during EDAM implementation phases, accounting for 1 FTE System Operations Operator during the implementation project. Depending on how NVE implements processes to review day ahead advisory runs and modify market inputs, NVE may need to commit some incremental operator staff to manage ongoing processes supporting the day ahead Advisory Run processes. NVE should assume an additional FTE to support incremental resource needs.

It is not yet known the extent to which many of the processes above will require EIM/BA Engineer/Analyst staffing function to work outside of day shift Monday-Friday hours, and whether NVE should consider 24/7 staffing. Utilicast would recommend that NVE survey early EDAM entrants (e.g. PacifiCorp, PGE, LDWP, and BANC) soon after these entities join EDAM, to determine whether there may be higher staffing needs for control center staff. If 24/7 staffing were deemed necessary, that would add four to five positions that are not included in the resource requirements within this analysis.

These staffing impacts are all associated with the BA function and it is not expected that there will be any incremental staffing needs for satisfying current RC West reliability requirements.

10.3.2 Business Process

In addition to those items discussed in the staffing section above, it is anticipated that the following business processes may need to be implemented or modified:

- Planned and unplanned generation and transmission outage management processes will need to be updated to reflect the new timelines introduced by EDAM participation
    - Determine if the business processes and technical limitations that result in outages being submitted via both ITOA and CAISO webOMS can be resolved
- NVE should thoroughly evaluate the communication of transmission limits, e-Tagging requirements, given the new timelines and data requirements present in EDAM
- In the EDAM, NVE will convert the existing NPRs to PRs with associated offer curves or self-schedules. Modeling decisions that work well in WEIM only may not be adequate in

an environment with day ahead unit commitments or awards that need to be followed hourly

- Resources that can be dispatched hourly but not on a five-minute basis can become bid resources in the Day Ahead Market. Control Room operations will need to be involved in the decision-making for modeling choices to be evaluated for the ability to be implemented by current staff levels and operated reliably, particularly if a unit cannot be controlled via AGC.

10.3.3 Software Applications

Significant changes to OATI webEIM include updates to modify the hourly Base Schedule / RSE workflow and the real-time transmission limit/transmission schedules process. There may also be minor adjustments to RC West data process flows to transition from WEIM data elements to EDAM data elements.

Pricing is not available from OATI for webEDAM enhancements, however, an estimate will be added to the cost modeling worksheet for the license and associated work.

10.3.4 Software Interfaces

Minor changes are likely required to support data push, pull, and merging of WEIM and EDAM.

11. TECHNOLOGY

The organization of this Gap Assessment covers the impact of technology within each functional area, as well as observations and recommendations for improvements.

[redacted]

[redacted]

[redacted]

EDAM-related Implementations

- NVE currently has multiple applications used for commodity deal capture systems: TRM for natural gas transactions; Allegro for power transactions; and Aligne for coal, with the only two coal units remaining in NVE's portfolio scheduled to be converted to natural gas units by June 1, 2026. NVE plans to replace TRM and Allegro with FIS ETRM (formerly known as Aligne) beginning in mid-2025 and completing in mid-2026. This effort will also combine custom bid tools, position reports, and retire homegrown solutions with FIS ETRM.
- Depending on the organizational decision regarding Settlements, the OATI webSettlements tool may be migrated to PCI Settlements. The rationale is detailed in the Settlements section of the assessment report, however, it will result in a considerable amount of technology effort to migrate all users, roles, and functions from the OATI tool to the PCI tool.
- Both the PCI and OATI platforms offer EDAM-specific enhancements to the current NVE tools to enable participation in the EDAM market. While these tools are hosted and not managed by internal resources, there will still need to be dedicated technical resources to assist with the migration, testing, and verification of these tools and the building of any newly identified interfaces. These EDAM modules will also likely increase the associated ongoing maintenance efforts.
- Similar to the current state, CAISO will utilize lower-tier environments such as MAP STAGE for ongoing initiatives and testing. While some efforts may be temporary, new instances and environments, such as QA environments for interacting with the EDAM market, are

included in the scope. This assessment anticipates that some additional lower environment maintenance will be required.

- NVE is executing a Business Transformation Initiative that is striving to update and streamline several technological capabilities. While this initiative does not directly impact the EDAM implementation effort, it will likely introduce competing resource demands, particularly for technology resources.

During deep-dive assessments and follow-up discussions, the following items were observed as adding potential value to NVE; however, they are not critical paths to the EDAM implementation.

- Revamping integrations to allow an API or web service-based interface to retrieve information from OATI rather than flat-file based
- Building an integration from SunNet ITOA to EMS to send outages and associated updates directly into the EMS to support the next-day study process
- Building a display or automated notification to alert Resource Optimization when CAISO is cutting an e-Tag
- Automating the CAISO Settlements downloads via MRI-S
- Automating the meter datafile workflow, including file transfers, format conversions, and external site downloads
- Improving how WEIM transactions are recorded in the General Ledger, enabling automation and quality checking

The following is a summary of which applications will be affected by the EDAM implementation:

Table 7 – EDAM Impacted NVE Systems

Area	System or Technical Impact
Resource Optimization	• PCI EDAM GenManager: bid formulation and submission • PCI GenTrader • ETRM and Deal Capture: FIS ETRM implementation and migration/retirement of homegrown tools and other TRM tools • SettleCore: data feeds and reports incorporating EDAM • Demand Response implementation and integration
Transmission and Tariff	• webTrans Module • OASIS • New EESC system for EDAM, e.g. webEDAM EESC (Shared System Operations)
Metering	• No significant impacts identified

Area	System or Technical Impact
Settlements	• OATI webSettlements • PCI Settlements • After-the-fact (ATF) analysis and reports
Reporting and Analysis	• RO Hub Expansion • Additional reports and dashboards
System Operations	• New EESC system for EDAM, e.g. webEDAM EESC (Shared System Operations) • PI Vision Displays • EMS updates, including potentially adding new units into AGC control • Minor updates to CAISO interfaces
Network Modeling	• No significant impacts identified
Outage Management	• No significant impacts identified
Generation	• No significant impacts identified

12. LEGAL, REGULATORY AND POLICY

The majority of the legal work is related to the OATT tariff drafting and filing, and is documented in the “Transmission OATT And Counterparty Transmission Service Contracts” section.

Joining EDAM involves a comprehensive set of legal, regulatory, and policy activities for any BAA or entity wishing to participate. These activities ensure compliance with CAISO's Tariffs, Federal Energy Regulatory Commission (FERC) regulations, the EDAM Entity’s own OATT, and other applicable laws. The primary areas are as follows:

Understanding the Regulatory Framework

- **CAISO Tariff**: A thorough understanding of the CAISO tariff, specifically Section 33 which pertains to the EDAM, and related sections like Section 27 (Markets and Processes) and Section 11 (Settlements and Billing) is crucial. NVE will need to understand the rules governing market participation, bidding, scheduling, settlements, and obligations.
- **FERC Approval**: The FERC has approved the EDAM design and associated tariff amendments. Participants must adhere to these FERC-approved rules.
- **WECC Requirements**: As the Western Interconnection's reliability coordinator, WECC has specific requirements for participants in regional markets like EDAM.
- **NERC Reliability Standards**: Compliance with North American Electric Reliability Corporation (NERC) standards is essential for all grid operators and market participants.

Legal Agreements and Contracts:

- **EDAM Entity Agreement:** Entities participating in EDAM must execute an agreement with CAISO outlining the terms and conditions of their participation.
- **Open Access Transmission Tariff (OATT):** Participating BAAs must review and adapt their OATT to include specific EDAM implementation, settlements, and operational requirements. This is documented in detail in the *“Transmission OATT And Counterparty Transmission Service Contracts”* section.
- **Implementation Agreement:** A detailed implementation agreement will be developed with CAISO outlining the specific steps, timelines, and responsibilities for onboarding and integration.
- **Metering Agreements:** Metering and data submission agreements must be established according to CAISO's requirements and the Business Practice Manual for Metering.

Policy and Stakeholder Engagement:

- **CAISO Stakeholder Process:** Active participation in CAISO's stakeholder process for EDAM is vital. This involves attending workshops, submitting comments on draft proposals, and staying informed about policy decisions.

- **Internal Policy Adjustments:** NVE will likely need to develop and implement internal policies and procedures to align with the EDAM market rules and operational requirements.
- **Coordination with the Public Utility Commission of Nevada (PUCN):** NVE must coordinate with the PUCN regarding their participation in EDAM and any necessary approvals or filings.

Compliance and Certification

- **Scheduling Coordinator (SC) Certification:** If the participating entity acts as its own Scheduling Coordinator, it must undergo CAISO's SC certification process.
- **Metering Compliance:** Ensuring that metering infrastructure and data submission processes comply with CAISO's Metering Business Practice Manual.
- **Data Reporting Requirements:** Understanding and complying with CAISO's data reporting requirements for market participation and settlements.

System and Infrastructure Readiness

While not strictly "legal, regulatory, or policy," the implementation of these aspects drives significant technical and system requirements that are crucial for legal and regulatory compliance:

- **IT and Application Modifications:** Significant modifications to NVE’s operating and "bid-to-bill" systems will be required to interface with CAISO's market systems.
- **Telemetry and Communication:** Establishing reliable telemetry and communication links with CAISO.
- **Market Simulation and Testing:** Participating in market simulations and testing phases to ensure system readiness and compliance with market rules.

Joining CAISO EDAM requires a significant commitment to understanding and complying with a complex web of legal, regulatory, and policy requirements. This involves thoroughly reviewing tariffs and BPMs, actively participating in stakeholder processes, establishing necessary legal agreements, ensuring compliance with certification and reporting obligations, and making substantial investments in system and infrastructure readiness.

13. NETWORK MODEL, OMS, EMS

Because so much of the functionality of WEIM is needed for EDAM participation, major market functions may have required upgrades for WEIM, and will be able to leverage this prior work and not require additional work for EDAM participation. These are the Network Model, EMS, and OMS.

For EDAM participation, there are no new Network Model requirements or changes. The onboarding process is still under development, however, in the Final Proposal, the CAISO explicitly calls out the Network Model as not requiring any new work: "The onboarding process will include steps similar to the WEIM onboarding activities; although, there may be some elements that are not required for EDAM onboarding because they are already in place given an entity's WEIM participation: CAISO Tariff, section 29.2(b)(3). An example would include the [N]etwork [M]odel-related tasks" (EDAM Final Proposal, Page 11). With no changes for EDAM, NVE will continue to operate as it does today, regularly providing updates to CAISO's Full Network Model via the Master File when there are relevant changes.

While EDAM does not require significant updates to the network model, areas of improvement in the overall model management process were identified during the gap assessment. Specifically, NVE can improve the quality and frequency of neighboring BAA network model updates, expand the load forecast process, and revamp database loads. This will improve the quality of the day ahead power flow studies.

Outages are similarly unchanged from a process and requirements standpoint in WEIM for EDAM participation. EDAM Entities are subject to compliance with Section 9 of the CAISO Tariff. Maintenance outages must be communicated to CAISO at least seven business days before the planned outage, and forced outages must be communicated identically as they are today in WEIM. No new or additional OMS work will be required for EDAM participation.

It is also relevant to highlight the EMS upgrade work that NVE is currently undertaking, as this system is the backbone of numerous major market functions. The replacement project and new OSI system will be complete by mid-2025 and are not expected to impact the EDAM project implementation. While this project will require business process updates and staff training, no additional work in these areas or software or interfaces resulting from EDAM participation should be needed.

13.1 Gaps

No gaps concerning the Network Model, Outages, or EMS have been identified.

APPENDIX A: EDAM COST ESTIMATING MODEL

APPENDIX B: HIGH LEVEL EDAM IMPLEMENTATION SCHEDULE

APPENDIX C: EDAM CONTEXT DIAGRAM

APPENDIX A

Submitted As A Workpaper

APPENDIX B

ID	Task Mode	Task Name	Duration	Start	Finish	Predecessors	Successors
1		**NVE EDAM Conceptual Implementation**	**758 days**	**Mon 6/2/25**	**Wed 6/28/28**		
2		**Milestones**	**738 days**	**Mon 6/2/25**	**Wed 5/31/28**		
3		**Inputs**	**713 days**	**Mon 6/2/25**	**Wed 4/26/28**		
4		Delivery of Gap Assessment Report	0 days	Mon 6/2/25	Mon 6/2/25		20
5		Submit PUCN Filing	0 days	Wed 10/15/25	Wed 10/15/25	40	
6		Implementation Project Start	0 days	Wed 3/18/26	Wed 3/18/26	43	
7		External Stakeholder Process Start	0 days	Thu 3/26/26	Thu 3/26/26	49	
8		File OATT with FERC	0 days	Thu 7/9/26	Thu 7/9/26	53	
9		Begin CAISO Interop Testing	0 days	Thu 11/4/27	Thu 11/4/27	235,258,148,164,179	
10		Begin Parallel Operations	0 days	Wed 4/26/28	Wed 4/26/28	293	
11		**Outputs**	**550 days**	**Wed 3/18/26**	**Wed 5/31/28**		
12		PUCN Approval	0 days	Wed 3/18/26	Wed 3/18/26	43	
13		FERC Tariff Approval	0 days	Fri 9/4/26	Fri 9/4/26	54	
14		PCI Upgrades Complete	0 days	Thu 8/26/27	Thu 8/26/27	148	
15		OATI Upgrades Complete	0 days	Wed 10/6/27	Wed 10/6/27	164,179	
16		NVE Testing Complete	0 days	Thu 1/6/28	Thu 1/6/28	215,250,132,149,180	
17		Go-Live	0 days	Wed 5/31/28	Wed 5/31/28	296	
18		**Track 1 - Project Management**	**293 days**	**Mon 6/2/25**	**Wed 8/26/26**		
19		**Pre-Project Initiation**	**53 days**	**Mon 6/2/25**	**Wed 8/20/25**		
20		Internal decision to join EDAM	5 days	Mon 6/2/25	Fri 6/6/25	4	21
21		Management Recommendation to join EDAM	10 days	Mon 6/9/25	Fri 6/20/25	20	22
22		Offset for Delayed Start - PUCN Filing	23 days	Mon 6/23/25	Wed 7/30/25	21	23
23		Initiate Regulatory Approval Process	15 days	Thu 7/31/25	Wed 8/20/25	22	46,39,45
24		**CAISO Coordination**	**75 days**	**Thu 5/7/26**	**Wed 8/26/26**		
25		Develop Joint Charter with CAISO	15 days	Thu 5/7/26	Wed 5/27/26	56	26
26		Develop Joint Project Schedule with CAISO	30 days	Thu 5/28/26	Wed 7/15/26	25	27
27		Develop Joint Stakeholder Inventory with CAISO	30 days	Thu 7/16/26	Wed 8/26/26	26	275,278
28		**Scoping & Budget**	**105 days**	**Thu 3/19/26**	**Wed 8/26/26**		
29		Define Scope	30 days	Thu 3/19/26	Wed 5/6/26	43	31,30
30		Identify / Contract Consulting Support	45 days	Thu 5/7/26	Wed 7/15/26	29	31,251,252
31		Update 2027 and 2028 Budget	30 days	Thu 7/16/26	Wed 8/26/26	29,30	265
32		**Project Management**	**46 days**	**Thu 3/19/26**	**Thu 5/28/26**		
33		Create Project Issues/Risk Tracker	46 days	Thu 3/19/26	Thu 5/28/26	43	
34		Develop Project Team Roster	46 days	Thu 3/19/26	Thu 5/28/26	43	
35		Execute EDAM Entity Assessment	46 days	Thu 3/19/26	Thu 5/28/26	43	
36		Execute EDAM Project Management Project Startup	46 days	Thu 3/19/26	Thu 5/28/26	43	126,276,62
37		**Track 2 - Regulatory, Stakeholder & Legal**	**600 days**	**Thu 8/21/25**	**Wed 2/2/28**		
38		**State Regulatory**	**135 days**	**Thu 8/21/25**	**Wed 3/18/26**		
39		Prepare PUCN Filing	35 days	Thu 8/21/25	Wed 10/8/25	23	40
40		Submit PUCN Filing	5 days	Thu 10/9/25	Wed 10/15/25	39	41,5
41		PUC Notification Seeking Reg Deferment Order	5 days	Thu 10/16/25	Wed 10/22/25	40	42
42		Draft Declaratory Order	75 days	Thu 10/23/25	Wed 2/25/26	41	43
43		PUC Hearing / Issuance of Declaratory Order (PROJECT START)	15 days	Thu 2/26/26	Wed 3/18/26	42	29,12,33,34,35,36,6,303
44		**Tariff**	**247 days**	**Thu 8/21/25**	**Fri 9/4/26**		
45		Offset for Early Start - Tariff	80 days	Thu 8/21/25	Wed 12/17/25	23	48
46		Contract for Outside Counsel for OATT support	40 days	Thu 8/21/25	Wed 10/15/25	23	47
47		Outside Counsel Onboard	0 days	Wed 10/15/25	Wed 10/15/25	46	48
48		Draft OATT Changes	60 days	Thu 12/18/25	Wed 3/25/26	45,47	49,51
49		Post Draft Tariff	1 day	Thu 3/26/26	Thu 3/26/26	48	50,7
50		External Stakeholder Process	80 days	Fri 3/27/26	Thu 7/30/26	49	
51		Finalize OATT Changes	30 days	Thu 3/26/26	Wed 5/13/26	48	52
52		Post Revised Tariff	10 days	Thu 5/14/26	Wed 5/27/26	51	53FS+10 days
53		File OATT with FERC	16 days	Thu 6/11/26	Thu 7/9/26	52FS+10 days	54FS+36 days,8
54		FERC approval of OATT changes	5 days	Mon 8/31/26	Fri 9/4/26	53FS+36 days	13
55		**CAISO**	**465 days**	**Thu 3/19/26**	**Wed 2/2/28**		
56		Execute Implementation Agreement	30 days	Thu 3/19/26	Wed 5/6/26	43	57,25

ID	Task Mode	Task Name	Duration	Start	Finish	Predecessors	Successors
57		Monitor EDAM Tariff Process / Approval	90 days	Thu 5/7/26	Wed 9/16/26	56	58
58		Monitor EDAM Implementation Details (PAC OATT, BPM, BRS, PGE etc)	315 days	Thu 9/17/26	Wed 12/22/27	57	59
59		Execute Additional Registration Forms / Agreements, Agreement Checklist, SC Agreement	30 days	Thu 12/23/27	Wed 2/2/28	58	
60		~~Track 3 - Resource Configuration & Strategy~~	~~395 days~~	~~Fri 5/29/26~~	~~Thu 12/30/27~~		
61		**Strategy Development**	**115 days**	**Fri 5/29/26**	**Thu 11/12/26**		
62		Conduct Strategy Definition Workshops	10 days	Fri 5/29/26	Thu 6/11/26	36	63
63		Schedule Buffer Offset - Strategy Development	0 days	Thu 6/11/26	Thu 6/11/26	62	65,68,69,74,78,66,181
64		**Day Ahead Transmission Contribution Strategy**	**45 days**	**Fri 6/12/26**	**Thu 8/20/26**		**135,152**
65		Develop Transmission Registration Process	45 days	Fri 6/12/26	Thu 8/20/26	63	83,85
66		Develop Transmission Donation Strategy	45 days	Fri 6/12/26	Thu 8/20/26	63	86
67		**Day Ahead Bidding and Scheduling Strategy**	**105 days**	**Fri 6/12/26**	**Thu 11/12/26**		**135**
68		Create Day Ahead Bidding and Scheduling Strategy	45 days	Fri 6/12/26	Thu 8/20/26	63	70,81
69		Create Resource Sufficiency Evaluation Strategy	45 days	Fri 6/12/26	Thu 8/20/26	63	
70		Review/Update 2-Day Ahead Gas Nomination Strategy	30 days	Fri 8/21/26	Thu 10/1/26	68	71,72
71		Create an Imbalance Reserve Bidding Strategy	30 days	Fri 10/2/26	Thu 11/12/26	70	
72		Create a Load Bidding and Scheduling Strategy	30 days	Fri 10/2/26	Thu 11/12/26	70	120
73		**Generation Participation Strategy**	**105 days**	**Fri 6/12/26**	**Thu 11/12/26**		**135**
74		Create Generation Participation Strategy	30 days	Fri 6/12/26	Thu 7/30/26	63	75
75		Work with IPC on Valmy market submission	45 days	Fri 7/31/26	Thu 10/1/26	74	76
76		Develop approach to migrate selected resources from Non-Participating to Participating	30 days	Fri 10/2/26	Thu 11/12/26	75	99,103,110
77		**Settlements Strategy**	**60 days**	**Fri 6/12/26**	**Thu 9/10/26**		
78		Evaluate merging PRSC and EESC Settlements into combined team	60 days	Fri 6/12/26	Thu 9/10/26	63	216,218
79		**Business Process Development, Modeling & Registration**	**340 days**	**Thu 8/20/26**	**Thu 12/30/27**		
80		**Day Ahead Trading Processes**	**90 days**	**Fri 8/21/26**	**Thu 1/14/27**		**279**
81		Integrate WECC trading processes and timelines with EDAM requirements to provide sufficient supply and flexibility	90 days	Fri 8/21/26	Thu 1/14/27	68	
82		**Transmission Contribution Process Development**	**85 days**	**Thu 8/20/26**	**Thu 1/7/27**		**152,279**
83		Schedule Buffer Offset - Transmission Business Processes	0 days	Thu 8/20/26	Thu 8/20/26	65	84
84		Catalog transmission into Types (Buckets)	10 days	Fri 8/21/26	Thu 9/3/26	83	87,94
85		Clarify transmission priorities internally and with CAISO for Type 4	10 days	Fri 8/21/26	Thu 9/3/26	65	87
86		Determine whether DNR undesignation is required to support EDAM Transfers	10 days	Fri 8/21/26	Thu 9/3/26	66	
87		Establish EDAM Internal and External Interties	30 days	Fri 9/4/26	Thu 10/15/26	85,84	88
88		Identify EDAM Transfer Locations / Transfer System Resource Locations and determine types of TSRs supported	10 days	Fri 10/16/26	Thu 10/29/26	87	89
89		Develop Bucket 3 / Type 4 Unsold Firm and Unscheduled Firm encumbrance processes	10 days	Fri 10/30/26	Thu 11/12/26	88	90
90		Develop process for retrieval of EDAM transmission obligations	10 days	Fri 11/13/26	Thu 12/3/26	89	91
91		Develop process for e-Tagging of awards	10 days	Fri 12/4/26	Thu 12/17/26	90	92
92		Update process flow documentation	5 days	Fri 12/18/26	Thu 1/7/27	91	
93		**Transmission Registration**	**94 days**	**Thu 9/3/26**	**Wed 2/3/27**		
94		Register Transmission Paths (obtain CRN) - Initial for Testing	0 days	Thu 9/3/26	Thu 9/3/26	84	95
95		Register Transmission Paths (obtain CRN) - Updates for Market Sim	30 days	Fri 9/4/26	Thu 10/15/26	94	96
96		Register Transfer Data Template (TDT) / IRDT Changes – for initial testing	30 days	Fri 10/16/26	Thu 12/3/26	95	97
97		Register Transfer Data Template (TDT) / IRDT Changes – updates for Market Simulation	34 days	Fri 12/4/26	Wed 2/3/27	96	
98		**NPR to PR Migration**	**140 days**	**Fri 11/13/26**	**Thu 6/17/27**		
99		Evaluate which units are moving to Participating	50 days	Fri 11/13/26	Thu 2/11/27	76	100
100		Identify required artifacts	50 days	Fri 2/12/27	Thu 4/22/27	99	101
101		Execute migration from NPR to PR (details pending NVE input)	40 days	Fri 4/23/27	Thu 6/17/27	100	255
102		**GRDT Updates**	**280 days**	**Fri 11/13/26**	**Thu 12/30/27**		
103		Evaluate Concepts of PR and NPR in EDAM	50 days	Fri 11/13/26	Thu 2/11/27	76	104,260
104		Evaluate GRDT Parameter Updates	50 days	Fri 2/12/27	Thu 4/22/27	103	105,112,117
105		Evaluate DA Interpretation of GRDT Parameters	40 days	Fri 4/23/27	Thu 6/17/27	104	106,255
106		GRDT Updates for Testing	30 days	Fri 6/18/27	Thu 7/29/27	105	107

ID	Task Mode	Task Name	Duration	Start	Finish	Predecessors	Successors
107		GRDT Updates for Parallel	90 days	Fri 7/30/27	Thu 12/2/27	106	108
108		GRDT Updates for Prod	20 days	Fri 12/3/27	Thu 12/30/27	107	
109		**Network Model Changes (if necessary)**	**180 days**	**Fri 11/13/26**	**Thu 8/12/27**		
110		Refresh the network model and improve the process	180 days	Fri 11/13/26	Thu 8/12/27	76	
111		**MMA & DEB Update**	**154 days**	**Fri 4/23/27**	**Wed 11/24/27**		
112		Collect data from plants on maintenance costs during EIM years	40 days	Fri 4/23/27	Thu 6/17/27	104	113
113		Assess if what additional maint costs will be incurred w/EDAM	60 days	Fri 6/18/27	Thu 9/9/27	112	114
114		Update MMAs, file and negotiate with CAISO	40 days	Fri 9/10/27	Thu 11/4/27	113	115
115		Approval of updated MMAs	12 days	Fri 11/5/27	Mon 11/22/27	114	116
116		MMAs Take effect	2 days	Tue 11/23/27	Wed 11/24/27	115	
117		Assess if DEB needs updating	60 days	Fri 4/23/27	Thu 7/15/27	104	118
118		File DEB changes with CAISO	40 days	Fri 7/16/27	Thu 9/9/27	117	
119		**Third-Party Load and Generation**	**210 days**	**Fri 11/13/26**	**Thu 9/23/27**		
120		Determine Scheduling Coordinator options for Third Party LSEs and Generators	30 days	Fri 11/13/26	Thu 1/14/27	72	121,167
121		Determine requirements for Load Forecasts, Metering & Transmission Service Registration	30 days	Fri 1/15/27	Thu 2/25/27	120	122,167
122		Determine options and requirements for Day Ahead Load Bidding	30 days	Fri 2/26/27	Thu 4/8/27	121	123
123		Determine how RSE requirements and penalties are sub-allocated to Third Party LSEs	30 days	Fri 4/9/27	Thu 5/20/27	122	124
124		Conduct Third Party Load and Gen Outreach	90 days	Fri 5/21/27	Thu 9/23/27	123	174
125		Track 4 - Systems Integration & Testing	400 days	Fri 5/29/26	Thu 1/6/28		
126		Develop Approach and Negotiation Strategy	20 days	Fri 5/29/26	Thu 6/25/26	36	128,216
127		**Allocation for RFP / Contracting**	**70 days**	**Fri 6/26/26**	**Thu 10/8/26**		
128		EIM Replacement Requirements for Contracting	20 days	Fri 6/26/26	Thu 7/30/26	126	129
129		EDAM Requirements for Contracting	20 days	Fri 7/31/26	Thu 8/27/26	128	130
130		Contract Negotiations	30 days	Fri 8/28/26	Thu 10/8/26	129	131
131		Vendor Start Date	0 days	Thu 10/8/26	Thu 10/8/26	130	134,151,167
132		**PCI EDAM Software**	**215 days**	**Fri 10/9/26**	**Thu 8/26/27**		**16**
133		**Requirements**	**40 days**	**Fri 10/9/26**	**Thu 12/10/26**		
134		Conduct Deep Dive with PCI to understand roadmap and functionality	5 days	Fri 10/9/26	Thu 10/15/26	131	135
135		Conduct internal workshops for specific functional and technical requirements	15 days	Fri 11/13/26	Thu 12/10/26	134,64,67,73	137
136		**Implementation**	**90 days**	**Fri 12/11/26**	**Thu 4/29/27**		
137		Document design and implementation details	30 days	Fri 12/11/26	Thu 2/4/27	135	138,139,191,199,209
138		Perform necessary upgrades to support EDAM (Vendor)	60 days	Fri 2/5/27	Thu 4/29/27	137	
139		Develop any required interfaces	40 days	Fri 2/5/27	Thu 4/1/27	137	141
140		**Configuration**	**45 days**	**Fri 4/2/27**	**Thu 6/3/27**		
141		Configure the PCI system to support NVE's EDAM strategies	20 days	Fri 4/2/27	Thu 4/29/27	139	142
142		Configure the PCI system to re-optimize current bidding strategies and plans	20 days	Fri 4/30/27	Thu 5/27/27	141	143
143		Update PCI documentation with all updates and customizations	5 days	Fri 5/28/27	Thu 6/3/27	142	145,277
144		**Testing**	**60 days**	**Fri 6/4/27**	**Thu 8/26/27**		
145		FAT	20 days	Fri 6/4/27	Thu 7/1/27	143	146
146		SAT	20 days	Fri 7/2/27	Thu 7/29/27	145	147
147		UAT	20 days	Fri 7/30/27	Thu 8/26/27	146	148
148		PCI EDAM Upgrades ready for parallel operations	0 days	Thu 8/26/27	Thu 8/26/27	147	14,288,9
149		**OATI EDAM Software**	**244 days**	**Fri 10/9/26**	**Wed 10/6/27**		**16**
150		**Requirements**	**65 days**	**Fri 10/9/26**	**Thu 1/28/27**		
151		Conduct Deep Dive with OATI to understand roadmap and functionality	5 days	Fri 10/9/26	Thu 10/15/26	131	152
152		Conduct internal workshops for specific functional and technical requirements	15 days	Fri 1/8/27	Thu 1/28/27	64,82,151	154
153		**Implementation**	**115 days**	**Fri 1/29/27**	**Thu 7/8/27**		
154		Document design and implementation details	15 days	Fri 1/29/27	Thu 2/18/27	152	155,191,199,209
155		Perform necessary upgrades to support EDAM (Vendor)	60 days	Fri 2/19/27	Thu 5/13/27	154	156
156		Develop any required interfaces	40 days	Fri 5/14/27	Thu 7/8/27	155	158
157		**Configuration**	**25 days**	**Fri 7/9/27**	**Thu 8/12/27**		
158		Configure the OATI system to support NVE's EDAM strategies	20 days	Fri 7/9/27	Thu 8/5/27	156	159
159		Update OATI documentation with all updates and customizations	5 days	Fri 8/6/27	Thu 8/12/27	158	161,277
160		**Testing**	**39 days**	**Fri 8/13/27**	**Wed 10/6/27**		

ID	Task Mode	Task Name	Duration	Start	Finish	Predecessors	Successors
161		FAT	10 days	Fri 8/13/27	Thu 8/26/27	159	162
162		SAT	14 days	Fri 8/27/27	Wed 9/15/27	161	163
163		UAT	15 days	Thu 9/16/27	Wed 10/6/27	162	164
164		OATI EDAM Upgrades ready for parallel operations	0 days	Wed 10/6/27	Wed 10/6/27	163	15,288,9
165		**Transmission Customer Portal**	**155 days**	**Fri 2/26/27**	**Thu 9/30/27**		**16**
166		**Requirements**	**20 days**	**Fri 2/26/27**	**Thu 3/25/27**		
167		Gather requirements for transmssion customer portal	5 days	Fri 2/26/27	Thu 3/4/27	131,120,121	168
168		Work with selected vendor on implemenation options	15 days	Fri 3/5/27	Thu 3/25/27	167	170
169		**Implementation**	**55 days**	**Fri 3/26/27**	**Thu 6/10/27**		
170		Document design and implementation details	15 days	Fri 3/26/27	Thu 4/15/27	168	171,191,199,209
171		Develop any required interfaces	40 days	Fri 4/16/27	Thu 6/10/27	170	173,176,277
172		**Outreach**	**80 days**	**Fri 6/11/27**	**Thu 9/30/27**		
173		Develop Training and Outreach materials	20 days	Fri 6/11/27	Thu 7/8/27	171	
174		Conduct Outreach and Training with Tranmission Customers	5 days	Fri 9/24/27	Thu 9/30/27	124	
175		**Testing**	**60 days**	**Fri 6/11/27**	**Thu 9/2/27**		
176		FAT	20 days	Fri 6/11/27	Thu 7/8/27	171	177
177		SAT	20 days	Fri 7/9/27	Thu 8/5/27	176	178
178		UAT	20 days	Fri 8/6/27	Thu 9/2/27	177	179
179		Transmission Customer Portal ready for parallel operations	0 days	Thu 9/2/27	Thu 9/2/27	178	15,288,9
180		**Demand Response Integration**	**260 days**	**Fri 6/12/26**	**Thu 7/8/27**		**16**
181		Design Requirements	60 days	Fri 6/12/26	Thu 9/10/26	63	182,191,199,209
182		Strategy for DER's	30 days	Fri 9/11/26	Thu 10/22/26	181	183
183		PCI Integration	30 days	Fri 10/23/26	Thu 12/10/26	182	184
184		Implementation	60 days	Fri 12/11/26	Thu 3/18/27	183	185
185		FAT	20 days	Fri 3/19/27	Thu 4/15/27	184	186
186		SAT	20 days	Fri 4/16/27	Thu 5/13/27	185	187
187		UAT	20 days	Fri 5/14/27	Thu 6/10/27	186	188
188		Documentation and Cutover	20 days	Fri 6/11/27	Thu 7/8/27	187	189
189		Demand Response Integration ready for parallel operations	0 days	Thu 7/8/27	Thu 7/8/27	188	288,9
190		**Integration**	**120 days**	**Fri 4/16/27**	**Thu 9/30/27**		**16**
191		Base Requirements	30 days	Fri 4/16/27	Thu 5/27/27	137,154,170,181	192
192		Design Details	20 days	Fri 5/28/27	Thu 6/24/27	191	193
193		Development	20 days	Fri 6/25/27	Thu 7/22/27	192	194
194		Testing and Bug Fixes	20 days	Fri 7/23/27	Thu 8/19/27	193	195
195		Documentation Updates	30 days	Fri 8/20/27	Thu 9/30/27	194	196
196		Integration Updates ready for parallel operations	0 days	Thu 9/30/27	Thu 9/30/27	195	288,9
197		**Reporting & Analytics**	**190 days**	**Fri 4/16/27**	**Thu 1/6/28**		
198		**RO Hub Expansion**	**190 days**	**Fri 4/16/27**	**Thu 1/6/28**		**16**
199		Base Requirements	10 days	Fri 4/16/27	Thu 4/29/27	137,154,170,181	200
200		Design Details	20 days	Fri 4/30/27	Thu 5/27/27	199	202
201		**Development**	**120 days**	**Fri 5/28/27**	**Thu 11/11/27**		**206**
202		Prototype	20 days	Fri 5/28/27	Thu 6/24/27	200	203
203		Refinements	10 days	Fri 6/25/27	Thu 7/8/27	202	204
204		Data Source Integrations	30 days	Fri 7/9/27	Thu 8/19/27	203	205
205		Dashboard and Report Development	60 days	Fri 8/20/27	Thu 11/11/27	204	
206		Testing	20 days	Fri 11/12/27	Thu 12/9/27	201	207
207		Documentation Updates	20 days	Fri 12/10/27	Thu 1/6/28	206	
208		**Internal Tool Development**	**110 days**	**Fri 4/16/27**	**Thu 9/16/27**		**16**
209		Base Requirements	10 days	Fri 4/16/27	Thu 4/29/27	137,154,170,181	210
210		Design Details	20 days	Fri 4/30/27	Thu 5/27/27	209	211
211		Development	40 days	Fri 5/28/27	Thu 7/22/27	210	212
212		Testing	20 days	Fri 7/23/27	Thu 8/19/27	211	213
213		Documentation Updates	20 days	Fri 8/20/27	Thu 9/16/27	212	
214		**Track 5 - Metering & Settlements**	**326 days**	**Thu 7/16/26**	**Thu 11/4/27**		
215		**Settlements Implementation**	**225 days**	**Fri 9/11/26**	**Thu 8/12/27**		**16**
216		Approach / Negotiation Strategy	45 days	Fri 9/11/26	Thu 11/12/26	78,126	226

ID	Task Mode	Task Name	Duration	Start	Finish	Predecessors	Successors
217		**Business Process Development**	**80 days**	**Fri 9/11/26**	**Thu 1/21/27**		
218		Evaluate and Understand EDAM Charges	20 days	Fri 9/11/26	Thu 10/8/26	78	219
219		Develop Approach and Processes to Shadow Settle EDAM Charges	10 days	Fri 10/9/26	Thu 10/22/26	218	220
220		Develop Approach and Processes to Validate CAISO Invoices and Statements	10 days	Fri 10/23/26	Thu 11/5/26	219	221
221		Develop Approach and Processes for Transmission Transfer Revenue Allocation	10 days	Fri 11/6/26	Thu 11/19/26	220	222
222		Update Deferred Energy Report Processes	10 days	Fri 11/20/26	Thu 12/10/26	221	223
223		Develop Approach and Processes to Sub-Allocate EDAM Charges	10 days	Fri 12/11/26	Thu 1/7/27	222	224
224		Develop Approach and Processes to Calculate EDAM Market Benefits	10 days	Fri 1/8/27	Thu 1/21/27	223	227,237
225		**Software Updates**	**180 days**	**Fri 11/13/26**	**Thu 8/12/27**		
226		Contract Negotiations	15 days	Fri 11/13/26	Thu 12/10/26	216	
227		Design Details	35 days	Fri 1/22/27	Thu 3/11/27	224	228
228		Integration	10 days	Fri 3/12/27	Thu 3/25/27	227	229
229		Development	60 days	Fri 3/26/27	Thu 6/17/27	228	230,277
230		FAT	10 days	Fri 6/18/27	Thu 7/1/27	229	231
231		SAT	10 days	Fri 7/2/27	Thu 7/15/27	230	232
232		UAT	10 days	Fri 7/16/27	Thu 7/29/27	231	233
233		Bug Fixes and Cutover	5 days	Fri 7/30/27	Thu 8/5/27	232	234
234		Documentation Updates	5 days	Fri 8/6/27	Thu 8/12/27	233	235
235		Settlements ready for parallel operations	0 days	Thu 8/12/27	Thu 8/12/27	234	288,9
236		**Settlements Reporting/Analytics**	**190 days**	**Fri 1/22/27**	**Thu 10/14/27**		
237		Requirements for PCI	30 days	Fri 1/22/27	Thu 3/4/27	224	239
238		**Report Development**	**160 days**	**Fri 3/5/27**	**Thu 10/14/27**		
239		Transmission Lost Revenue - Justification, Received, Paid	10 days	Fri 3/5/27	Thu 3/18/27	237	240
240		Anomaly Detection Reports	10 days	Fri 3/19/27	Thu 4/1/27	239	241
241		EDAM Benefits Reports	10 days	Fri 4/2/27	Thu 4/15/27	240	242
242		Market Use of Transmission	10 days	Fri 4/16/27	Thu 4/29/27	241	243
243		Hoover Participation Discussion	10 days	Fri 4/30/27	Thu 5/13/27	242	244
244		EDAM Impacts on Existing Reports	10 days	Fri 5/14/27	Thu 5/27/27	243	245
245		Design Details	10 days	Fri 5/28/27	Thu 6/10/27	244	246
246		Integration Details	10 days	Fri 6/11/27	Thu 6/24/27	245	247
247		Development	45 days	Fri 6/25/27	Thu 8/26/27	246	248
248		Testing	15 days	Fri 8/27/27	Thu 9/16/27	247	249
249		Documentation Updates	20 days	Fri 9/17/27	Thu 10/14/27	248	
250		**Metering**	**326 days**	**Thu 7/16/26**	**Thu 11/4/27**		**16**
251		Physical Metering Assessment Document	40 days	Thu 7/16/26	Wed 9/9/26	30	256
252		Determine Metering Updates	40 days	Thu 7/16/26	Wed 9/9/26	30	253,254
253		Coordination with third party for metering changes	174 days	Thu 9/10/26	Tue 6/1/27	252	
254		Perform Metering Work	174 days	Thu 9/10/26	Tue 6/1/27	252	
255		Assess any Needed SQMD Updates	40 days	Fri 6/18/27	Thu 8/12/27	105,101	256
256		Update SQMDs	30 days	Fri 8/13/27	Thu 9/23/27	255,251	257
257		Submit and review SQMDs	30 days	Fri 9/24/27	Thu 11/4/27	256	258
258		Metering ready for parallel operations	0 days	Thu 11/4/27	Thu 11/4/27	257	9
259		**Credit**	**120 days**	**Fri 2/12/27**	**Thu 7/29/27**		**16**
260		Determine revised EDAM Credit Limit	40 days	Fri 2/12/27	Thu 4/8/27	103	261
261		Secure collateral and letter of credit	40 days	Fri 4/9/27	Thu 6/3/27	260	262
262		Submit updated credit limits and collateral to CAISO	40 days	Fri 6/4/27	Thu 7/29/27	261	294
263		**Track 6 - Training & Readiness**	**436 days**	**Fri 5/29/26**	**Fri 2/25/28**		
264		**Staffing**	**377 days**	**Thu 8/27/26**	**Fri 2/25/28**		
265		Evaluate staffing needs across the business and identify add'l headcount	42 days	Thu 8/27/26	Fri 10/23/26	31	266
266		Formally request additional positions	46 days	Mon 10/26/26	Mon 1/18/27	265	267
267		Create position descriptions	24 days	Tue 1/19/27	Fri 2/19/27	266	268
268		Advertise job postings/application period	45 days	Mon 2/22/27	Fri 4/23/27	267	269
269		Work with HR on needed changes to existing job descriptions	30 days	Mon 4/26/27	Fri 6/4/27	268	270
270		Interview for new positions	45 days	Mon 6/7/27	Fri 8/6/27	269	271
271		Make offers for new positions	30 days	Mon 8/9/27	Fri 9/17/27	270	272
272		Onboard new staff	55 days	Mon 9/20/27	Fri 12/3/27	271	273

ID	Task Mode	Task Name	Duration	Start	Finish	Predecessors	Successors
273		Make any org changes	60 days	Mon 12/6/27	Fri 2/25/28	272	
274		**Training**	**372 days**	**Fri 5/29/26**	**Mon 11/29/27**		
275		Initial CAISO EDAM Training / CBT Style Intros	40 days	Thu 8/27/26	Wed 10/21/26	27	
276		Project SME Training	40 days	Fri 5/29/26	Thu 7/30/26	36	279
277		Vendor system training	32 days	Fri 8/13/27	Mon 9/27/27	143,159,171,229	279
278		Market & CAISO-Facing Concepts	20 days	Thu 8/27/26	Wed 9/23/26	27	279
279		Business Process Training	20 days	Tue 9/28/27	Mon 10/25/27	278,80,82,276,277	280,282
280		Business Procedure Training	25 days	Tue 10/26/27	Mon 11/29/27	279	
281		**Project Readiness Criteria**	**75 days**	**Tue 10/26/27**	**Mon 2/7/28**		
282		Readiness Criteria Evidence	40 days	Tue 10/26/27	Mon 12/20/27	279	283
283		Readiness Criteria Dashboard	20 days	Tue 12/21/27	Mon 1/17/28	282	284
284		Parallel Operations EDAM Activation Plan	10 days	Tue 1/18/28	Mon 1/31/28	283	285,294
285		EDAM Activation Plan	5 days	Tue 2/1/28	Mon 2/7/28	284	
286		~~**Track 7 - CAISO Interop and Cutover**~~	~~**190 days**~~	~~**Wed 10/6/27**~~	~~**Wed 6/28/28**~~		
287		**CAISO Testing Phases**	**140 days**	**Wed 10/6/27**	**Wed 4/19/28**		
288		Schedule Buffer Offset - CAISO Testing	0 days	Wed 10/6/27	Wed 10/6/27	235,148,164,179,189	289
289		CAISO Connectivity Testing	20 days	Thu 10/7/27	Wed 11/3/27	288	290
290		Joint Integration Testing	60 days	Thu 11/4/27	Wed 1/26/28	289	291
291		Market Simulation	60 days	Thu 1/27/28	Wed 4/19/28	290	293
292		**Cutover**	**50 days**	**Thu 4/20/28**	**Wed 6/28/28**		
293		Parallel Prep	5 days	Thu 4/20/28	Wed 4/26/28	291	294,10
294		Parallel Ops	20 days	Thu 4/27/28	Wed 5/24/28	293,284,262	295
295		Go-Live Prep	5 days	Thu 5/25/28	Wed 5/31/28	294	296
296		Go-Live	0 days	Wed 5/31/28	Wed 5/31/28	295	297,17
297		Stabilization & Analysis	20 days	Thu 6/1/28	Wed 6/28/28	296	
298							
299							
300							
301							
302		**Task Durations for Cost Estimating Spreadsheet**					
303		Project Start Date	0 days	Wed 3/18/26	Wed 3/18/26	43	
304		PMO Setup	46 days?	Thu 3/19/26	Thu 5/28/26		
305		Strategy Development	106 days?	Thu 6/11/26	Thu 11/12/26		
306		Business Processes - RO	200 days?	Fri 8/21/26	Thu 6/17/27		
307		Business Processes - Transmission	86 days	Thu 8/20/26	Thu 1/7/27		
308		Business Processes - BAA	180 days	Fri 11/13/26	Thu 8/12/27		
309		Business Processes - Settlements & Metering	80 days	Fri 9/11/26	Thu 1/21/27		
310		Business Processes - Third-Party Gen & Load	120 days?	Fri 11/13/26	Thu 5/20/27		
311		Solution Implementation- PRSC	215 days?	Fri 10/9/26	Thu 8/26/27		
312		Solution Implementation - EESC	244 days	Fri 10/9/26	Wed 10/6/27		
313		Solution Implementation - Settlements	180 days	Fri 11/13/26	Thu 8/12/27		
314		Solution Implementation - Tx Cust Portal	135 days	Fri 2/26/27	Thu 9/2/27		
315		Solution Implementation - Internal Apps	110 days	Fri 4/16/27	Thu 9/16/27		
316		Reporting and Analytics Implementation	190 days?	Fri 4/16/27	Thu 1/6/28		
317		Third Party Outreach	90 days?	Fri 5/21/27	Thu 9/23/27		
318		Settlements Updates	190 days?	Fri 1/22/27	Thu 10/14/27		
319		Metering Updates	326 days?	Thu 7/16/26	Thu 11/4/27		
320		Credit Updates	120 days?	Fri 2/12/27	Thu 7/29/27		
321		Market Training	20 days?	Thu 8/27/26	Wed 9/23/26		
322		Process Training and OCM	45 days?	Tue 9/28/27	Mon 11/29/27		
323		CAISO Testing and Go Live	171 days?	Wed 10/6/27	Wed 5/31/28		
324		REG: PUCN Filing and Initial Requirements	60 days?	Thu 7/31/25	Wed 10/22/25		
325		REG: OATT Tariff	167 days	Thu 12/18/25	Fri 9/4/26		
326		REG: External Stakeholder Process	80 days?	Fri 3/27/26	Thu 7/30/26		
327		Post Go-Live Support	20 days?	Thu 6/1/28	Wed 6/28/28		
328		Project Startup	188 days?	Mon 6/2/25	Wed 3/18/26		
329		Project Implementation	571 days?	Wed 3/18/26	Wed 6/28/28		

APPENDIX C